













Alpine ENERGY

ASSET MANAGEMENT PLAN
2016–2026

ASSET MANAGEMENT PLAN

ALPINE ENERGY LIMITED

Planning period: 1 April 2016 to 31 March 2026
Disclosure date: 31 March 2016

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DIRECTORS' STATEMENT

The purpose of our 2016 to 2026 Asset Management Plan (AMP) is to provide insight and explanation of how we intend to provide electricity distribution services. We are committed to managing our distribution assets in a safe, reliable, and cost-effective manner that addresses required service levels and maintains a robust energy delivery system for our stakeholders.

Our asset management disclosures consist of two documents. The first document is this AMP and the second is our Asset Management Plan—Major Assets (AMP—Major Assets). The primary purpose of the AMP—Major Assets is to provide our staff and contractors with key information on major assets and network development in the most accessible form. Together, the AMP and AMP—Major Assets have been published to meet our regulatory requirements for asset management under the Electricity Distribution Information Disclosure 2012.

Our distribution network is in a fair to good condition. Assets built in the 1950s and 1960s are near the end of expected service life. However, the majority of older assets will be able to safely continue in service for the next 8 to 10 years. Assets that have served expected life or have become uneconomic will be retired and replaced with alternative products.

We continue our investment phase by identifying and committing funds for network developments. Developments are identified that best serve our consumers for the next 50 years i.e. the average life of an electricity distribution asset.

Our investment in the network is funded through our tariffs that are set in accordance with our pricing methodology. It is our intention to continue to keep tariffs within the price path set by the Commerce Commission and have a pricing methodology that is consistent with the Electricity Authority's pricing principles.

Capacity increases at grid exit points will be addressed through new investment agreements with Transpower, with a resulting price pass through to consumers as is now the case. Sole beneficiaries identified for additional capacity will have back-to-back agreements to minimise the risk of stranded assets.

We encourage consumers to comment on both documents and the approach taken to maintain a cost-effective, safe, and reliable supply to South Canterbury.

The Directors

Alpine Energy Limited

DIRECTOR CERTIFICATION

Certification for Asset Management Plan 2016–2026.

We, Stephen Richard Thompson and Alister John France, being directors of Alpine Energy Limited certify that, having made all reasonable enquiries, to the best of our knowledge—

a) the Asset Management Plan 2016–2026 of Alpine Energy Limited prepared for the purposes of clause 2.6.1 and sub clauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) 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.

Stephen Richard Thompson
30 March 2016

Alister John France
30 March 2016

CONTENTS

1. EXECUTIVE SUMMARY

1.1 The purpose of the plan

Our AMP provides insight and explanation of how we intend to provide electricity distribution services by managing our distribution assets in a safe, reliable, and cost effective manner that addresses required service levels and maintains a robust energy delivery system to our stakeholders.

Our AMP also defines the major initiatives and projects that will meet stakeholder and consumer requirements for the planning period. Preparing the AMP in this format enables us to comply with mandatory disclosure requirements set out in *Attachment A—Asset Management Plans* of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2015 (consolidated in 2015), 24 March 2015 (IDD Determination).

1.2 Key assumptions

Our asset management decision making processes are based on key assumptions. The key assumptions are described further below and throughout this document.

1.2.1 General economic assumptions

Since its four-year high of 3.70% in September 2014, the NZ 90 Day Bank Bill interest rate has dropped to 2.84%[1]. It is forecast to further decrease to 2.63% by March 2016 and stabilise at 2.67% until December 2016.

New Zealand's external liabilities have declined since from a peak of 85% of GDP in 2009 to 62% in June 2015. However, New Zealand's net external liabilities as a share of GDP remain elevated compared to some other countries, leaving the economy vulnerable to tighter funding conditions if the cost or availability of offshore funding increases significantly[2].

ANZ's NZ Economic Outlook of September 2015 reported that New Zealand's annual growth rate is tracking a little below 2%. In addition, the unemployment rate has risen to close to 6%. The ANZ Outlook points to three main domestic contributors to this slow down: weaker terms of trade, plateauing of the earthquake rebuild, and growth in credit above GDP with reduction in household saving.

On the positive side, the ANZ Outlook points to:

- improvement in the competitiveness of some industries, including tourism
- the construction sector remaining steady with residential investment forecast to grow 6% over 2016
- migration remaining strong
- business confidence remaining good

[1] As at 30 September 2015
[2] Refer to the Reserve Bank of New Zealand's (RBNZ) latest Financial Stability Report of November 2015 for details on the RBNZ's current view of the New Zealand Economy.

- the housing market responding to lower interest rates
- New Zealand equities performing better than some global peers amidst uncertainty
- financial conditions encouraging growth
- the NZ microeconomic story and self-belief remaining strong.

1.2.1.1 Meeting increasing demand

We estimate that the demand for new connections during 2015 was 20% higher than 2014. Growth in demand includes: irrigation, industrial, commercial, and domestic subdivision connections and extensions. Although dairy conversions were down on 2014, growth is still driven by irrigation development and is close to historical long-run averages throughout the planning period.

We recognise the fact that the economy depends on a secure and reliable electricity supply. Investment in our network will ensure that necessary network capacity is available to support increasing demand.

1.2.1.2 Capital investment

We have reported network capital investment over 10 years based on projects with high priority due to capacity or security constraints. Some projects will be conditional on third party decisions or developments such as consumer projects proceeding and resource consents being granted for irrigation schemes. Appendix B summarises the Capex spend on capital investment projects.

1.2.1.3 Investment in transmission assets

Some transmission projects are required in order to provide satisfactory security and capacity at the GXP or transmission lines within the region.

We will continue to deliver Transpower GXP capacity, grid support projects, and security requirements to current service levels. We pass through transmission costs to consumers through our tariffs.

1.2.1.4 New technology

We view distributed generation as an enabling technology for network support rather than network replacement. We assume no new technologies with the ability to entirely substitute for electricity network development will become available during the planning period.

1.2.1.5 NETcon

We will continue to use NETcon Limited as our preferred contractor for construction and maintenance services.

1.2.1.6 Compliance

As a monopoly service provider we are subject to both economic and market regulation by the Commerce Commission and Electricity Authority respectively. During the planning period we will ensure compliance with relevant Acts and Regulations.

1.2.1.7 Shareholder requirements

During the planning period we will meet our shareholders' requirements by achieving the objectives set down in our mission statement.

1.2.1.8 Year-on-year line charge increases

Each year we set prices in a manner that ensures that we comply with the default price-quality path set by the Commerce Commission, while earning sufficient revenue to fund the continued enhancement of the reliability and security of our network.

Under the DPP Determination, our price increases are capped at CPI + 11% each year until 2020. We are mindful of the impact price increases have on households and businesses. And are equally mindful of our obligation to balance cost increases against the need to provide a resilient network for our growing communities.

1.3 Period covered by the AMP

This AMP covers the period 1 April 2016 to 31 March 2026 and was approved by our Board on 30 March 2016. The AMP was publicly disclosed by 31 March 2016 in accordance with the IDD Determination.

1.4 Asset management systems

The International Standards, ISO 55000:2014 and its companions, ISO 55001 and ISO 55002, were developed from the Publically Available Standard 55 (PAS 55) and are now internationally recognised standards for asset management.

An Asset Management System (AMS) is a subset of asset management and is defined as a set of interrelated or interacting elements of an organisation for coordinating activity to realise value from assets.

Our asset management policy's is the formal expression of the intention and direction of our asset management. The objectives include strategic, tactical, and operational results to be achieved. Objectives are affected by uncertainty from potential events and the resulting risk of consequences.

An elaboration of our AMS can be found throughout this document and includes descriptions of our strategies and policies, as well as discussions on our:

- asset databases
- system reliability
- condition assessment databases
- load flow analysis software
- maintenance records

- SCADA
- contract management practices with external contractors
- Alliance Agreement with NETcon.

1.5 Network and asset description

We supply electricity to over 30,600 individual connection points throughout South Canterbury. Our area of supply covers approximately 10,000 km^2 and is located on the East Coast of the South Island, between the Rangitata and Waitaki Rivers, and inland to Mount Cook on the main divide as shown in Figure 3.1. Our asset base has a replacement value of over $166 million.

Electricity is delivered to our network via seven GXPs and one embedded generator. The network delivered 806 GWh of energy and had a half hour average coincident maximum demand of 131.3 MW[3] in 2015. Energy consumption is up from the previous high of 753 GWh and a half hour average coincident maximum demand of 124.2 MW[4].

1.6 Service levels

We set service levels in conjunction with the expectations of shareholders and consumers. Reliability levels are set by the Commerce Commission under the default price-quality path.

We ask consumers for their view of the price-quality trade-offs associated with levels of service and reliability, determined by the present network configuration through our consumer survey. The findings of the survey help us gain an understanding of the level of network performance and develop options to align to consumer reliability expectations.

Previous consumer engagement across both large and industrial, and mass market consumers revealed a high level of support for keeping line charges about the same in return for similar levels of supply reliability.

1.7 Network development plans

We identify asset enhancement and development projects through consumer requests and network studies. Guidelines published by the Ministry of Economic Development determine condition and performance grades used for calculating the economic life of an asset.

The large size of new loads, such as dairy factories, makes any projections of load difficult. 5 MW of new load can be supplied with less difficulty when located nearer to existing GXPs, or where a new GXP can be easily developed. However, electricity supply is only one of the factors considered when establishing large industrial loads, with priority given to transport corridors, land use restrictions, labour force, location of resource, etc.

[3] Recorded in January 2015.
[4] Recorded in February 2014.

Table 1.3 provides the capital expenditure (Capex) forecast for the next 10 years. The figures are a summary of Appendix C. Costs are GST exclusive and in constant (real) dollar terms.

1.8 Life cycle asset management

Database hold age information on existing assets which is used as a guide for setting inspection cycles to determine asset condition. Databases and existing plans record information on major maintenance, refurbishment, and replacement of assets. The collection of further data improves the confidence level of asset condition and performance assessment. We are currently transferring hard copy plans and records into GIS with the pole assets field captured via GPS. Data entry for new and modified plant is ongoing.

A replacement of our existing legacy databases is underway with the goal of improving the efficiency, reliability, and usability of our Asset Management System.

1.9 Risk management

A risk management study based on AS/NZS 4360:2009—Risk Management and the EEA Guidelines for Security of Supply in NZ Electricity Networks has been undertaken on a qualitative basis to review all major asset categories.

Our maintenance policies include routine and special inspections to manage asset condition and ensure regulatory compliance.

1.9.1 Health and safety

We uphold excellence in health and safety management. We are committed to taking all reasonably practicable steps to ensure the work we do is safe and to prevent any harm to people or property.

Systems adopted in health and safety management are reviewed biannually. External contractors are required to disclose their health and safety management programmes, staff safety, and competency certification.

1.9.2 Emergency response and contingency planning

Development and review of emergency response and contingency planning is an integral part of:

- emergency response procedures, as covered in detail in our Emergency Preparedness Plan
- Electricity Authority approved Participant Outage Plan as required under the Electricity Governance (Security of Supply) Regulations 2008
- other contingency plans for electricity restoration (being developed in conjunction with the above).

We are a member of the Canterbury Lifelines Utility Group. The Group promotes utility resilience and is involved with the development and review of disaster recovery plans for civil defence emergencies as required under the Civil Defence Emergency Management Act 2002.

1.9.3 Environment

We are committed to acting in accordance with both the Resource Management Act 1991 and the Hazardous Substances and New Organisms Act 1996.

1.10 Evaluation of performance

We use the AMP to measure our asset management performance. Plans to maintain and improve the performance of our asset management are based on:

- improving condition based maintenance strategies
- adopting new and improved maintenance techniques and technologies
- refining the planning for new development projects to meet the need for renewal, upgrade, and extension of the network
- reviewing Asset Management System with a view to upgrading and/or replacing its existing components
- implementing the Commerce Commission AMP Review Report recommendations for achieving compliance.

1.10.1 Expenditure forecast

The following section shows our Opex and Capex for the next 10 years and includes discussion on uncertainty, variance analysis, and the use of nominal and/or real dollar terms. Our forecast for 2016–26 is provided in Table 1.3.

1.10.1.1 Management of uncertainty

The statistics related to performance against target are taken from the last financial year (2014/15) summary details to compare actual vs target results over a 12 month period, in line with existing disclosure information.

There is uncertainty in any prediction and, accordingly, our AMP contains a certain level of uncertainty. The drivers of uncertainty in our industry include several large electrical loads driven by turbulent commodity markets, international economic volatility, public policy trends, and possible generation opportunities within our network demand profile.

At the same time, management and monitoring of asset condition provides us with knowledge that we can use to appropriately plan and maintain a safe and reliable network, servicing our consumer expectations into the future.

Table 1.1 lists the certainties we attach to the timeframes covered by the AMP.

Timeframe	Residential and commercial	Large industrial	Intending generators
Year 1	Very certain	Reasonably certain	Reasonable certainty
Years 2 and 3	Certain	Some certainty	Some certainty
Years 4 to 6	Reasonably certain	Little if any certainty	Little if any certainty
Years 7 to 10	Reasonably certain	Little if any certainty	Little if any certainty

Table 1.1 AMP timeframe certainties

1.10.1.2 Use of nominal and constant dollar values

Both Capex and Opex values are expressed in constant dollar amounts (real dollars) unless otherwise specified. The values have been adjusted using an inflator of 2%[5] which approximates annual inflation for the next 10 years. Please note that Opex is decreasing in real terms. We have decided to introduce an efficiency factor equal to the approximate inflation rate. Opex is set to decrease in real terms by 2% p.a. which means that adjusting this amount by inflation each year leads to Opex values that remain static for the next 10 years (in nominal terms).

1.10.1.3 Forecast variance for 2014/15

Table 1.2 shows the variance between forecast and actual expenditure for the 2014/15 financial year. Information required by Clause 2.6.5 and Attachment A of the Information Disclosure Determination 2012 are provided in detail in the Commerce Commission Schedule 11a and 11b. A copy of the Schedule in MS Excel format is available on our website.

Variance between actual expenditure and previous year forecasts	Forecast ('$000) 2014/15	Actual ('$000) 2014/15	Variance As a %
Capital expenditure			
Customer connection	*5,259*	*4,760*	*-9%*
System growth	*2,367*	*2,869*	*+21%*
Asset replacement and renewal	*4,672*	*3,440*	*-26%*
Asset relocations	*16*	*952*	*+5,992*
Reliability, safety, and environment	*3,443*	*3,730*	*+8%*
Subtotal—capital expenditure on network assets	*15,756*	*15,751*	*-0.03%*

[5] From most recent Treasure forecasts.

Variance between actual expenditure and previous year forecasts	Forecast ('$000) 2014/15	Actual ('$000) 2014/15	Variance As a %
Operating expenditure			
Service interruptions and emergencies	*1,895*	*656*	-65%
Vegetation management	*94*	*172*	+82%
Routine and corrective maintenance and inspection	*2,764*	*3,178*	+15%
Asset replacement and renewal	*595*	*256*	-57%
Subtotal—operating expenditure on asset management	*5,348*	*4,261*	*+20%*
Total direct expenditure on asset management	***21,104***	***20,012***	***-5%***

Table 1.2 Variance between actual and forecast expenditure in 2014/15

Expenditure	Actual	Forecast										
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Capital expenditure												
Customer connection	4,760	2,850	2,850	2,800	2,800	2,750	2,350	2,300	2,300	2,300	2,250	2,300
System growth	2,869	1,660	6,582.	6,380	5,730	3,120	630	620	520	480	530	530
Asset replacement and renewal	3,440	4,163	7,091	6,477	5,353	4,987	4,882	4,992	4,780	4,720	4,720	4,720
Asset relocations	952	495	430	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Reliability, safety, and environment	3,730	1,310	1,570	1,010	790	710	710	710	675	710	710	710
Subtotal—network Capex	15,751	10,478	18,523	17,667	15,673	12,567	9,572	9,622	9,275	9,210	9,210	9,260
Capex on non-network assets	1,730	3,767	9,724	5,882	607	542	447	377	332	332	467	422
Total Capex	*17,481*	*14,245*	*28,247*	*23,549*	*16,280*	*13,109*	*10,019*	*9,999*	*9,607*	*9,542*	*9,677*	*9,682*
Operational expenditure												
Service interruptions and emergencies	656	1,450	1,362	1,342	1,322	1,303	1,283	1,264	1,246	1,252	1,258	1,264
Vegetation management	172	500	516	508	501	493	486	479	472	474	477	479
Routine and corrective maintenance	3,178	2,801	3,036	2,991	2,947	2,903	2,860	2,818	2,776	2,790	2,804	2,818
Asset replacement and renewal	256	598	355	350	345	339	334	329	325	326	328	329
Subtotal—network Opex	4,261	5,348	5,269	5,191	5,114	5,039	4,964	4,891	4,819	4,842	4,866	4,890
Opex on non-network assets	9,561	13,462	16,680	18,626	18,516	17,613	16,703	15,228	13,942	13,186	12,914	12,801
Total Opex	*13,822*	*18,810*	21,949	23,817	23,630	22,652	21,667	20,119	18,760	18,029	17,780	17,691
Total expenditure on assets	**31,303**	**33,055**	**50,196**	**47,366**	**39,910**	**35,761**	**31,686**	**30,118**	**28,368**	**27,571**	**27,457**	**27,373**

Table 1.3 AMP forecast expenditure 2016 to 2026

Note: Our overhead to underground expenditure is within the asset replacement renewal budget.

2. BUILDING BLOCKS OF THE ASSET MANAGEMENT PLAN

2.1 Introduction

Chapter 2 details the background and objectives of our AMP by describing our:

- strategic goals and objectives, and development
- key planning documents
- asset management systems and processes
- accountabilities of asset management

2.2 Purpose of the AMP

The purpose of our AMP is to provide a governance and management framework to ensure that we:

- set service levels and meet our stakeholder expectations and regulatory requirements
- understand what levels of network capacity, reliability, and security of supply will be required now and into the future
- have robust and transparent processes in place for managing all phases of the asset life cycle from the proposal phase to decommissioning
- identify risks and have proper processes in place to mitigate risk
- make appropriate provision for funding the asset life cycle stages
- make informed decisions with systematic and structured framework at each level within the business
- have robust information on asset location, age, and condition
- comply with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 ,in particular Attachment A—
Asset Management Plans.

Our AMP is a description of the policies, strategies, plans, and resources we use to manage our assets, rather than a detailed description of those assets.

2.3 Mission statement

Our mission statement is:

"To ensure continuing commercial success by providing safe, reliable, and efficient energy delivery and infrastructure services."

We achieve our Mission Statement by:

- providing safe, reliable, efficient, and cost effective energy delivery that promotes efficient and sustainable energy use

- encouraging the use of and utilising water resources to support the production and consumption of electricity
- providing asset management services.

2.4 Development of strategic goals and objectives

Our strategic goals and objectives are developed through communication with our stakeholders and are for:

- shareholders—to maximise the value of the company
- consumers—to provide safe, efficient, and reliable delivery of energy and services
- regulators—to promote energy efficiency and the effective utilisation of our network
- staff—to be part of a company for which they are proud to work
- public at large—to be a law abiding, publically and socially responsible company.

2.4.1 Stakeholder engagement

Stakeholder engagement is an essential part of our decision making process. Communicating our AMP to stakeholders and inviting their feedback is one way in which we engage.

Table 2.1 describes how we take account of our stakeholders' interests.

Stakeholder	Identification and management of expectations	Key interests
Shareholders: Lines Trust South Canterbury and district councils	Through approval and/or amendment of the Statement of Corporate Intent (SCI). We have regular meetings between directors and the trustees.	• Health and safety • Financial return • Service quality • Good governance
Retailers	Regular meetings and consulations with retailers.	• Line charges • Quality of supply • Low transaction costs • Compliance
Electricity consumers	Most communications are done through retailers as consumers are contracted to retailers rather than us. We engage with industry groups through representatives on an informal basis.	• Health and safety • Line charges • Quality of supply • Compliance
Employees and contractors	Regular staff briefings and contractor meetings. Normal course of business interactions.	• Health and safety • Training and development • Compliance • Service quality

Stakeholder	Identification and management of expectations	Key interests
Public, iwi, and landowners	Informal talks, media presentations/information disseminations, and local advertising and sponsorship. Feedback from the Trust's public meetings.	• Health and safety • Respect for cultural and environmental issues • Land access
Regulators: Commerce Commision and Electricity Authourity	We receive regular bulletins from the regulators. We submit on the various consultation papers and participate through industry working groups.	• Regulated return • Pricing methodologies • Quality of supply • Compliance
Local councils	Regular meetings to discuss planning. We receive newsletters and use the newsletters to communicate information (e.g. planned outages) to the public.	• Environmental compliance • District and regional plans
Embedded networks	Formally as necessary to discuss common issues (assets on council land or CDEMG).	• Health and safety • Financial return • ACOT • Quality of supply • Compliance
Transpower	Meet and discuss development needs and opprtunities as these arise. Participate in industry working groups	• Health and safety • GXP loads • Quality of supply • Compliance
Embedded generators	We receive information from our embedded generators. We submit on consulation papers and provide feedback through industry working groups.	• Health and safety • Financial return • Price • Quality of supply • Compliance

Table 2.1 Identification and management of stakeholder expectations

2.4.1.1 Accommodating common stakeholder interest

Table 2.2 describes how we accommodate common stakeholder interests.

Interest	Description	How we accommodate interests
Viability	Viability is necessary to ensure that stakeholders have sufficient reason to keep investing.	We will accommodate our stakeholders' needs for long-term viability by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return.

Interest	Description	How we accommodate interests
Price	Price is a key means signalling underlying costs. Getting prices wrong has economic implications for both us and our stakeholders.	Failure to recover sufficient revenue to fund reliable assets will negatively impact consumers' activities. Under the Electricity Authority's pricing principles prices are expected to be cost effective. However, our price increases are capped by the default price-quality path administered by the Commerce Commission. Substantial new investment may require us to apply to the Commerce Commission for a customised price-quality path if the default price-quality path is unable to balance security, capacity, reliability, and return on investment.
Supply quality	Continuity, restoration, maintaining voltage, and reducing voltage drops is essential to maintaining quality of supply to our consumers.	We will accommodate our stakeholders' needs for supply quality by focusing resources on quality, continuity, and restoration. We will endeavour to comply with the quality standards under the default price-quality path during each regulatory year.
Safety	Staff, contractors, and the public at large must be able to move around and work on our network safely.	We will keep the public at large 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 securely earthed. We will ensure the safety of our staff and contractors by providing all necessary equipment, continuously improving safe work practices, and ensuring that workers are stood down in unsafe conditions.
Compliance	We must comply with many statutory requirements ranging from safety to the annual disclosure of information.	We will to all extent practicable comply with our regulatory obligations. Where we suspect non-compliance we will document and report the causes to the applicable regulatory body and implement appropriate corrective action.
Efficient operation	Operating the business and managing costs efficiently.	We are always looking to improve our asset management systems to make our operations more efficient. During 2016 we intend to scope asset management systems that more effectively record our assets.

Table 2.2 Accommodating stakeholder interests

2.4.1.2 Managing conflicting interests

Conflicting stakeholder interests are managed by taking account of the hierarchy of priorities:

- safety
- reliability
- efficiency
- compliance
- financial return.

2.5 Key planning documents

Our key planning documents set out the actions needed to achieve our strategic goals and objectives and include the:

- Statement of Corporate Intent
- Strategic Management Plan
- Asset Management Plan
- Annual Works Plan
- Alpine Energy Safety Management System and related documents.

Figure 2.1 shows the interaction of our key planning documents with our strategic goals and objectives.

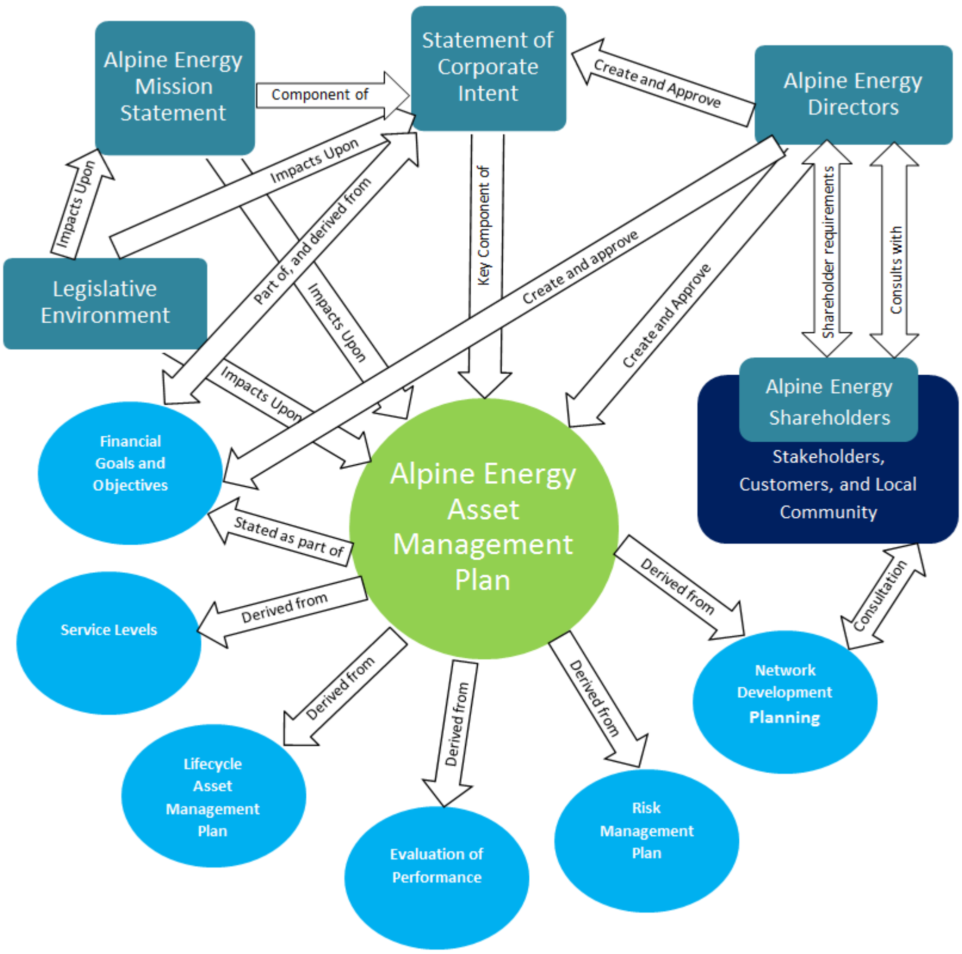


Figure 2.1 Interaction of key processes and entities

2.5.1 Statement of Corporate Intent

Our Statement of Corporate Intent (SCI) sets out our strategy for delivering our goals and objectives for the next three years (i.e. April 2016 to March 2019) by:

- stating our mission, vision, values, goals and objectives
- detailing the nature and scope of activities that we will be undertaking
- maintaining a 50% proprietorship ratio
- committing to have accounting policies that support compliances
- setting financial and operational performance targets
- summarising our dividend distribution policy
- specifying the information to be provided to shareholders
- outlining procedures for the acquisition of interests in other companies or organisations
- disclosing transaction details.

2.5.2 Asset management strategy

Our asset management strategy describes the asset management processes that we follow to achieve our strategic goals and objectives. At present, our strategy is not a formal document; instead strategy is inherent throughout the AMP. Please see Section 8.3—Continuous improvements to our asset management system for details on how we intend to formalise an asset management strategy.

2.5.3 Annual works plan

Our annual works plan ensures that our activities and projects are prioritised and aligned with our goals and objectives. It reflects on existing projects and adjusts for recent commercial and operational issues, while contributing to long term planning. The works plan also details how a project should be implemented. The projects in the annual works plan are described in this AMP.

2.5.4 Safety Management System

The Safety Management System (SMS) is a regulatory requirement which incorporates the *Health and Safety Management System* and the *Public and Safety Management System.* It is further described in Chapter 7—RISK MANAGEMENT. The interaction of our AMP with our SMS is shown in Figure 7.1.

2.6 Planning assumptions

Our planning makest assumptions and takes account of uncertainty around the social, economic, and political environment in which we work. Our assumptions are listed in Section 5.2.1.4—Planning assumptions and impact of uncertainty.

2.7 Asset management systems and processes

Our asset management systems (AMS) and processes are both formal and informal methods that we use to manage asset data and information to achieve our strategic goals and objectives.

The information disclosure regulatory obligations[6] require us to provide information on the state of our asset maturity, including our systems and processes via the AMMAT. Our self-assessment has identified that our systems and processes for life cycle asset management need to be further established and developed. A summary of our self-assessment can be found in Chapter 8—ASSET MANAGEMENT MATURITY ASSESSMENT more detail can be found in Schedule 13.

2.7.1 Key systems and processes

The present state of our AMS and processes is described below. Further details on our asset life cycle management can be found in Chapter 6—LIFE CYCLE ASSET MANAGEMENT PLANNING. For information on how we are enhancing our systems and processes, please see Chapter 8—ASSET MANAGEMENT MATURITY ASSESSMENT.

2.7.1.1 Information technology for asset management

ICT systems specific to asset management are described in Table 2.3.

System	Tasks/data provided	Linkages
GIS	Network asset data and location of all network assets.	Links to AMS and ICP database. The ICP database updates address information in GIS.
AMS	AMS database including serial numbers, maintenance data, current ratings, voltage levels, etc.	Links to GIS
ICP database	Metering asset database. Consumer connection point information	Links to GIS
SCADA	Substation data and control	Stand alone
Nimbus	Accounting and asset register	Stand alone

Table 2.3 Information technology databases for asset management

[6] Commerce Commission's *Electricity Distribution Information Disclosure Determination 2012—(Consolidated in 2015)*, 24 March 2015 (IDD2015).

2.7.1.2 Operating processes and systems

To ensure safety to personnel, public, and plant, our operating systems and processes are based on industry standard procedures. The EEA Safety Manual—*Electricity Industry (SM-EI)* informs our internal operating procedures and is used to share knowledge with other network companies on safe working practices, network control, and operating procedures.

2.7.1.3 Maintenance processes and system

Our maintenance processes are based on manufacturer specifications and maintenance requirements. Generally, asset condition is assessed on age and physical condition. The assessment determines whether an asset is replaced, refurbished, maintained, or deemed to be in good condition and left till the next scheduled inspection.

Our present maintenance processes and systems are a combination of manual and paper-based systems (e.g. maintenance and test cards, test reports, and spreadsheet schedules) and off-the-shelf and bespoke systems such as Nimbus, AMS, and GIS database. We are scoping specific purpose-based and integrated asset maintenance software to make our current practices more efficient.

Routine maintenance is undertaken by our preferred contractor NETcon, which is a wholly owned subsidiary of the Alpine Energy Limited. NETcon uses, holds, and maintains detailed maintenance schedules for our substations, and plant.

Project based maintenance, such as major refurbishment and renewal work, is managed as projects within the context of our overall Capex programme for the year.

2.7.1.4 Renewal processes and systems

When the assessment indicates that an existing asset is at risk, the item is scheduled for renewal. As assets often age or exhibit deterioration at different rates, a decision often needs to be made in regard to replacing an entire series or individual assets on successive visits. The economics of each approach is evaluated on a case-by-case basis and accounts for the risk of extending the assets' service life.

Overhead lines are routinely inspected and the remaining strength of the support pole is assessed to determine end of life to ensure replacement before failure. Substation and plant inspections are undertaken either by NETcon as part of the routine maintenance programme or as part of a condition assessment inspection by our asset group. The information generated by the inspections is collated, reviewed, assessed, and used to inform our planning decisions.

2.7.1.5 Processes and systems for upgrades or extensions

Load growth can reduce capacity headroom. Our forecasting and network modelling tools indicate when feeders are likely to need support from capacitors or regulators, to be upgraded with larger conductors, or whether the zone substation transformer capacity needs to be increased.

Network modelling software programs, such as ETap[7], are a valuable forecasting tool when upsizing may be required due to substation feeder voltage performance limits being reached. For further information, please see Section 5.2—The planning process a the strategic level.

2.7.1.6 Reliability enhancement processes and systems

We review faults and investigate the causes to determine how the impact of interruptions can be reduced or avoided. Improving security of supply for larger loads is a well understood approach and is documented in EEA Guideline *Security of Supply Standards* (EEA Standards Guide). As well using the EEA Guideline, we take our network conditions into account when evaluating risk. We adjust for:

- local geography
- demography
- distribution of load types
- weather
- earthquake risk
- contractor and technical resource availability
- asset selection.

If applied mechanistically, the adjustments produce different security of supply levels for individual sites or installations to those produced by the EEA Guide.

Each year we review our 10 worst performing feeders to determine supply failure mode and a suitable remedy to reduce reoccurrence. Remedies include:

- building a new feeder
- splitting urban areas from rural to avoid remote rural faults affecting urban areas
- installing additional reclosers to reduce the number of consumers affected by a single fault.

2.7.1.7 Customer connection processes and systems

Customer applications for connection to our network are processed through a standard system, with contractor quotes used to determine connection price.

2.8 Accountabilities for asset management

Figure 2.2 shows our asset management accountabilities and mechanisms.

2.8.1 Accountability at ownership level

We are 100% owned by the South Canterbury community—the community we serve. Our shareholders are:

[7] ETap provides electrical power system modeling, design, analysis, optimization, control, operation, and automation software more information can be found on ETaps' website at http://etap.com/

- Timaru District Council—47.5%
- Lines Trust South Canterbury—40%
- Waimate District Council—7.54%
- Mackenzie District Council—4.96%.

The Lines Trust South Canterbury is subject to an election process. The Trust Deed holds all trustees collectively accountable. The three district councils are ultimately accountable to ratepayers through the local body election process and to the Minister of Local Government under the *Local Government Act 2002*.

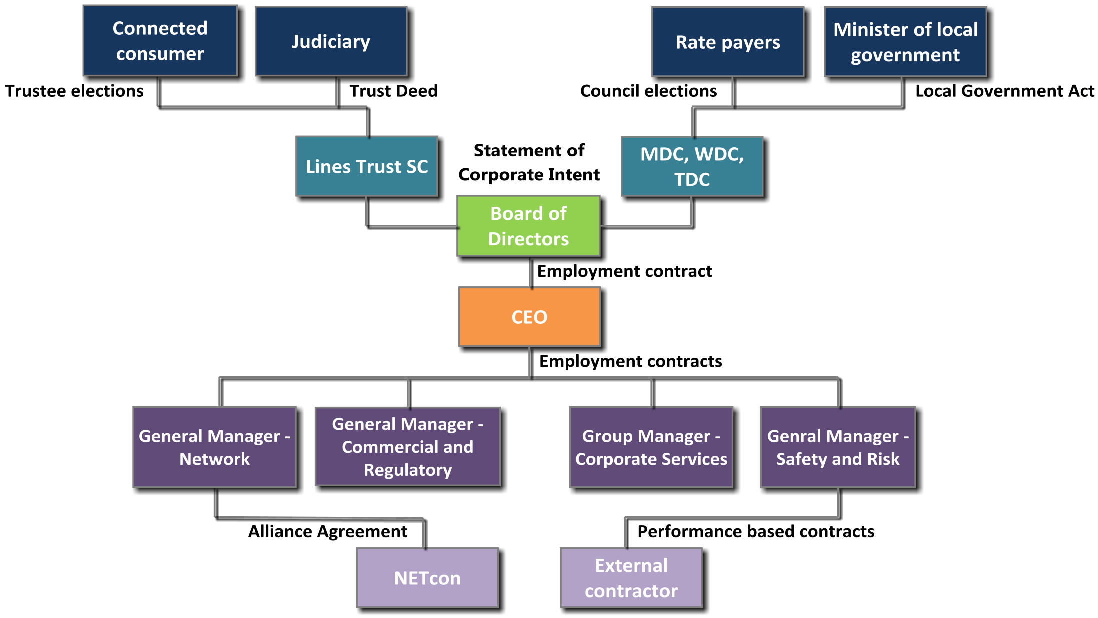


Figure 2.2 Accountabilities for asset management

2.8.2 Accountability at governance level

Our directors are accountable to our shareholders through our SCI. We presently have five directors who are appointed as follows:

- two directors appointed by the Lines Trust South Canterbury
- two directors appointed by the TDC
- one director appointed jointly by the MDC and WDC.

2.8.3 Accountability at executive level

Our Chief Executive Officer is accountable to the directors through an employment contract that sets out the leadership of the organisation and key business performance indicators to meet SCI goals and objectives.

2.8.4 Accountability at management level

Accountability for asset management ultimately lies with our General Manager—Network.

As part of our move towards compliance with ISO 55000, we have restructured our Network Department. The new structure is designed to support company strategy and goals, the asset management framework, legislative and regulatory compliance, our Alliance Charter, workload diversity, quantity, and compliance.

We aim to achieve our goals through the development of a comprehensive asset strategy and delivery framework; documentation, controls, and review; systems and information management; communication and participation; and structure, capability, and authority.

In order to implement the new structure, the following positions have been created in the Network Department.

Network Delivery Manger—is accountable for leading our design and project management team in planning all designs and project manage the delivery of the annual works plan according to industry and our standards; and for achieving cost effective and safe solutions to network development and refurbishment opportunities.

Customer Service Manager—is accountable for leading the new connections team to:

- manage new connections and extensions and distributed generation applications
- design, project and contract management related to these connections
- ensure all metering obligations are met in accordance with the Electricity Industry Participation Code 2010.

Maintenance and Asset Information Manger—is accountable for leading our asset and plant maintenance team, and the implementation, operation, and management of our asset information system; and for leading the maintenance, GIS, and CAD teams to achieve company goals and objectives.

Operations Manager—is accountable for ensuring the safe and reliable operation of the network and for the planning, control, and execution of all testing, construction and maintenance work on the network, including vegetation management.

Planning Manager—is accountable for overseeing the network development team through short and long term planning of the network and associated deliverables.

Through close team collaboration between the operations, asset, and network managers, we balance budgets and coordinate maintenance, renewal, and operation of the asset portfolio as directed under the framework of the AMP and business target strategies.

Figure 2.3 shows our accountabilities at network level.

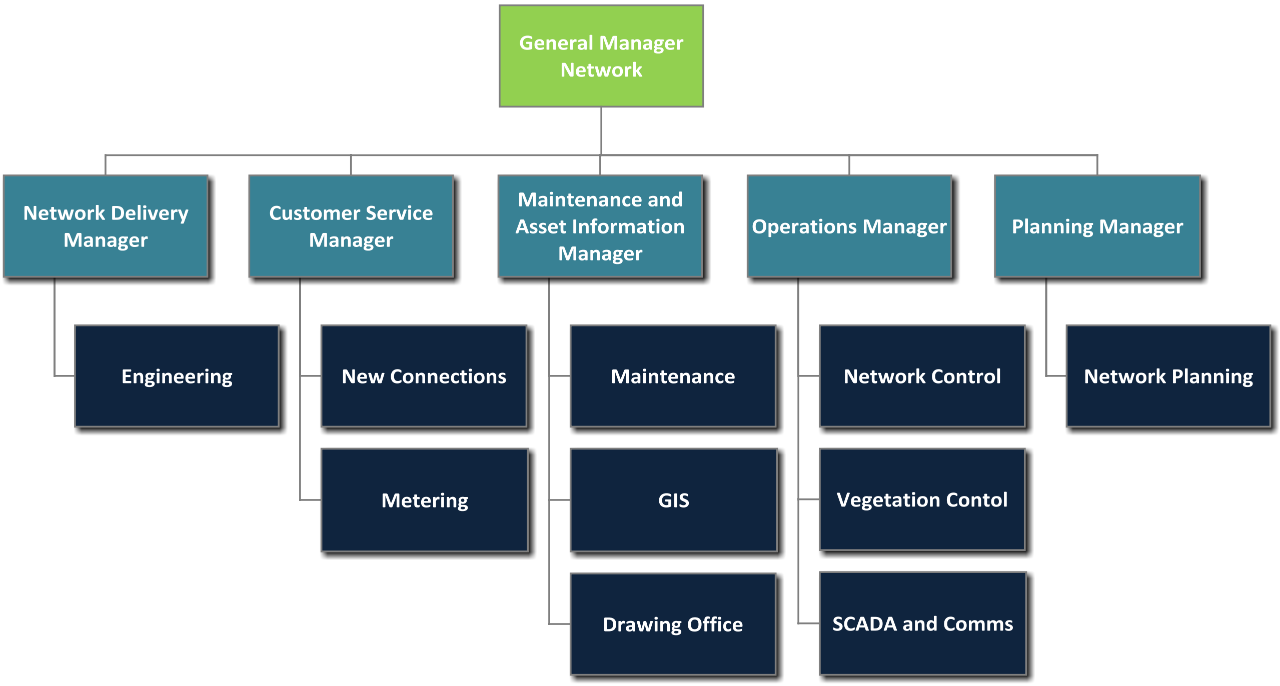


Figure 2.3 Accountabilities for asset management at network level

2.8.5 Accountability of our contractors

2.8.5.1 Contractor accountability

All contractors are obliged to comply with our policies and standards, including:

- Risk Management
- Network Authorisation and Competency
- Personal Protective Equipment
- Drugs and Alcohol
- Health and Safety Requirements for Network Contractors

NETcon is accountable through the Alliance Agreement as our preferred contractor for capital and maintenance services on our network. NETcon has approximately 100 staff who provide a scalable resource for us during adverse weather events, large projects, and assist us in our duties under the mutual is agreements we have with other networks.

External contractors are accountable through performance based contracts.

2.8.5.2 Service contract negotiations

We use NETcon for the majority of the network's operations, maintenance, renewal, and upgrade work, subject to the Alliance Agreement.

Project work required for extensions, renewals, and upgrades to the network is subject to quotations before jobs are awarded. New connection work is subject to competitive quotes from other contractors, as are certain large line jobs.

Specialist jobs are undertaken by external contractors who quote to a scope or specification on a competitive basis. For example, some engineering design, civil design, onstruction associated with new zone substations, major lines, certain types of communications systems work, and specialist inspection and training services.

2.8.6 Key reporting lines

The Board of Directors governs our business. The Board has delegated overall responsibility for the management of our assets to the CEO.

Our Board receives a monthly report from management outlining our performance against key indicators, including:

- health and safety
- financial
- operational
- corporate
- regulatory
- progress on the annual plan of maintenance
- capital activities
- SAIDI and SAIFI
- progress on significant (over $300, 000) Capex projects.

Board meetings are typically held every two months.

The budget detail and review of the AMP is driven by the network managers.

Projects are approved by the Board of Directors through the AMP and Capex instruments.

2.8.6.1 Network Group

The Network Group consists of five teams:

- Planning
- Delivery
- Maintenance and Asset Information
- Customer Service
- Operations.

Planning

The Planning Team is responsible for the strategic planning for new assets required to meet growth and other changing needs of our network through detailed planning and design of new capital plant assets.

Network Delivery

The Network Delivery Team is responsible for the acquiring, installing, and commissioning new capital plant assets, as designed by the Planning Team, to meet the requirements of our growing network.

Maintenance and Asset Information

The Asset Maintenance and Information Team is responsible for the maintenance of all existing primary and secondary electrical assets. The Team's responsibility extends to the collection and management of asset data, as well as the creation and maintenance of cable diagrams

Customer Service

The Customer Service Team is responsible for processing all new connection and distributed generation applications, as well technical and administrative metering functions. The Team also looks after all retailer service requests such as disconnects, reconnects, site visits, etc.

Operations

The Operations Team collectively provides planning, operating, and management of fault response services to ensure high levels of consumer service are maintained throughout the region. The Team is also responsible for switching, ensuring that all work on the network is done safely and with as little supply interruption as possible.

2.8.6.2 Corporate Services Department

The Corporate Services Department manages the financial, human resource, accounting, and ICT system functions. The department provides contract and financial analysis, and expertise on items outside the network's routine work.

2.8.6.3 Commercial and Regulatory Department

The Commercial and Regulatory Department ensures that we are aware of our regulatory obligations in accordance with various legislative instruments under which we operate. The department is responsible for billing and registry functions, and provides commercial and business development support and expertise.

2.8.6.4 Compliance and Training Department

The Compliance and Training Department ensures our compliance with: health and safety legislation, industry regulations, staff and contractor training, as well as civil defence, lifeline utility and related matters. The Department ensures that all contractors working on our network are authorised to access the network and complete work to the required standards. The Department champions our health and safety culture through the promotion of best practice and continuous improvement of safety on the network.

3. NETWORK ASSETS

3.1 Introduction

Chapter 3 describes the key drivers that influence demand on our network and the design and configuration of our assets.

3.2 An overview of our area of operations

Our network stretches over 10,000 km^2, bounded between the Rangitata River in the north and the Waitaki River in the south. To the west, our supply extends to the southern divide as far as Mt Cook Village, while the coast is the natural eastern boundary, as shown in Figure 3.1 [8]. The three district councils—MDC, TDC, and WDC—provide infrastructure assets across the area.

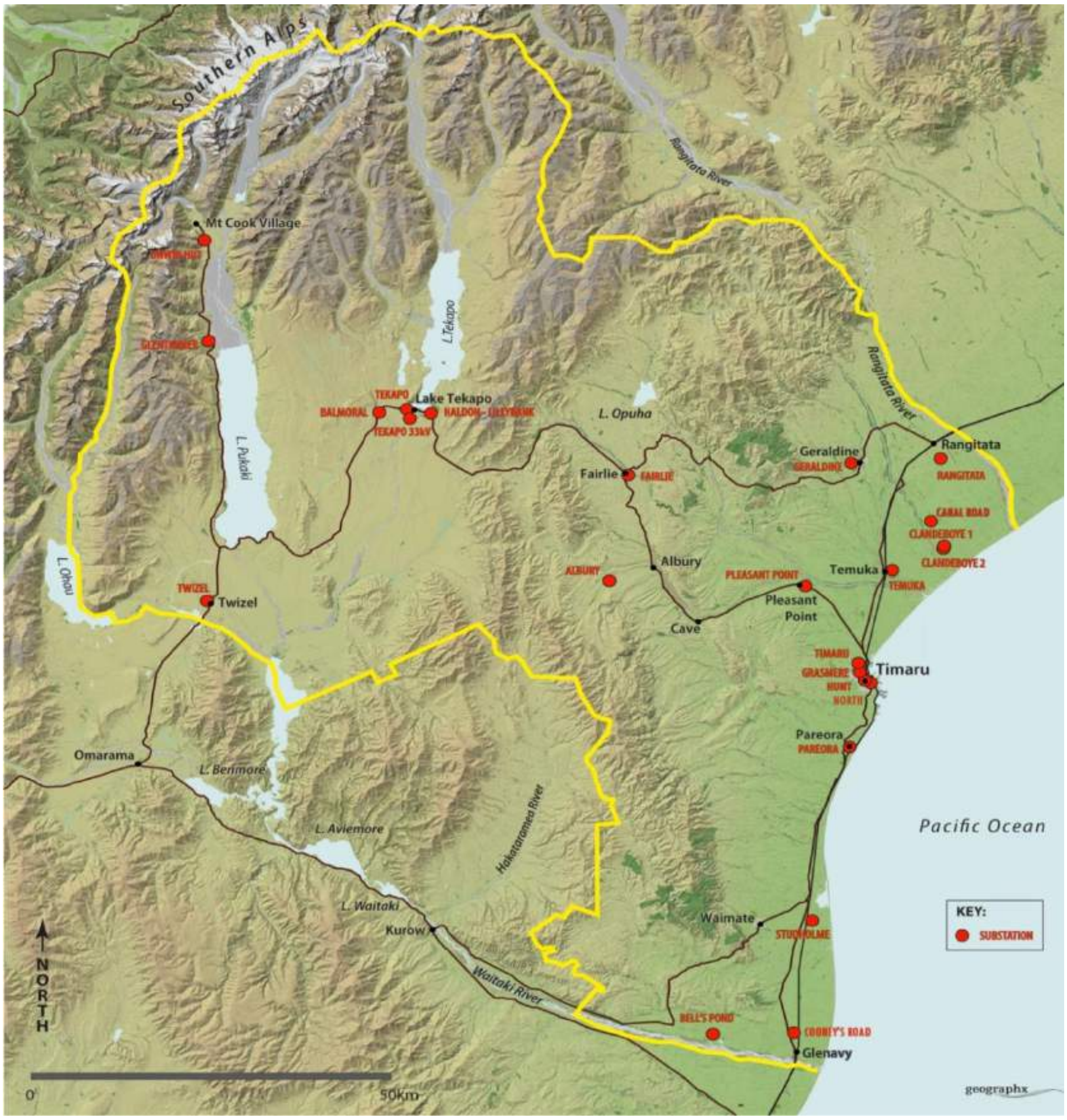


Figure 3.1 Our area of supply

[8] The Hakateramea and high country bounding on Avienmore and Benmore lakes are part of Network Waitaki Limited (NWL).

The 2013 population statistics for the three council districts are listed in Table 3.1.

District\census	1996	2006	2013 census	Growth: 1996-2013	Annual growth
Timaru	42,633	42,870	43,932	3.05%	0.18%
Mackenzie	4,077	3,804	4,158	1.98%	0.12%
Waimate	7,620	7,206	7,536	-1.1%	-0.06%
Total	54,330	53,880	55,626	2.4%	0.14%

Table 3.1 Population growth (source: Statistics NZ)

The average annual growth in population is small and occurs mostly in urban areas. Most of the load growth on our network comes from the irrigation requirements of dairy farming.

Timaru

The majority of our 30,576 consumers live in the Timaru area on the east coast, with about 13,500 living in or near Timaru City. Timaru is the hub of South Canterbury, connecting the road networks west, north, and south. The city serves a CBD, a main residential population, and a range of industries and commercial businesses including two meat processing plants; a container, timber, and bulk cement port; a brewery; wool scour; and food processing plants. The majority of load growth in the city comes from industrial development.

The second largest population group lives at Temuka, 20 km north of Timaru. Temuka is surrounded by plains used for farming. Our largest customer, Fonterra (30 kW instantaneous demand), operates a milk processing factory at Clandeboy and continues to stimulate growth in the local economy. The areas north of Temuka, up to the Rangitata River, continue to see extensive development in cropping and dairying with supporting irrigation.

Mackenzie

The MacKenzie area is situated 40 km west of Timaru and extends to the southern divide. The Mackenzie is an alpine area, requiring assets to be strengthened for snow and wind loading. The MacKenzie District Council (MDC) is headquartered in Fairlie and administers the Albury, Tekapo, Twizel, and Mt Cook townships. Fairlie is a farming support town, while Tekapo, Twizel, and Mt Cook are tourist and holiday home destinations with growing subdivision and hotel accommodation developments.

Twizel is the operational centre for Meridian Energy's electricity generation assets. Genesis Energy has generation assets at Tekapo and Pukaki. Growth is predicted to increase in the Tekapo and Twizel areas, with plans for further irrigation development in the Twizel district, and a new retail development in the Tekapo Township planned for 2015 onwards.

Waimate

The Waimate area is administered by the WDC and is the southernmost area of South Canterbury. Sizeable irrigation development has occurred here, serving to stanilise the population of the Waimate township. A new irrigation scheme, Waihaop Downs Stage 1, is presently under construction.

3.2.1 Load growth on our network

Load growth slowed and plateaued in some areas following the international credit crisis in 2009, but has been increasing since early 2013.

The total energy consumed in 2014/15 was 806 GWh. Annula energy consumed varies from year to year based on wet or dry irrigation seasons, and severe or mild winters.

The anytime maximum demand (AMD) is presently 131.1 MW[9]. Growth in AMD has been approximately 3.35% per year over the last 18 years.

3.2.2 Significant economic and environmental influences

Economic activity in our area of operation, particularly activity in the primary industry sector, strongly influences the configuration of our network.

There has been significant growth in dairy farming and processing, bringing an increased demand for load for irrigation purposes, along with the need to supply the recently commissioned Oceania Dairy Limited (ODL) dairy factory in Glenavy and the established Fonterra dairy plants in Studholme and Clandeboye. Other large industrial customers, such as the Alliance Smithfield and Silver Fern meat processing plants, have a substantial effect on the network. Overall, the viability of arable farming and the availability of water have a significant impact on the local economy and the configuration of our network.

The port operations at PrimePort Timaru[10] continue to be an important part of the region's economy. The recent change in management of the port has seen resurgence in local container operations. In addition, Holcim started its operations at PrimePort Timaru (a partner of the Port of Tauranga) for the movement of its bulk cement in the South Island and beyond in December 2015.

3.2.2.1 Peak loading

Irrigation load is the main cause of summer peak loading at all the GXPs except TIM, TKA, and TWZ although the increase in irrigation demand is tempered by local environmental restrictions on water use and nitrogen application.

Winter peak loading occurs mainly at TIM and TKA GXPs although other areas, like Fairlie and Geraldine, also have significant demand for load during the winter months as temperatures can fall below -10°C.

[9] As at December 2014
[10] More information about PrimePort Timaru can be found at www.primeport.co.nz.

Winter load demand everywhere may rise due to more regulation around air quality and particulate matter, restricting the use of fires for heating and placing greater demand on the network to service other forms of heating, such as heat pumps.

3.2.2.2 Large customers

We consider large consumers that have a significant impact on network operations or asset management priorities to be customers that we have a direct contractual agreement with. Our top five customers, based on demand, are described in Table 3.2. Holcim, the most recent of our directly contracted customers, is shown in Figure 3.2.

Fonterra Co-Operative Group Limited	
Location	Clandeboye 1 and Clandeboye 2, Milford
Dedicated assets	CD1 - One underground 33 kV cable circuit from TMK GXP, plus one overhead 33 kV line circuit from TMK GXP, 33/11 kV zone substation, including 2x 20 MVA OLTC transformers and 15 cubicle 11 kV switchboard, plus many 11/0.4 kV distribution substations with transformers and RMUs. CD2 - One underground 33 kV cable circuit from TMK GXP, plus one overhead 33 kV line circuit from TMK GXP, 33/11 kV zone substation, including 2 x 25 MVA OLTC transformers and 12 cubicle 11 kV switchboard, plus many 11/0.4 kV distribution substations with transformers and RMUs.
Impact on the network	Considerable
Alliance Smithfield	
Location	Smithfield, Timaru
Dedicated assets	11 kV connection to customer owned switchgear. Normally selected to one feeder with a second for backup.
Impact on the network	Medium, GXP capacity can be used by other growing loads.
Fonterra Co-Operative Group Limited	
Location	Studholme
Dedicated assets	10x 11 kV RMUs (one switching and two spare). 7x 11/0.4 kV distribution transformers. Supply teed off two of our rural lines, line reclosers fitted after tee offs.
Impact on the network	Significant, but transformers and switchgear could be reused over time elsewhere in the network.

Oceania Dairy Ltd	
Location	Glenavy
Dedicated assets	33 kV switching bay at BPD. 33 kV bonded double circuit line (built in 110 kV construction) from BPD to CNR substation. 33/11 kV CNR zone substation with one power transformer. Eight cubicle 11 kV switchboard. 15x 11 kV RMUs (3 future). 12x 11/0.4 kV distribution transformers.
Impact on the network	Significant, but transformers and switchgear could be reused over time elsewhere in the network.
Holcim	
Location	Port of Timaru
Dedicated assets	3x 11 kV RMUs, 3x 1.5 MVA transformers, 1x 11 kV supply to the ship loader. At the site, we also created a network tie between Grassmere substation and North St substation.
Impact on the network	Significant

Table 3.2 Our directly contracted customers

Figure 3.2 Holcim's inflatable dome

3.2.3 Network energy and demand characteristics

Key energy and demand figures for our seven GXP areas for the year ending 31 March 2015 are detailed in Table 3.3.

GXP area	Asset utilisation (GWh)	Max demand[11] (MW)	Load factor (F=W/(Pmax.T))	Transpower capacity utilisation (Pmax/Ptxfr)	Long-term growth trend (based on 18 year historical)
ABY	10.92	4.32	0.29	86%	2.12%
BPD	39.59	10.28	0.44	51%	14.91%*
STU	68.82	13.22	0.59	60%	3.54%*
TKA	17.75	3.75	0.54	37%	3.89%
TMK	283.95	54.11	0.60	53%	6.68%
TIM	359.92	62.48	0.66	66%	0.73%
TWZ[12]	12.780	3.18	0.46	8%$_2$	3.27%
Exported	-13.43				
Generation	25.46				
Total	**805.76**	**151.34**			**3.31%**

Table 3.3 GXP energy and maximum demand

The maximum demand and the TIM and TMK GXPs has plateaued over the last six years. Forecast growth in demand predicts a maximum demand increase to 136 MW in 2015/16 and to 160 MW in 2020/21, assuming a constant growth rate of 3.31% over a six-year period. More information on our demand forecasts can be found in Schedule 12c: Demand Forecast at Appendix F.

3.3 Network configuration

Section 3.3 describes our network assets in relation to Transpower GXPs. A brief summary is given for GXPs, zone substations, and sub-transmission assets (more detail can be found in the AMP—Major Assets). A summary of the condition of our network assets is provided in Commerce Commission's Schedule 12A: Asset Condition (a copy of the schedule is available on our website).

Please note that, on limited occasions, network asset age profile data is inconsistent[13]. We currently address inconsistencies on a case-by-case basis. We intend to address the

[11] The individual GXP MD figures are not coincident with each other or the total system MD.
[12] The TWZ GXP is shared by two other customers whose asset utilisation is not shown here.

inconsistencies in the long term through the enhancement of our AMS ICT systems. For more information on the enhancement of our AMS, please see Section 8.3—Continuous improvements to our asset management system.

3.3.1 Historical constraints on our network

Our network is comprised of two historically distinct line businesses which were merged in 1993—the Timaru Municipal Electricity Department (MED) and the South Canterbury Electric Power Board (SCEPB). The existing asset configuration comprises lines through a corridor in an SCEPB area to supply an encircled MED area (similar to cities like Invercargill, Palmerston North, Hamilton, and Nelson), and has three key characteristics.

- The compact MED is supplied at 11 kV from TIM GXP.
- The difference in phase angle between the 110/11 kV supply in the Timaru metro area and the 110/33 kV supply in the adjacent Temuka and Geraldine rural areas means that the areas cannot be easily and safely meshed to improve security of supply.
- There are areas of supply at the boundary of the historical areas that can be improved by greater integration of the assets of the two legacy networks (e.g. by upgrading 11 kV lines and cables, and introducing additional, or upgraded, points of connection between the two networks).

3.3.2 Bulk supply configuration

A summary of GXP asset information is provided below. Detailed information on Transpower GXPs can be found in the AMP-Major Assets.

Figure 3.3 shows the GXP configuration from a transmission perspective and Table 3.4 summarises key GXP details.

[13] For example, the age profiles of 11 kV CBs, ripple plant, and LV cables are presently under review.

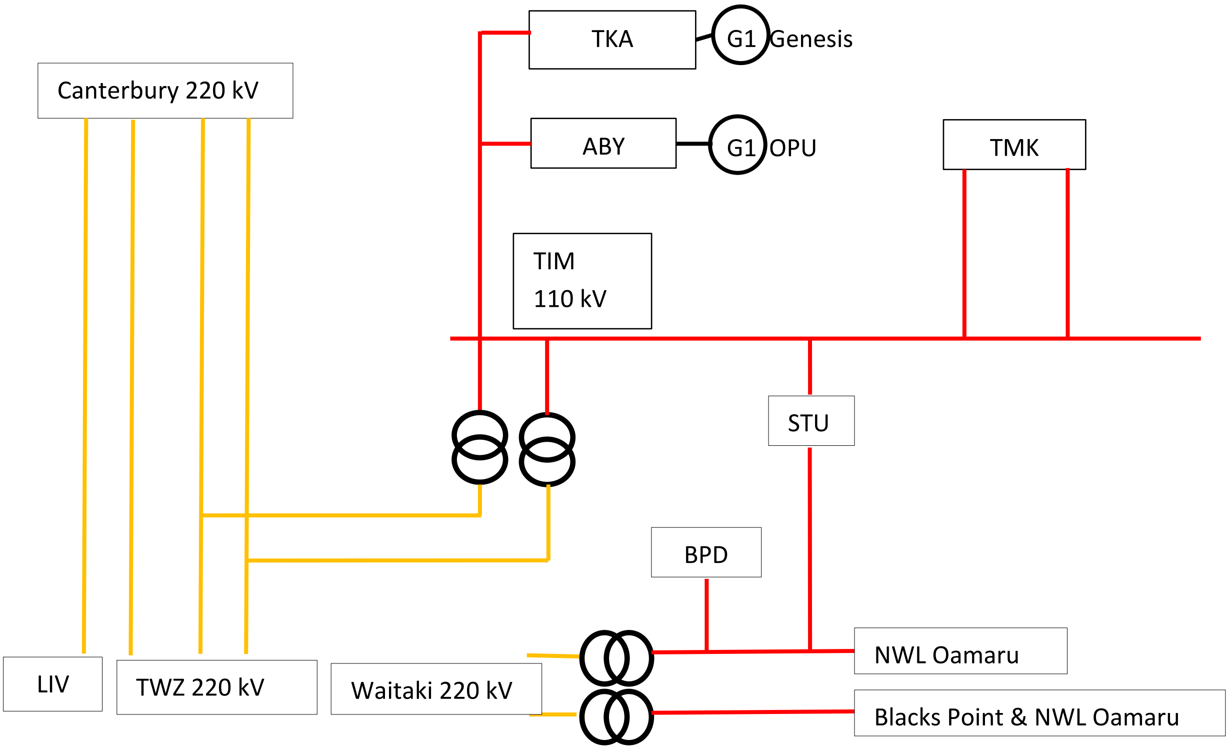


Figure 3.3 Transpower GXPs

Key energy and demand figures of our seven GXP areas for the year ending 31 March 2015 are detailed in Table 3.4.

GXP	GXP voltage(s), transmission	GXP upply voltage to	GXP capacity*	GXP (N-1) capacity	Demand	Embedded generation (OPU dam)
ABY	110 kV	11 kV	6.3 MVA	0	4.3 MW	7.2 MW
BPD	110 kV	110 kV	20 MVA	0	10.3 MW	
STU	110 kV	11 kV	24 MVA	12 MVA	13.2 MW	
TKA	110 kV	33 kV	6.7 MVA	0	3.8 MW	
TMK	110 kV	33 kV	122 MVA	61 MVA	54.1 MW	
TIM	220 kV, 110 kV	11 kV	141 MVA	94 MVA	62.5 MW	
TWZ	220 kV	33 kV	40 MVA	20 MVA	3.2 MW	

Table 3.4 GXP and related substation configuration as at 31 March 2015

3.3.3 Assets by category

Our assets can be grouped as detailed in Figure 3.4.

Sub-transmission circuits

- 33 kV
- Including Timaru CBD 11 kV sub-transmission cables.

Zone substations

- 33/11 kV
- Except for three 11 kV switching stations in Timaru CBD: Grasmere, Hunt and North Streets; and one 110/33/11 kV substation as Bell's Pond.

Distrbution lines and cables

- 11 kV (and some 22 kV)
- Including pole mounted surge arresters, air-break type switches, fuses and links.

Distribution substations

- Including 11/0.4 kV transformers, RMUs, pole mounted reclosers and line regulators, and capacitors.

LV reticulation lines and cables

- Including link and distribution boxes: 400 V.

SCADA, communications, ripple load plants, and RTUs

- Protection and metering.

Tariff meters and load control relays

- At consumer premises (non-network).

Mobile substations and emergency mobile diesel generators

- For use during faults or shutdowns (network – treated as substations for Opex purposes).

Figure 3.4 Assets by category

3.3.4 Sub-transmission and zone substation configuration

Section 3.3.4 provides a summary of our sub-transmission and substation assets. Detailed information can be found in the AMP-Major Assets.

Due to the legacy MED/SCEPB configuration, the sub-transmission asset configuration is different at each GXP, as summarised in Table 3.5

GXP	Sub-transmission and zone substation configuration
ABY	ABY 11/33 kV step-up substation, supplying single circuit 33 kV sub-transmission line to FLE, and from there the 33 kV sub-transmission line to the privately owned OPU Power Station. Two 11 kV feeders.
BPD	110/33/11 kV zone substation with three 11 kV feeders and one 33 kV sub-transmission line to CNR.
STU	11 kV indoor switch room with two incomers from TP GXP, and six feeders supplying the nearby Fonterra Studholme dairy factory, Waimate township, and the surrounding rural area.
TKA	Single 33 kV sub-transmission circuit to 33/11 kV TEK zone substation with four 11 kV feeders, and 33 kV sub-transmission line to GTN, UHT, and other smaller 33/11 kV zone substations.
TMK	Four 33 kV sub-transmission feeders: two double circuit 33 kV lines and two 33 kV cable circuits, to Fonterra's Clandeboye dairy factory (two 33/11 zone substations at Clandeboye). Two 33kV cables (or circuits) to the local 33/11 kV TMK zone substation with six 11 kV feeders. One 33 kV sub-transmission line to GLD. One 33 kV sub-transmission line to RGA. One 33 kV sub-transmission line to RGA tapped off one of the Clandeboye 33 kV lines.
TIM	Two 11 kV circuits to TIM, two 11/33 kV step-up substation, supplying one single 33 kV sub-transmission line to PLP, and two predominantly single circuit and some double 33 kV sub-transmission lines to PAR. Four 11 kV sub-transmission cable circuits to GRM, which then split into a double circuit ring configuration to HNT and NST 11 kV zone substations. Two 11 kV sub-transmission cable circuits to NST (cables rated at 33 kV). Ten 11 kV feeders.
TWZ	Single 33 kV sub-transmission circuit to 33/11 kV TVS substation with four 11 kV feeders.

Table 3.5 Sub-transmission and zone substation configuration

Table 3.6 provides a breakdown of peak load installed capacity and security of supply classification at each of our substations. A summary of the condition of assets can be found in Commerce Commission's Schedule 12A: Asset Condition (a copy of the schedule is available on our website).

Existing zone substation	Current peak load (MVA)	Installed firm capacity (MVA)	Security of supply classification (type)	Transfer capacity (MVA)
ABY	3.8	0.0	N	2.5
BML	0.2	0.0	N	0
BPD	9.9	0.0	N	3.5
CD1	18.8	20.0	N-1	0
CD2	12.3	25.0	N-1	0
CNR	2.9	0.0	N	1.8/0.8/0.6[14]
FLE	2.3	0.0	N	0.5
GLD	6.0	0.0	N	4
GTN	0.2	0.0	N	0
HLB	0.3	0.0	N	0
PAR	9.8	15.0	N-1	4
PLP	4.3	0.0	N	2.5
RGA	10.3	15.0	N-1	4
STU	13.3	11.0	N-1	3.5
TEK	2.7	0.0	N	0
TMK	12.4	25.0	N-1	4
TIM 11/33	12.3	25.0	N-1	0
TVS	2.4	3.0	N-1	0
UHT	1.1	0.0	N	0

Table 3.6 Capacity of major substation assets

[14] *CNR substation has three transfer capacities: winter/summer/BPD off-load.*

3.3.5 Major zone substation assets

Section 3.3.5 describes the age and condition of substation transformers, as well as 33 kV and 11 kV substation switchgear, and ripple injection plants. Detailed information can be found in the AMP–Major Assets.

Zone substations convert sub-transmission voltage to distribution voltage—typically 33 kV to 11 kV in our case.

The age profile of zone substation transformers in Figure 3.5 shows that a third of the transformers were manufactured and installed in the last 10 years, a third between 1978 and 2000, and a third between 1964 and 1976.

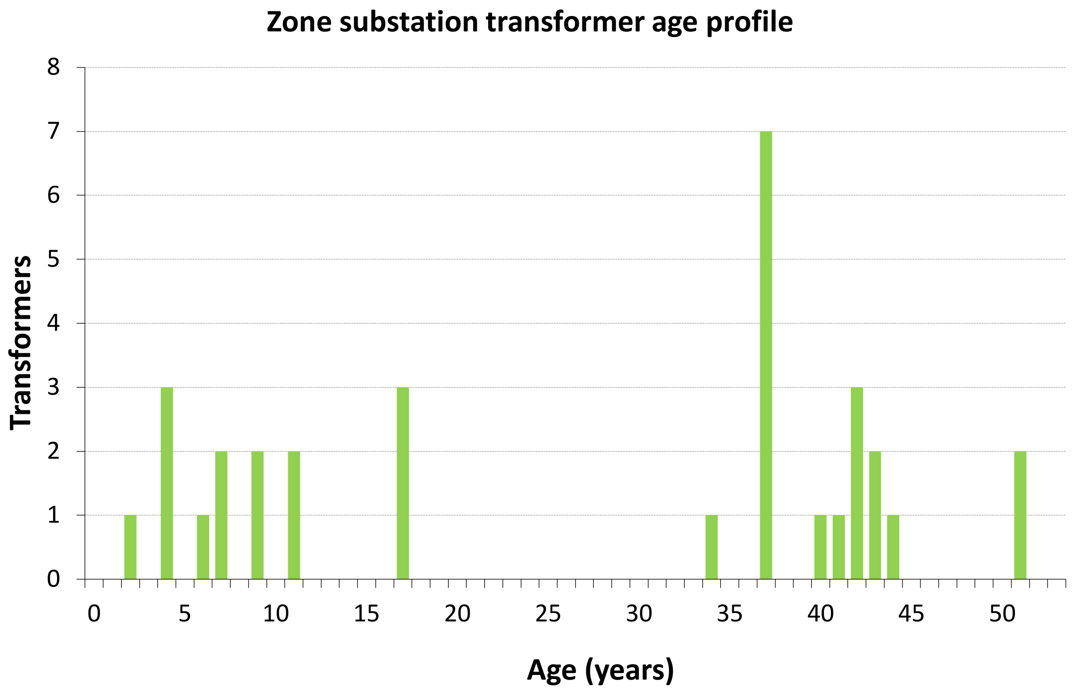


Figure 3.5 Zone substation transformer age profile

The zone substation transformer population is generally in good condition. The older transformers are typically at lower loaded sites and have been refurbished mid-life to ensure reaching expected service life of 50 years. Further refurbishment will be undertaken as the transformers are replaced and subsequently relocated. The oldest transformers i.e. those that have reached 50+ years will be retired when replaced.

The two 5/6.25 MVA transformers released from PAR substation in October 2012 were manufactured in 1973 and 1977. These 38 and 42 year old transformers have been refurbished and reused at FLE and TEK substations to replace the 3 MVA units. Following refurbishment, the transformers have another 20 years of expected service life. The 3 MVA units have been retired.

The 5/6.25/9 MVA transformer released from RGA in September 2012 required its conservator to be enlarged due to an oil expansion contraction issue when fully loaded. This 1982 unit had its conservator enlarged in 2014/15.

Four new 9/15 MVA transformer sets were purchased, installed, and commissioned at PAR and RGA in 2012. In 2014, another 33/11 kV 9/15 MVA power transformers were procured and installed at CNR substation for the new ODL dairy factory near Glenavy.

3.3.5.1 Switchgear

There are three 110 kV SF_6 outdoor CBs on our network. Two are at BPD (one being CB482), purchased in 2008 and operated at 110 kV. The remaining CB (CB522) is also at BPD was purchased in 2013 and is operated at 33 kV.

In 2014, one 110 kV SF_6 outdoor CB (operated at 33 kV) and a switchboard of 11 kV vacuum switchgear was procured and installed at CNR for the ODL dairy factory.

Figure 3.6 shows the age profile of 33 kV switchgear (including 110 kV CBs operated at 33 kV). The age of switchgear ranges between 0 to 40 years, with 39% older than 25 years.

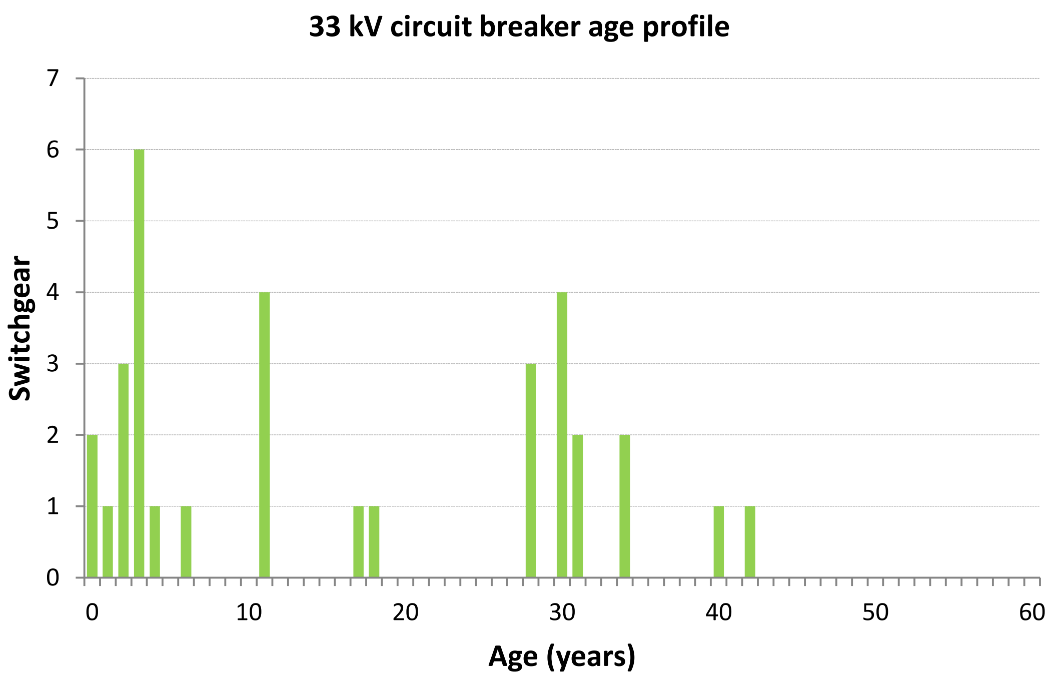


Figure 3.6 33 kV switchgear age profile

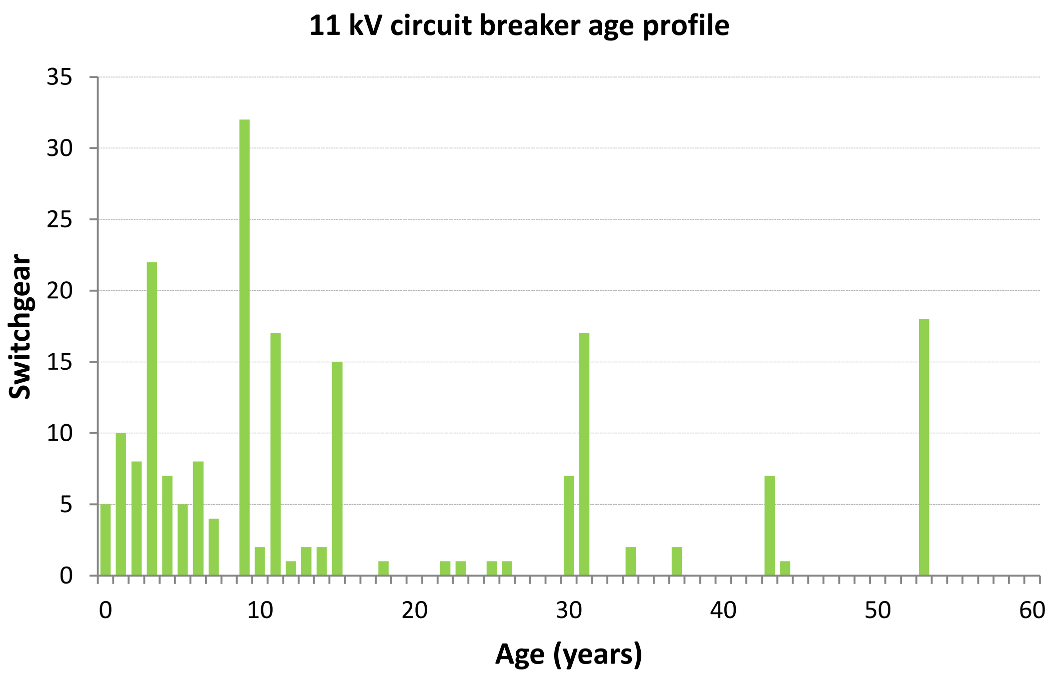
There are 33x 33 kV circuit breakers and reclosers (switchgear) on our network. The majority of switchgear is situated within zone substation compounds to protect zone transformers or sub-transmission lines. Each CB has associated protection relays and/or controller.

Most of the 33 kV CBs and reclosers have vacuum mechanisms. Older units are contained in bulk oil tanks, while more recent units are in SF_6 tanks. The 33 kV bulk oil CBs are due for replacement during the period. Two old RVE bulk oil reclosers were decommissioned and one is available for redeployment, but is only suitable for transformer HV application.

The six new 33 kV vacuum CBs commissioned at PAR substation in 2012 are indoor type with SF_6 insulated chambers.

The two new 33 kV SF_6 puffer type CBs commissioned at RGA substation in 2012 are outdoor type (one old vacuum/oil CB was decommissioned and may be redeployed). The new 33 kV SF_6 puffer type recloser commissioned at Canal Road Corner in 2012, at the tee-off from the Clandeboye 33 kV feeder # 2 (overhead line) for the new RGA sub line, is an outdoor type.

Figure 3.7 gives an indication of the age of 11 kV CBs on the HV network. Older CBs are of the bulk oil variety and were installed between 1962 and 1985. More recently installed vacuum type CBs account for the post-1985 circuit breaker population and are used for new installations and where bulk oil CBs are being replaced.



Indoor 11 kV switchgear age profile

The suites of 11 kV indoor circuit breakers at GRM (1962) were replaced with 20 new VCB boards in 2012 and 2013 using the existing upgraded building.

Inspection of CBs is in line with manufacturer recommendations and significant progress has been made in the last 12 months, with 80% of all CBs now up-to-date. It is expected that the next 12 months will see all CBs fully up-to-date with scheduled routine inspections and maintenance. Following maintenance, circuit breakers are only returned to service if the condition guarantees sufficient remaining life for the next maintenance period.

Battery banks, used to run our protection systems at zone substations, have been replaced with sealed recombinant type batteries that have a higher initial cost, longer expected service life[15], and low maintenance requirements.

Most of the protection assets installed on our network are related to the age of the overhead line, cable, switchgear, or transformer protection. The 33 kV and 11 kV feeder protection systems are generally the same age as the associated switchgear. Protection is

15 The economic life is 10 years, but we usually change battery banks out after 7 years.

tested regularly; if tests determine that the asset is reaching the end of its reliable service life, it is programmed for change-out. The Hunt St substation is part-way through such a protection replacement programme.

The condition of existing zone substation control and alarm varies considerably throughout the system, and is generally dependent on the age of the substation and whether the substation has recently had major switchgear and/or protection systems replaced or upgraded.

The gravelling of switchyards to reduce ground maintenance and enhance personnel safety has been achieved at most sites. Security fencing around sites is regularly checked to maintain site security and prevent unauthorised access. Substation buildings and grounds are regularly inspected and maintained as and when necessary. Detailed information on the life cycle of network assets, including asset condition assessment, replacement, and maintenance can be found in Chapter 6—LIFE CYCLE ASSET MANAGEMENT PLANNING.

3.3.5.2 Ripple plant

The age profile of current ripple injection plants is shown in Figure 3.7

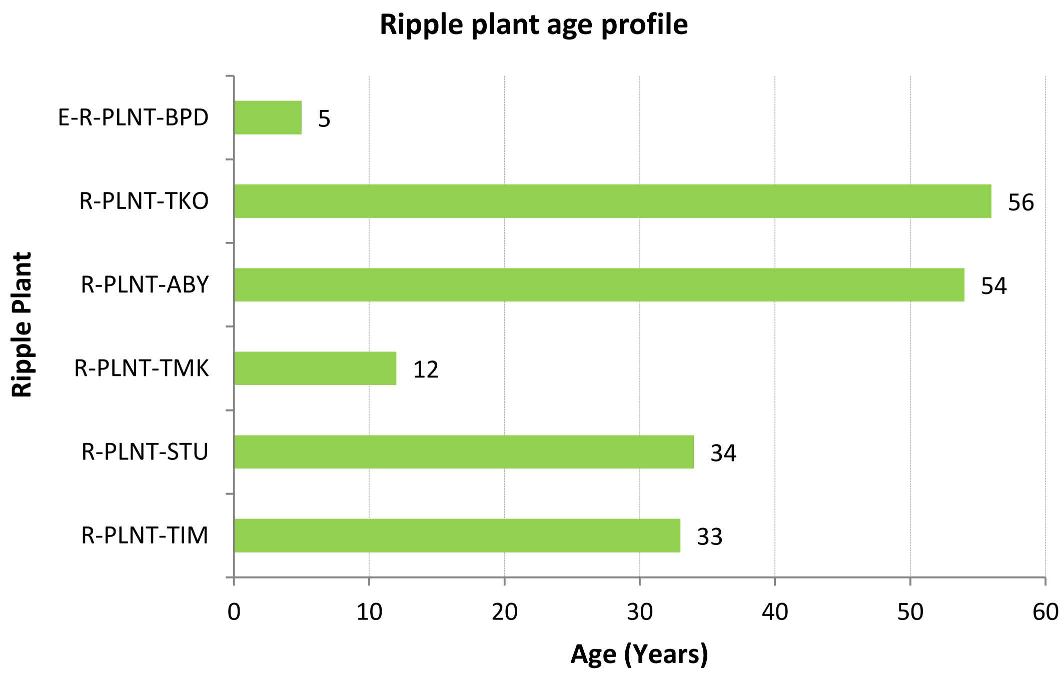


Figure 3.7 Ripple plant age profile

A 10 year program to replace or decommission the old rotating ripple injection plants was commenced in 2000, but deferred in 2008 while a short wave radio load control system was considered. While advanced metering may provide suitable alternative load control in the future, it was decided to continue replacing the old rotary injection plants with modern electronic equipment in order to meet our immediate needs for replacing outdated load control equipment. The replacement of ripple receive relays has been incorporated into the

Smart Meter programme and has been coordinated with the updated replacement programme from 2015/16 onwards, as shown in Table 3.8.

To date, we have standardised our 317 Hz static ripple plants at BPD, TIM, STU, and TMK GXPs. There are two 500 Hz rotary plants in service at TEK and ABY.

A shared ripple plant has been established at TWZ with Network Waitaki Limited (NWL). The plant's frequency is akin to NWL's as NWL holds the larger population of ripple receivers. With the TWZ 33 kV bus run split, and NWL on the other side, we have not been able to use the plant. The plant does not have sufficient power to pass signal through T18 and T19—we are awaiting Transpower's replacement 33 kV switchgear to enable us to receive signal.

Item:	Year:	Programme:
1	2010/11	Reviewed rotating plant condition in ABY and Tekapo areas—completed.
2	2010/11	Reviewed local service security to ABY ripple plant converter—completed.
3	2010/11	The rating of BPD converter was upgraded when the original unit was found to be under-rated for the actual network load—completed.
4	2012/13	Reviewed local service security to TMK ripple plant converter.
5	2012/13	A review of the TIM plant was completed in view of the Transpower plan to upgrade the 11 kV switchboard and 110/11 kV transformers—reviewed again in 2013/14.
6	2013/14	At TMK, two new local service transformers (padmounts) and associated new auto change-over switchboard were commissioned to replace the existing transformers and RMU—completed.
7	2014/15	Procurement, then installation of a new ripple plant cell at STU to suit the lower impedance of the proposed two new Transpower transformers—date revised.
8	2015/16	Build and commission new plant at ABY, subject to Item 1—installation date revised to suit smart meter rollout.
9	2015/16	Decommission rotating plant at ABY, subject to Item 8 which replaces with modern electronic plant—date revised.
10	2016/17	Build and commission new plant at TEK—approximately 800 relays to change.
11	2016/17	Decommission rotating plant at TEK, subject to Item 10 which replaces with modern electronic plant—date revised.

Table 3.7 Ripple plant replacement programme

Any modification to the TEK substation from TKA will need to consider the impact on the ripple plant.

The TMK ripple plant was upgraded with an automatic selection on its local service supply in 2013; and two new padmount transformers were sited outside the ripple building and commissioned from D/O fuses off two local 11 kV feeders. The new transformers supply a new change-over LV local service switchboard inside and the existing transformers and RMU were decommissioned and removed from the building.

The Albury ripple plant's 2016/17 replacement will be preceded by the 2015/16 replacement of the old local service supply—two old 11 kV oil load break switches with a new 100 kVA padmount transformer and a new padmount and kiosk-housed 38 kV rated VCB with protection and control for the ripple plant's coupling cell and local service transformer.

The STU ripple plant has insufficient power output to suit the network due to the growing load. It was suggested by the supplier, after site testing of the asset, to increase the size of the injection cell from 40 kVA to 80 kVA.

Advanced metering deployment is under way and incorporates 317 Hz ripple relays. Priority for advanced meter deployment has been given to the Albury/Fairly and Twizel areas to address our issue with ripple plant.

3.3.6 Sub-transmission and distribution lines and cables

Our network consists of overhead circuits and underground cables operating at voltages of 110 kV, 33 kV, 22 kV, 11 kV, 6.6 kV, and 400 V that distribute electricity from zone substations to rural and urban areas. The majority of rural networks are overhead with a mixture of soft wood, hard wood, and concrete poles. Urban networks are a mix of underground cables and overhead lines.

The proportion of overhead and underground circuit kilometres to total circuit kilometres at each voltage is shown in Table 3.8 below[16].

Circuit voltage:	110 kV	33 kV	22 kV	11 kV	6.6 kV	400 V
Overhead (%)	100%	89%	99%	90%	0%	56%
Underground (%)	0%	11%	1%	10%	100%	44%
Total (circuit km)	**0.1**	**245**	**145**	**3,072**	**7**	**669**

Table 3.8 Proportion of total circuit lengths for overhead and underground circuits

3.3.6.1 Overhead lines

Our overhead network was developed over several decades so it is difficult to identify a single overhead feeder that has reached its predicted 50 year asset life with all of its original components. However, there are well-performing original subsections due to the fact that regular inspection and maintenance can extend the service delivery of overhead systems to the point of distorting the actual age of an asset.

[16] The circuit kilometres are provided irrespective of construction type (i.e. three-phase, single-phase, and SWER).

3.3.6.2 33 kV sub-transmission

The majority of the 33 kV sub-transmission network was installed in the 1960s and 1980s to meet the growing demand from the rural network. The growth spike of 1996 was due to the construction of the 30 MVA dairy factory at Clandeboye. In 2004, a new line was constructed to supply RGA substation. In 2013, a new double circuit 110 kV designed line, energised at 33 kV, was constructed to supply the ODL dairy factory at Glenavy.

The age of 33 kV sub-transmission poles is shown in Figure 3.8.

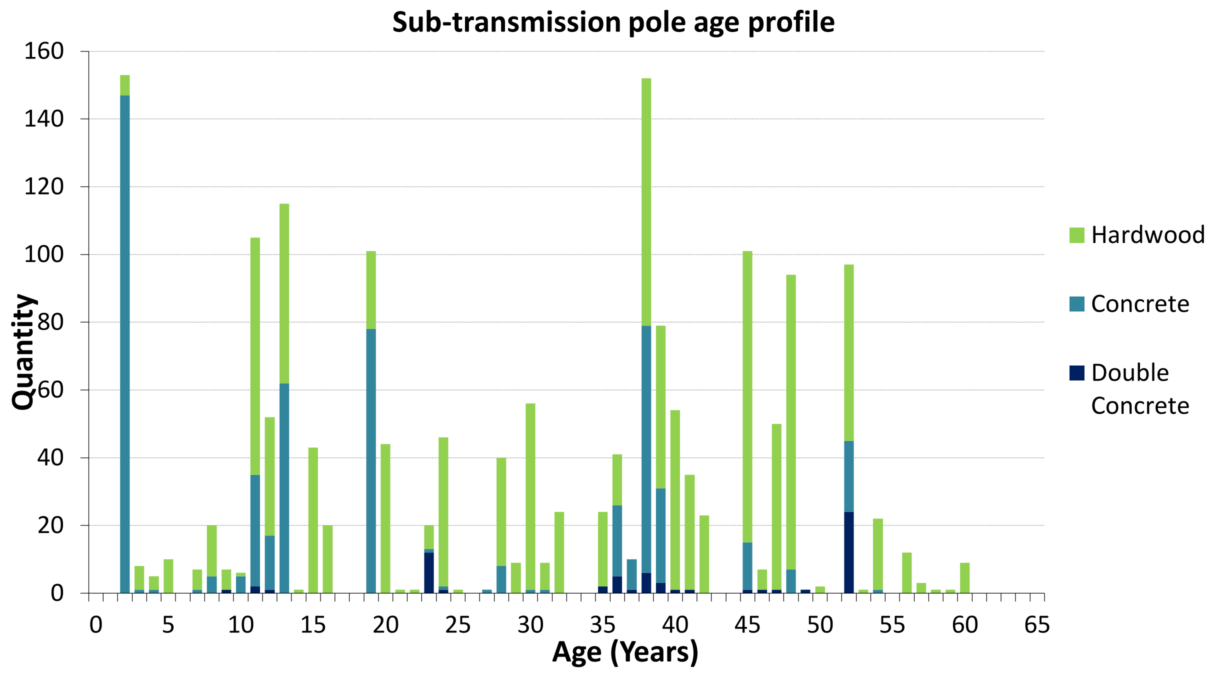


Figure 3.8 Sub-transmission pole age profile

Transmission lines built in the last 10 to 12 years are due for inspection in the 20th year of service. Earlier inspection and maintenance can be triggered by condition. Transmission lines age and routes are shown in Table 3.9.

The two TIM and PAR overhead circuits are currently undergoing refurbishment. The project will span a period of five years and is due for completion in 2015/16. Access to some 33 kV lines is becoming increasingly difficult and expensive as, in most cases, there are constraints on alternative supply.

Location of line	Year of construction	Route length(km)
TIM sub to PAR sub #1	1979 and 1985	18
TIM sub to PAR sub #2	1963	16
TIM sub to PLP sub	1977	16
TMK sub to GLD sub	1966	17
TMK sub to Winchester Township	1979	5
Winchester Township to RGA sub	2003	14

Location of line	Year of construction	Route length(km)
TMK sub to Clandeboye sub	1997	10
ABY to FLE sub	1967	18
OPU Dam to FLE sub	1997	16
TEK sub to Mt Cook sub	between 1975 and 2001	50
TKA to TEK sub	1991	1.5
TWZ to TVS sub	1968	1.5
CNL CB to RGA sub	2010	14
BPD sub to CNR sub	2013	12

Table 3.9 Sub-transmission lines

3.3.6.3 11 kV and 22 kV distribution

The majority of the 11 kV and 22 kV distribution systems were developed in the 1950s and 1970s. There was little development during the 1980s and early 1990s, with load growth accommodated within existing network capacity.

The majority of overhead 11 kV and 22 kV distribution systems developed in the last 15 years are a result of the significant growth in dairying and irrigation. To accommodate the growing demand, we replaced poles and lines with new poles capable of supporting larger conductor, or by reconstructing existing single-phase lines to meet the three-phase requirements of dairy and irrigation load.

Previous AMP profiles of the distribution network were based on the installation date of the asset. As a significant number of older assets have been refurbished to extend expected service life, the effective age of overhead 11 kV and 22 kV distribution assets is more accurately shown in Figure 3.9.

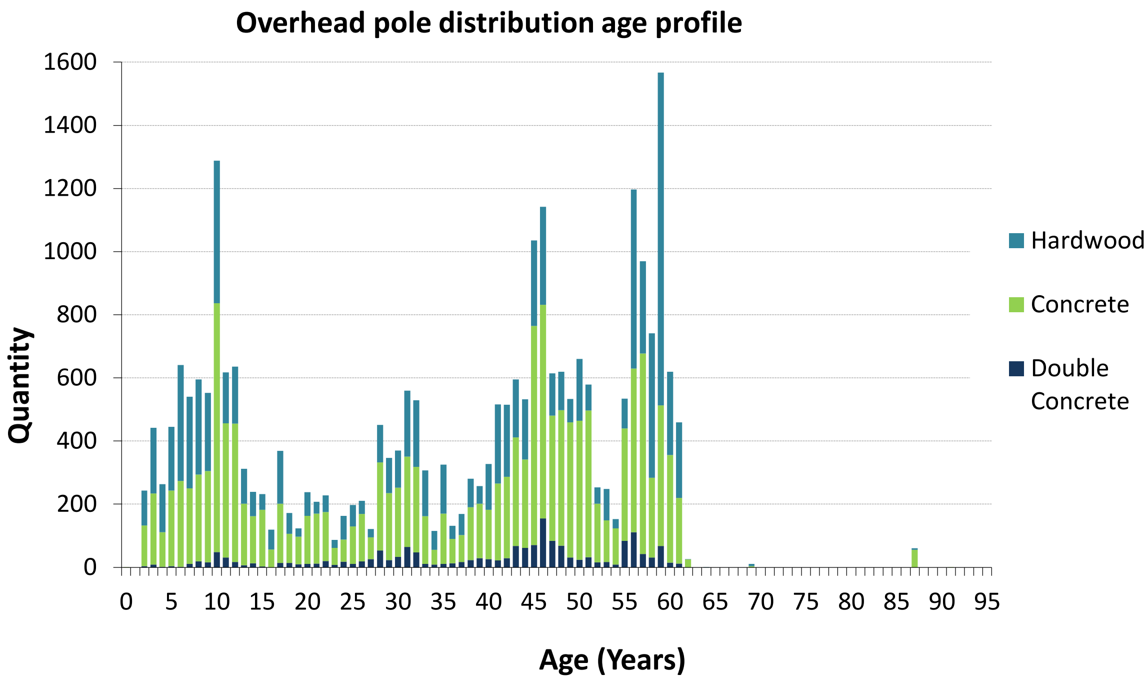


Figure 3.9 Overhead distribution pole age profile

3.3.6.4 LV distribution

All new LV reticulation in urban areas must be underground in accordance with district plans. Rural LV overhead lines are maintained in conjunction with the 11 kV systems.

Existing overhead infrastructure will only be undergrounded if:

- justified by engineering ,or
- health and safety reasons, or
- requested by the district council.

Where existing infrastructure needs to be upgraded, it will be placed underground. Existing overhead lines will be maintained with like-for-like overhead components.

Some capacity constraints may occur should domestic demand exceed the capabilities of the older, smaller conductors used. Under existing district plans conductors cannot be upgraded or replaced overhead and we may need to underground the lines.

Figure 3.10 show the age profile of LV distribution poles. The majority of poles, including softwood, hardwood, and concrete, are more than 35 years old.

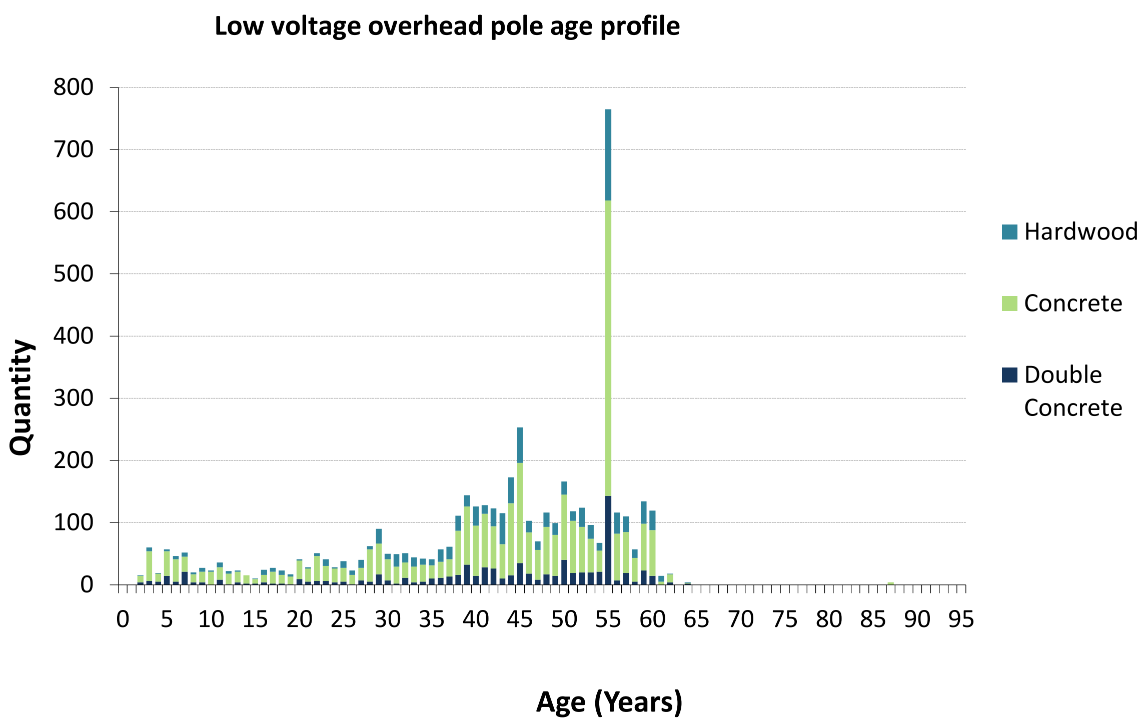


Figure 3.10 LV overhead pole age profile

3.3.6.5 Poles and crossarms

The number of and type of poles are summarised in Table 3.10. The number of poles are sourced from the GIS field capture project conducted in 2007, and subsequent works updates.

All poles have now been individually identified through the filed capture projects and entered into the GIS/AM database (2008/09), with appropriate data relating to age, type, etc. Condition information will be laid over asset information in successive years to build up a complete electronic asset record. In January 2014, a review of softwood poles concluded that softwood poles would no longer be used on the network. Following the review, the estimated life of softwood poles has been reduced as shown in Table 3.10.

A review of our mass reinforced concrete pole making factory in 2013 determined that it was no longer sustainable. The factory was subsequently closed and all concrete poles are now purchased from industry compliant suppliers; pre-stressed concrete poles are specified.

Pole type	Number of poles	Estimated life (years)
Hardwood	12,642	40-60
Softwood	5,332	25-50
Concrete	21,984	60-100

Table 3.10 Numbers and types of poles, and expected service life[17]

[17] Numbers do not include stub or service poles

As many lines were installed in the 1950s and 1960s, the life estimate may need to be increased later in the planning period. Many poles have been replaced to support the growth of the dairy industry in the last 15 years, the adjustment of estimated life will be based on condition assessment.

There are approximately 90% more crossarms than there are poles on the network, allowing for combined HL/LV lines and double arms. As each crossarm has a life of 30 to 40 years, approximately 3% should be replaced annually. Crossarms remain in fair condition so are only replaced when a condition assessment determines the crossarms are no longer capable of supporting serviceability limit state loads.

3.3.6.6 Insulators

Insulators made of porcelain on overhead lines appear to have a life in excess of 60 years and have generally given good service. However, it has become evident that grey NZI porcelain, manufactured between 1980 and 1985, has an issue with the cement used to secure metal or cast components into the insulator or porcelain to porcelain connections. The cement expands over a period of years, causing the porcelain to crack and fail. Glass is now specified for all new disc insulation.

Other suspect porcelain components in devices such as air break switches and blade or fuse connection equipment are identified and replaced.

There has been an issue with recycled 11 kV porcelain insulators failing as a result of being overtightened during refurbishment work. Recycled porcelain is, therefore, no longer used.

The standard 33 kV pin insulator has been replaced with a superior post type insulator for all new and refurbishment work. In long spans and high wind areas, clamp top and armour grip support type insulators are now specified.

Composite type insulation is permitted on the network only if there are not glass or porcelain alternatives.

3.3.6.7 Conductors

Overhead conductors are either copper (Cu), galvanised steel (Fe), steel reinforced aluminium (ACSR), or all aluminium (AAC) and all aluminium alloy (AAAC) types. Early ACSR conductors use an ungreased galvanised steel core and are susceptible to premature corrosion in the comparatively hostile coastal environment. Consequently, we need to closely monitor the condition of this type of conductor, especially around joints and terminations.

There is a number of older copper conductor lines on our network. While copper conductor in general has given good service, smaller copper conductor is inherently more susceptible to tensile failures than ACSR.

The circuit kilometres of all overhead network lines, by three-phase, single-phase, and single wire earth return (SWER), are shown in Table 3.11.

Construction type	33 kV	22 kV	11 kV	6.6 kV	400 V
Three-phase	241.1	28.3	1920	0.0	226.8
Single-phase	0.0	115.9	832.3	0.0	61.9
Single wire earth return	0.0	0.0	0.0	0.0	0.0

Table 3.11 Overhead circuit lengths

Conductor lifespan has been estimate at 60–100 years. However, not all conductors perform uniformly, with some single strand and seven strand copper and smaller smooth bodied aluminium conductors older than 50 years, exhibiting signs of reduced ultimate tensile strength. To date, the performance of seven strand galvanised steel conductors in the Mackenzie area has been acceptable and the conductor is not considered at risk of failure.

Assessment will set replacement priority for smaller inherently weak copper and ACSR conductors, and the older smooth body type conductors that frequently suffer damage during weather events. Special focus is on areas where conductor failure would disrupt the largest number of consumers and/or pose a threat to public safety.

All single strand 11 kV copper conductors in the distribution network has been identified and replaced with ACSR. However, there may remain some isolated 11 kV lines on private land that will be replaced as and when inspected.

Some areas of the network were reticulated using smooth body ACSR conductor strung at 40% of its ultimate tensile strength due to designs incorporating many large spans. Some conductor has been subject to Aeolian vibration. Periodic mechanical overloading conditions, from wind and snow, on many of the smooth body conductors will require assessment of remaining service life.

Some ungreased conductors installed in coastal environments between STU and Glenavy are now showing signs of corrosion. Due to capacity demands, a large amount of the rural overhead network has been rebuilt in recent years, resulting in the replacement of the older, inherently weak and corrosion susceptible conductors. It is important to continue an acceptable rate of conductor replacement to meet the target over the coming years.

In 2008, consultants were commissioned to analyse samples of both copper and ACSR conductors to assess remaining life and recommend strategies for conductor asset management. The conclusion was that predicting conductor end of life using a sample method of assessment was unsustainable. A new industry wide initiative is looking to provide a more informative method of identification. Corrosion of ACSR conductors has also become prevalent under the older type parallel groove (PG) clamps, resulting in a small number of premature joint failures. PG clamps are now routinely replaced with AMPACT connectors during maintenance.

We monitor high strength conductors such as Magpie, Wolf Core, Cub, Snipe, etc. installed on large spans and in snow prone areas. The network's all aluminium conductors (AAC) appear to be in relatively good condition and do not require a high level of scrutiny. All aluminium alloy conductors (AAAC), recently introduced to the network, have performed well to date. Modern design standards are more conservative, resulting in a more resilient network.

3.3.6.8 Pole mounted switchgear

Figure 3.11 shows the age profile of our pole mounted switchgear. A significant proportion of pole mounted switchgear is less than 15 years old, while some date from nearly 60 years ago.

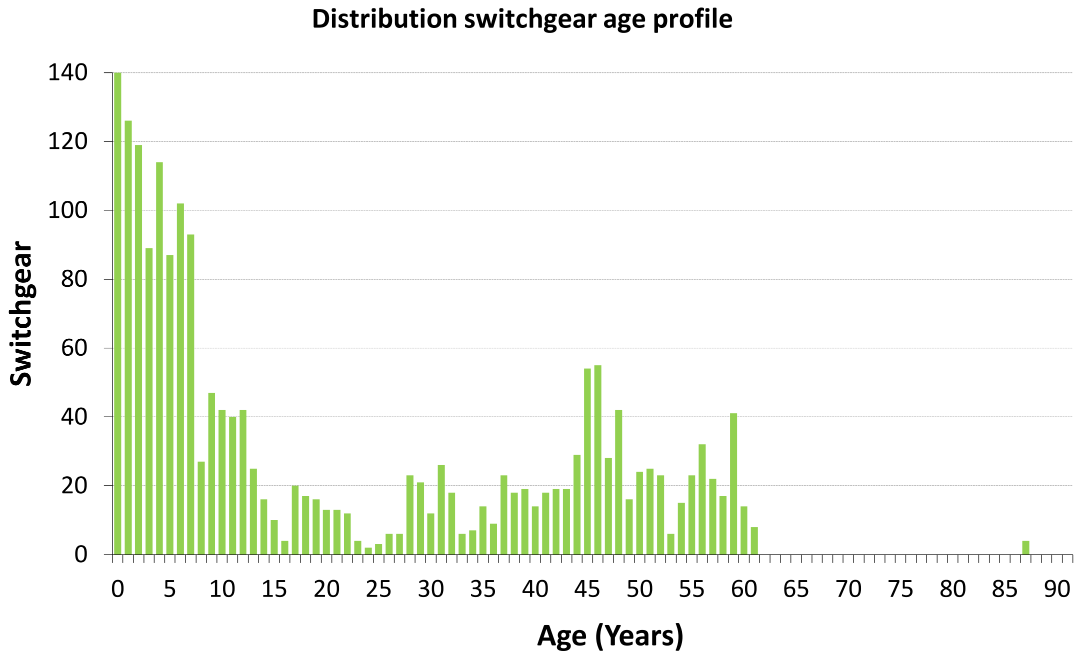


Figure 3.11 Pole mounted switchgear age profile

The distribution network supports a range of switchgear from 11 kV drop out fuses, disconnectors (air break switches or ABS) and 11 kV links through to 11 kV reclosers and sectionalisers.

Older types of 11 kV fuse drop-out units have begun to fail under operation. We are replacing the older drop-out fuses with modern drop-out expulsion fuse units during maintenance, together with the old glass tube type fuses.

The ABS population is managed as part of line maintenance, with some further expenditure to ensure switches are adequately rated for the breaking of line loads, or are uprated with suitable load break equipment.

To avoid ferroresonance for 11 kV cable lengths over 50 m and/or transformers of less than 1 MVA, the cable termination was protected with a disconnector (three-phase disconnect), surge arresters, and a three-phase ganged drop-out unit. With ganged drop-out units becoming difficult to source, we are introducing the use of transformers with internal HV fuses. Switching will still be carried out via the disconnector.

Line fuses are likely to be phased out as larger three-phase motor loads make single-phase operation or fuse isolation of 11 kV lines a less desirable situation.

Only one older style oil weight and chain recloser is still to be upgraded with a modern vacuum electronic equivalent. We are purchasing and installing more reclosers to improve reliability by breaking longer line sections into smaller zones to limit the number of consumers interrupted.

3.3.6.9 Voltage support

Areas north of TMK, including Rangitata, have been part of re-conductoring and re-poling projects, as have the feeder sections from STU substation, to support load growth in Otaio, Waimate, Morven, Waihouranga, and Springbank. Ikawai and Glenavy areas are fed by BPD.

Voltage regulators have been added to maximise the conductors' capacity, providing greater economic benefit than full re-conductoring of the feeder.

Over the past five years, line capacitors have been introduced to support voltage and maintain an adequate quality of supply to the longer overhead 11 kV feeders (required to meet the peak summer demand from irrigation motors). More such sites have been identified and installation will take place over the next year.

3.3.6.10 Pole mounted transformers

Due to seismic constraints, our network standard requires any new transformer 300 kVA or larger to be ground mounted. In future, the existing pole overhead transformer structures in urban areas not meeting our standard, or seismic constraint criteria, will be converted to ground mounted design.

3.3.6.11 Underground cables

Our network contains over 600 km of underground cabling of both the XLPE and PILC varieties. The cables supply power at 400 V, 11 kV and, to a lesser extent, 33 kV.

The type and quantity of cable on our network is shown in Table 3.12.

Construction type	33 kV (km)	22 kV (km)	11 kV (km)	6.6 kV (km)	400 V (km)
Three-phase	28.8	0.0	301.2	0.0	316.8
Single-phase	0.0	1.4	44.3	0.0	7.9
Single wire earth return	0.0	0.0	0.0	7.2	0.0

Table 3.12 Underground circuit lengths

All 33 kV cables on our network are less than 35 years old. The age distribution of underground sub-transmission cable is shown in Figure 3.12

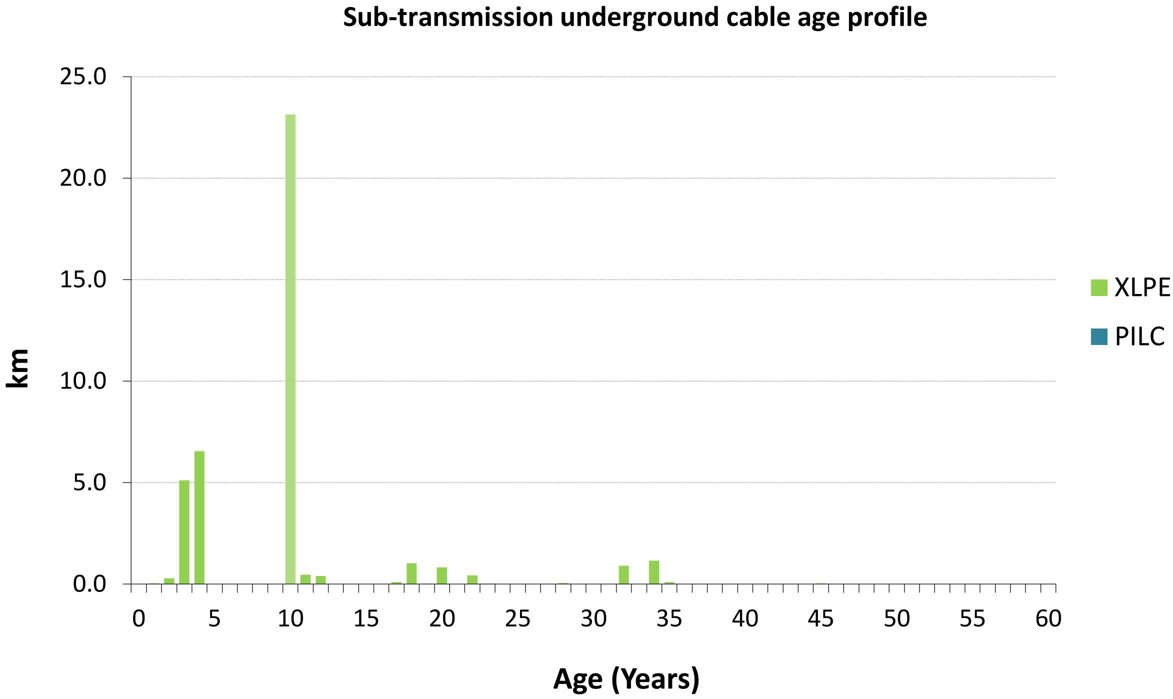


Figure 3.12 Sub-transmission cable age profile

Clandeboye was reinforced with two 33 kV cables in 2004 to meet Fonterra's security of supply requirements. Cabling was chosen as there was no easy route for a double circuit overhead line without significant easement negotiations. As part of our preventive maintenance programme, partial discharge mapping is performed biennially on the Clandeboye cables.

In the past, major transmission cables were offline VLF partial discharge tested every five years to monitor condition. Recent joint failures to the sub-transmission cables have increased the partial discharge to a biennial test as a means to determine change in cable joint condition. Our cable faults tend to be due to joint failure, unfavourable installation conditions, or foreign body or mechanical interference. We have not found a quantitative analysis method to accurately predict the occurrence of faults.

In the absence of reliable data on the longevity of cables of either type under conditions experienced on our network, we have assumed the lifespan of our cables to be the same as that specified by the Commerce Commission in its ODV handbook[18].

The ODV handbook gives us a lifespan of approximately 70 years for PILC cables. We assume a life of roughly 40 years for XLPE cables installed prior to 1986, and a life of 50 years for those installed afterwards. The difference is due to advances in XLPE materials and construction made in 1986 that led to XLPE cables having a significantly longer service life. It

[18] Commerce Commission, *Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Lines Businesses,* 30 August 2004, Table A.1: Distribution ELB Standard Replacement Costs and Lives.

should be noted that out lifespan assumptions are conservative as the areas in which the bulk of our cables are laid are considerably drier than those for which the ODV handbook figures were calculated. We expect very few cable replacements before 2030. However, we continue to monitor the trends in cable condition assessment and use the knowledge gleaned from premature failures to reassess the remaining population's future performance.

We have adopted VLF partial discharge testing as the preferred HV cable test technique to avoid treeing of the XLPE insulation from HVDC test techniques.

The HV and LV distribution networks include distribution boxes, oil switches, and ring main units. Most of the system is relatively new, having been installed in the last 20 to 40 years (the estimated life is 60 to 80 years). Fifty percent of the underground 11 kV distribution network was installed in the last 25 years. The majority of the oldest cables are of PILC construction, which has a 70 year life. The more recently installed cables (20 to 40 year age group) are of PVC and XLPE construction, and have an expected service life of 45 years.

The distribution cable age profile is shown in Figure 3.13.

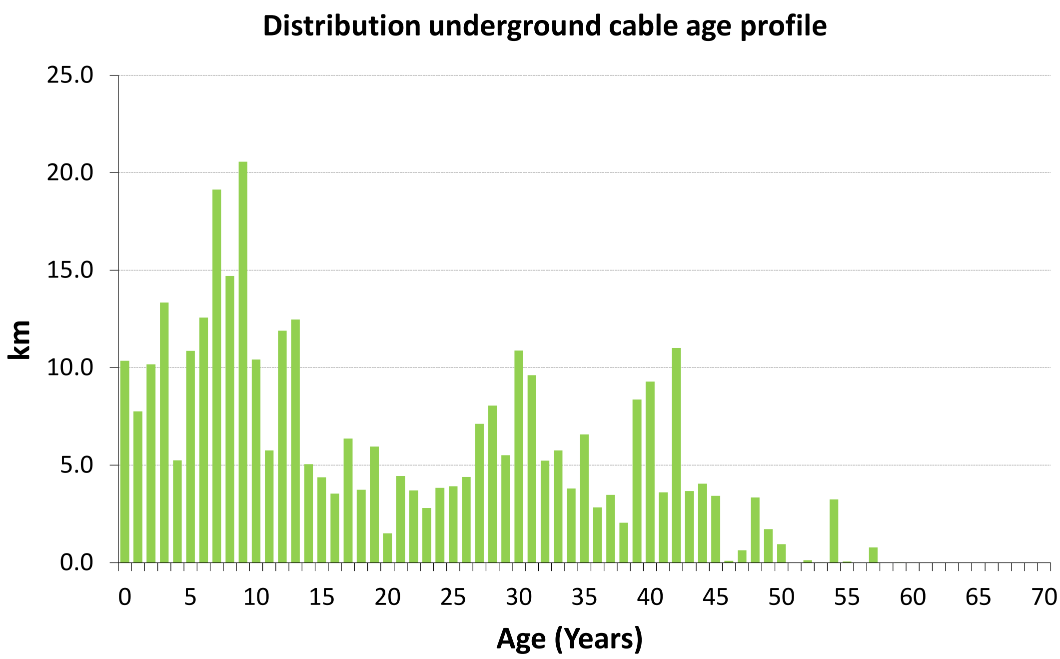


Figure 3.13 Distribution cable age profile

We have implemented a system to log cable faults, building up a history of statistical data to monitor cable performance and record failure modes. There have been, until recently, only one or two 11 kV joint failures per year, which is low relative to the number of joints.

A high incidence of contractor induced cable faults was experienced in 2012 due to the large number of contractors working on the ultra-fast broadband (UFB) project in the Timaru area. 2013 saw a smaller incidence of cable strikes as the contractors were now more experienced at locating and avoiding our cables.

2008 experienced a greater number of 11 kV cable and cable joint failures than expected. Faults were mainly due to contractor damage during work on other services such as water and sewage for the TDC. One or two faults were the result of 1987 vintage plastic 11 kV joints succumbing to partial discharge failure. The faulted joints were sent to a cable joint supplier for testing. However, the testing did not provide much insight into the expected service life of the suspect 1980 decade joints. The emphasis is now on interpreting partial discharge mapping, providing valuable information on the present (at time of test) joint condition and allowing a condition profile to be developed over time for each cable mapped.

The LV conduit system attached to the fronts of buildings in the Timaru CBD is a 'compromise underground system'. Our approach is to maintain the LV conduit system above ground unless the building is to be demolished. The cost to replace the LV conduit system with an underground system is relatively high, at more than $200 per metre.

Maintenance during 2009/10 mainly involved the replacement of LV joints and link boxes—some were replaced in situ while others were moved to pavement level. The majority of underground cables on the LV network are less than 35 years old. Replacement is likely to fall outside the period covered by the AMP. However, during condition assessment of all LV distribution and link boxes in 2009/10, including thermographic inspections, a number of in-pavement Lucy box link and fuse boxes in the Timaru CBD were found to have overheated components.

The investigation and analysis of the findings are yet to be completed and the causes have yet to be reported in detail. If the problem relates to the cable's sweated or soldered connections to the underground LV cables, the maintenance solution may involve cable replacement (i.e. a Capex renewal project). If the heating is shown to only be within the boxes the maintenance solution will cost comparatively less.

A programme was commenced in 2014/15 to systematically replace, over five years, all the central Lucy boxes with above ground distribution/link boxes so as to eliminate the Lucy box issue all allow easier access to the underground and other distribution subs for maintenance and operation.

The LV cable age profile is shown in Figure 3.14.

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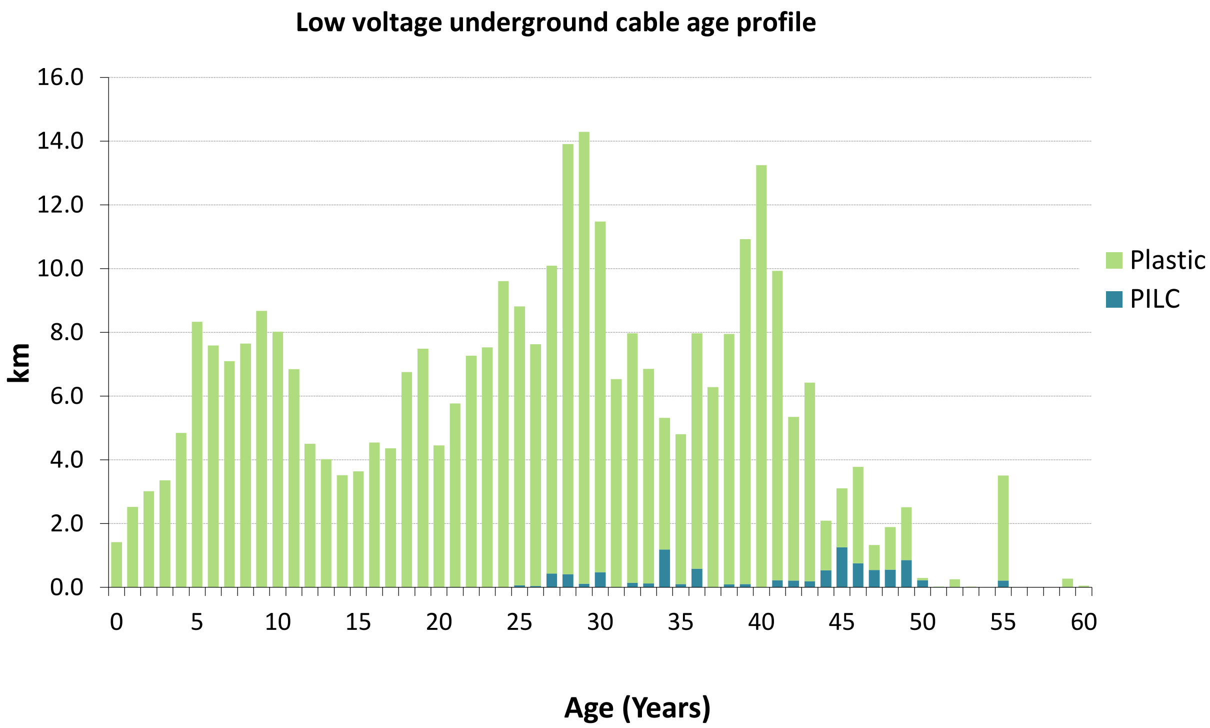

Figure 3.14 LV cable age profile

3.3.7 Distribution substations and transformers

Distribution substations and transformers step down voltage for local distribution. We have 5,492 oil filled distribution transformers in service and the age profile resembles that of the 11 kV overhead lines and cables. The most significant investments in distribution substations and transformers were made in the late 1950s, early 1970s, 2000s, and 2010s.

While the majority of our distribution transformers are less than 30 years old, some date back more than 70 years. The age profile of the transformer population is shown in Figure 3.15.

The expected lifespan of a typical distribution transformer is 50 years. However, there is a large variation in the true life due to ambient conditions and how hard it is operated during its life.

Experience has shown us that lightly loaded distribution transformers in cold conditions can be expected to last 80 years. The finding is applicable to our network as Timaru's average ambient temperature is 12°C compared with the design standard of 20°C.

Irrigation installations use the transformer capacity available for less than half of the year on average. Replacement of transformers is therefore undertaken with consideration to asset condition rather than solely on an age profile basis.

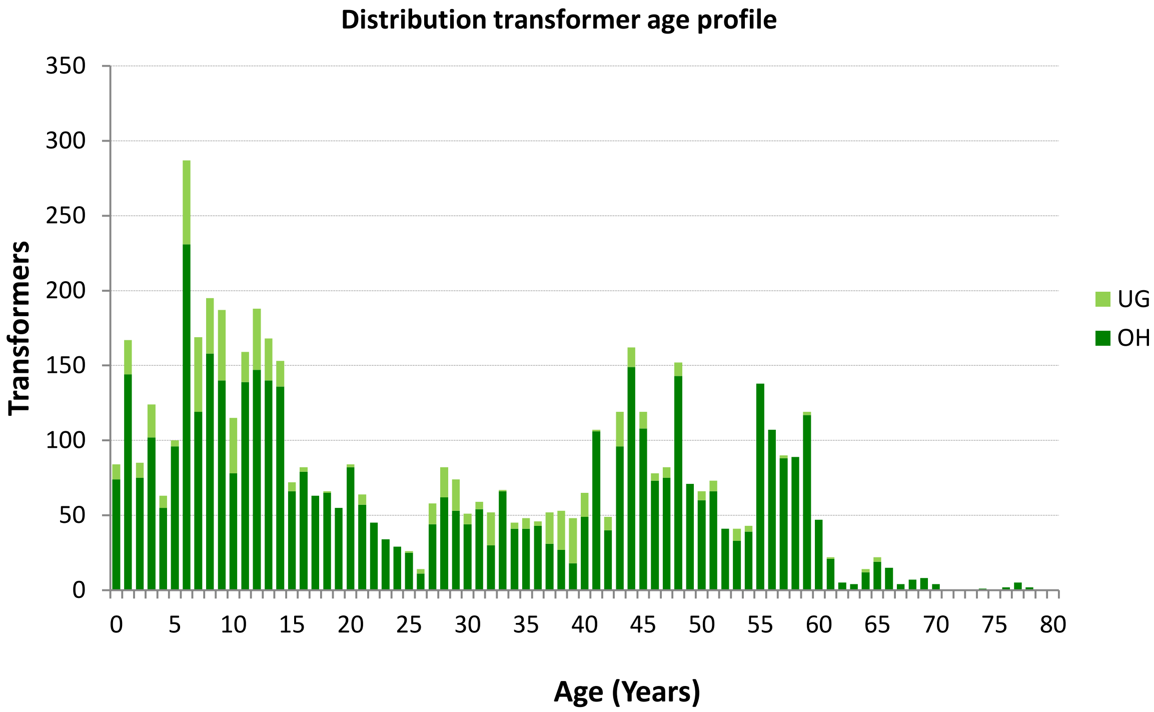

Figure 3.15 Distribution transformer age profile

We have been assessing and maintaining/refurbishing distribution transformers in conjunction with line maintenance. With each line survey, the transformers on that line are visually inspected. When a transformer shows signs of age (e.g. rust), it is replaced and, if appropriate, mechanically end electrically refurbished. If the transformer can be serviced economically, it is returned to service with the next round of line maintenance; otherwise it is scrapped. The frequency of the rolling maintenance programme ensures that individual transformer condition is never poor and will not compromise network reliability.

At present, there are 903 transformers older than 50 years. If no transformers are removed, the number would increase to 908 within the next 10 years. The large increase in the older transformer population warrants specific inspection, rather than standard line maintenance cycles, to assess continuing service or retirement.

Expected remaining life estimates are now required within the transformer database. We are satisfied that all transformers presently on our network have at least 10 years of expected service life remaining due to the current refurbishment programme. With targeted assessment of the oldest population segment, the remaining expected service life of transformers will be determined in the next 10 years.

The in-service quantities of distribution transformers by distribution substation type and kVA rating are given in Table 3.13.

Type	< 20 kVA	< 50 kVA	< 100 kVA	< 200 kVA	< 300 kVA	< 500 kVA	< 750 kVA	< 1000 kVA	>= 1000 kVA	Total
Concrete pad mounted	1	73	25	61	148	92	43	7	8	458
Ground mounted (double end)	0	0	2	7	54	31	15	0	1	110
Ground mounted (single end)	1	2	0	0	1	0	0	0	0	4
Ground mounted (T.E. cubicle)	0	0	0	0	3	31	21	3	2	60
Mounted in U/G sub	0	0	0	0	0	17	13	1	2	33
Mounted indoors	0	0	1	1	4	13	7	4	13	43
Pole mounted	2,634	941	648	401	152	28	1	1	2	4,808
Pole mounted (1.5 pole)	0	0	0	0	1	0	1	0	0	2
Pole mounted (2 pole)	2	1	1	6	15	6	2	0	0	33
Substation (ground mounted)	1	2	3	5	8	2	9	1	4	35
Total	**2,639**	**1,019**	**680**	**481**	**386**	**220**	**112**	**17**	**32**	**5,586**

Table 3.13 Distribution transformer quantities

3.3.7.1 Ground mounted distribution substations

A variety of methods is employed to safely enclose ground mounted transformers. The majority of equipment is commercially manufactured integral with the transformer and provides enclosures for LV and HV connections and fittings. The typical ground mounted transformers on our network are categorised as follows.

- Underground—below ground bunker (Timaru MED area only).
- Cubicle—large streel enclosure type with restricted personnel access.
- Padmount—commercially manufactured kiosk with LV and HV cabinets.
- Building—dedicated or consumer shared concrete block building.

3.3.7.2 Underground substations

The old substation in Timaru currently in service was built in 1960. A newer generation of underground substations in Timaru, dating back to a 1970, replaced the older design, most of which are no longer in service. The newer substations are generally located just below pavement level and are constructed of reinforced concrete wall modules, roof slabs, and cast floor.

The roof slabs are designed to be removed to allow the changing of transformers and switchgear. The removal of roof slabs is rare and would normally be avoided unless absolutely necessary. Underground substations are reliable, with only a few incidents in the design's 40 year life.

Underground substations would normally contain a 400 kVA or 500 kVA transformer (a few contain two of each or one 1000 kVA), one RMU, and an LV switchboard. The substations have continuous fan-forced air ventilation for transformer cooling and operator fresh air. Underground substations also contain a sump pump as some substations can be prone to flooding under heavy, extended rain conditions. All underground substations are checked and maintained, as necessary, after heavy rain. Most underground substations are entered by a pavement manhole and vertical ladder.

There are some 30 underground substations on the inner city network that need to be refurbished before reaching the end of economic life. If an earlier opportunity arises, the underground substations will be rebuilt at ground level. The availability and cost of land for underground substations has been identified as a risk to the replacement process. Individual risk analysis is carried out on a case-by-case basis.

For central city underground substation that require renewal or refurbishment, but where land is not available above ground, a design review was undertaken in 2008–09 to study the feasibility of developing a modern underground substation design with SF_6 or vacuum 11 kV switches with motor operation. The motorised switches would have had to allow remote operation of the 11 kV and, possibly, some LV functions, as well as load monitoring above ground. The remote operation would not only have had to improve safety, but also allow more efficient switching operations by removing the need for confined space procedures before operating the equipment. However, the cost of this option proved prohibitive, even with the project spread over 20 years.

More recently, consideration has been given to the refurbishment of underground substations in three stages over a 20 to 30 year period. The stages would be as follows.

1. LV switch/fuse gear renewal (either within the underground substation or relocated above ground in boundary cabinets).
2. HV RMU renewal to above ground berm location or upgrade to remote controllable RMU within the underground substation.
3. Renewal of the distribution transformer within the underground substation.

Our plan has the advantage of minimising annual refurbishment costs and spreading the total cost over a longer period. It also enables the more frequently operated and inspected equipment to be renewed first, based on individual equipment condition assessment (e.g. LV and RMU units). Renewal may include either relocation above ground or upgrading with a remotely operable unit. Equipment requiring less frequent access and attention (e.g. transformers) would be renewed last in the overall programme.

The condition of our underground substations is generally good, but safety issues around access to enclosed spaces for switch operation will result in refurbishment before the end of economic life. Once the proposed refurbishment design is complete, the project will assess the priorities in the refurbishment of underground substations over the next 20 to 30 years. The priorities will be appraised based on operational and safety considerations, as well as age and condition. All of the work will be done under a planned Capex asset renewal budget.

3.3.7.3 Surface mounted substations

Surface mounted substations on our 11 kV distribution network are of various sizes, designs, and configurations, depending on the era of installation, manufacturer, and site conditions. The types of surface mounted substations include cubicle, padmount, and building.

A surface mounted substation includes a transformer which often has integral LV and HV cabinets attached at each end or on one side (e.g. a padmount substation). The HV cabinet may include an 11 kV switch, such as an RMU (e.g. kiosk or building sub), or an 11 kV termination connecting the transformer to a remote RMU in a neighbouring substation or free standing nearby.

Most surface mounted substations include an LV panel in the LV cabinet, generally consisting of a frame supporting LV bus bars (three phases, neutral and earth bars), isolating links for the transformer connection to the panel, and HRC fuse ways connected to LV reticulation cables. Older kiosk substations have Lucy type porcelain HRC fuse link holders fitted, with the newer kiosk, padmount, and building substations since the 1970s having modern plastic type shrouded HRC fuse link ways fitted.

An exception to the HRC fuse links are certain ex-SCEPB kiosks that, in the 1970s, were fitted with MCCBs rather than HRC fuses. In the event of a problem with the older Lucy HRC fuse link or MCCB LV panels both would be replaced with the modern plastic type shrouded HRC fuse link ways or modern MCCBs respectively. Another exception to the FRC fuse links is the use of Statter LV oil switches in underground substations, some kiosks, and on two pole substations. The renewal solutions for the Statters are: for two pole subs—either HRC fuse switch or ganged fuse holders; for underground surface substations—plastic type HRC shrouded fuse link ways.

The main maintenance issues with surface mounted distribution substations are graffiti, rust, deteriorating paintwork, accumulation of dust, leaves and other environment related material, weed control and we conduct regular checks of the condition of electrical assets and for oil leaks (which are rare) from the transformer and/or HV switchgear.

3.3.8 Line regulators, capacitors, and rural switches

The predominantly rural 11 kV distribution line network includes a number of different types of specialist assets used to control voltage and provide fault protection and operational flexibility, assets include:

- voltage regulators—to correct for varying voltage drop
- capacitors—to correct from voltage drop and provide bulk power factor correction
- reclosers—pole mounted rural circuit breakers
- load break switches—SF_6 gas filled puffer switches to aid sectioning where there are high feeder load currents
- local break disconnectors—standard disconnectors with load break heads fitted, allowing isolations on higher loaded feeders and at tie points
- disconnectors—pole mounted non-load break switches, often called air break switches (ABS)
- fuse links—pole mounted, single-phase break, for protecting spur lines and pole mounted transformers
- ganged fuse links—pole mounted, three-phase break (non-simultaneous), for protecting rural spur lines, with underground cable between the fuses and transformers that are prone to ferro resonance problems
- surge (or lightning) arresters.

3.3.8.1 Voltage regulators

Voltage regulators are automatic devices that monitor the voltage in the line at the point of application and, according to its pre-settings, adjust the output voltage, or downstream voltage, to compensate for changing loads in a time coordinated manner with the supplying GXP or zone substation. We expect the GXP supply transformer to react to grid voltage deviations and regulators to react to the regulation of the distribution line.

11 kV and 22 kV voltage regulators are generally used to maintain an acceptable voltage to consumers' premises as either a short or long term measure. Voltage regulators are used when the higher line impedance of a lighter distribution line would otherwise rest in unacceptable voltage variations, as the total line current varies with fluctuating total instantaneous consumer load.

11 kV voltage regulators are a relatively economical solution for compensating for varying load induced voltage fluctuations compared to the cost of re-conductoring. 11 kV voltage regulators are, however, generally a temporary solution, particularly if the average load on the 11 kV line continues to grow beyond the capacity of the regulator, necessitating a conductor upgrade. At a more extreme level of load growth, a new zone substation may become necessary to shorten the distance from each zone substation to the end of the distribution lines where distribution lines have been upgraded to optimum size.

The size of the regulators currently in use for general line regulation is 200 A. There are a few older units rated less than 200 A, but the newer units meet the 200 A network standard.

One set of 300 A regulators has been installed on a heavy feeder and other such sets may be used as the need arises.

The rapid increase in irrigation and dairy-related rural load in recent years has necessitated installation of a relatively large number of 11 kV line regulators, in some cases with more than one regulator in series on the same line.

The regulators provide a useful buffer period in which the load increase trend on a particular line can be studied and, when sufficient load has been added, conductor upgrades and/or additional feeder or zone substations can be realised.

Regulators displaced by conductor upgrades or new substations may be redeployed elsewhere as growth in irrigation, dairy, and other rural load is currently widespread throughout our area of operation.

3.3.8.2 Capacitors

11 kV capacitors are another means of compensating for voltage drop on an 11 kV line. The compensation cannot be varied as for a regulator as the capacitor installation has a fixed value. Capacitors work by correcting for lagging power factor and are particularly useful where there is significant inductive load such as from irrigation and other motor loads.

As there is always a minimum current flowing in any line, a capacitor may be used to compensate for base voltage drop; it may also be used in combination with one or more regulators. Unfortunately, misapplied capacitors can attenuate ripple signal which can be a hindrance to our load control activities.

3.3.8.3 Reclosers

We use pole mounted reclosers in rural areas for feeder circuit breakers in small rural substations. Reclosers are also used as overhead line circuit breakers for automatic fault clearance and reclosing to clear for example an intermittent fault such as a bird strike, momentary tree branch contact, or slack span clashing.

Reclosers are sometimes used for protection permitting clearance of outlying faults via the operation of fuses. Also, reclosers break a long feeder up into smaller sections, avoiding the tripping of the zone substation circuit breakers (which supply large urban and rural loads) for remote faults. When used for protection in this way reclosers also help avoid both unnecessary momentary supply interruptions and longer outages due to permanent faults affecting the majority of consumers when the fault is beyond the recloser site.

3.3.8.4 Load break enclosed switches

Load break enclosed switches (load break disconnectors) are generally SF_6 or vacuum insulated switches that are rated to break load, but not fault current. Load beak disconnectors are operable via a radio network allowing remote switching of the feeder to perform a load break or load make operation as part of the sectioning and reinstatement procedure. We have only a few of these switches, which are configured for manual operation at this time.

3.3.8.5 Disconnectors

We have a large number of disconnectors (air break switches) of various models and ages installed on the network. Disconnectors are standard items that are required in steady quantities to allow off-load sectioning where there is overhead 11 kV network and three-phase breaking of connected unloaded or very lightly loaded lines.

3.3.8.6 Load break disconnectors

Load break disconnectors (air break switches fitted with interrupters) are effectively disconnectors with additional load break interrupter devices fitted to each phase unit to break load current, particularly at ties between heavy feeders or zone substations. We have dozens of air break switches fitted with interrupters of different makes and types in service.

Some of the older types of switches can be prone to going out of adjustment over time and require a certain amount of maintenance to remain reliable. Since 2008, we have standardised on an interrupter model that is much less prone to going out of adjustment.

3.3.8.7 HV fuse links

We have a large number of HV fuse links installed that are used to protect all pole mounted transformers, for certain cable terminations onto an overhead lines, and for spur lines.

We are replacing the older glass type fuse links with more modern, reliable and versatile drop out type. The standard type fuse link only allows single-phase break, meaning that the HV fuse links need to be installed in series with a disconnector when a three-phase break is required (e.g. a short cable spur to a transformer or in case of a motor that must not be single phased).

3.3.8.8 Surge (or lightning) arresters

Surge (or lighting) arresters are often associated with particular types of assets such as transformers, regulators, HV cables, etc. as well as for general line surge protection. Arresters are designed to passively detect and limit overvoltage surges sue to direct or induced charge from a lightning storm, switching surges, induced power frequency surges, etc.

The arresters contain material that changes conductivity in the presence of an overvoltage. Allowing current to flow to earth, dampening the steep leading edge of the surge wave this generally travels along the line at nearly light speed. The material is designed to recover its high resistance as soon as the surge is dissipated to prevent 50 Hz follow-through current from the normal line voltage, thus preventing a short circuit condition from developing.

In the event that the surge current is too great or a follow-through fault current starts, the earthing lead at the bottom of the arrester blows off in a fuse-like fashion, protecting the arrester from damage and prevents a short circuit which may trip the upstream protection. The arresters in this situation need to be replaced.

3.3.9 LV reticulation lines and cables (including link and distribution boxes)

LV lines and cables distribute electricity from distribution substations to services. LV induced voltage at or below 400 V p-p and 230 V p-n.

LV overhead construction was the traditional method of reticulating urban as well as rural areas in the early days of the New Zealand electricity industry. Now LV overhead distribution lines exist primarily in urban areas. However, for many years now, new LV reticulation has been required by the district council to be placed underground, both in town and country.

The cost of underground vs overhead depends on several factors including cost of labour, materials, topography, and terrain. The economics of placing overhead LV distribution underground presently relies on the district council contributing the cost difference between overhead renewal and undergrounding.

We still have a significant amount of overhead LV reticulation in the town and country areas. Following the damage to underground cables during the Canterbury earthquakes, we decided to cease our undergrounding programme and to instead underground on an application basis.

3.3.9.1 LV underground cables

LV reticulation cables in service include four-core, three-core and neutral screen, and single-core cables. Our current standard for LV reticulation includes for the use of single and three-core Al and Cu cores (with each core XLPE insulated), neutral screen Cu (with PVC sheath), complying to AS/NZS 4026.

Should an object be inadvertently thrust into the cable (e.g. an excavator bucket or a shovel), neutral screen cables provide a neutral conductor outside of the phase conductor, allowing a short circuit to occur and protection to operate, all of which relieves potential harm at the damaged area. Single and four-core cables do not necessarily provide the same advantage, depending on how the strike occurs.

3.3.9.2 Distribution boxes (boundary boxes)

The connection between underground reticulation cables and consumer mains is achieved via distribution boxes. The boxes are usually located on every second boundary in residential and small commercial subdivisions.

We have incorporated a number of different distribution box types into service as styles, materials, and technology have changed over the years. Some examples include concrete, painted electro-galvanised steel, galvanised steel, and plastic boxes.

3.3.9.3 Link boxes

Link boxes contain isolating links that permit the LV reticulation of normal open and closed points (between different circuits and distribution transformers) to be shifted to suit operational and maintenance requirements.

As with distribution boxes, there are several models of link box, of different construction and materials, in service.

3.3.10 Protection relays, SCADA, and communication systems

Protection relays defend the network against electrical faults by detecting over-currents or over-voltages, or other out of limit conditions. Protection relays trip circuit breakers to clear the fault or abnormal conditions from the network. Tripping is necessary to protect such assets as transformers, cables, lines, etc. from hazardous power flow and to remove unsafe conditions that may endanger persons or property. The protection relays are generally automatic, while newer models are monitored by the SCADA system via associated communications systems.

3.3.10.1 SCADA

The SCADA (Supervisory Control and Data Acquisition) system enables remote control of connected substation assets and the acquisition of data. The data describes the present state of the assets including analogues such as currents and voltages; digital points such as position of switches, status of components, etc.; alarms and events such as protection trip events, equipment condition limit alarms, and security alarms. The SCADA system also enables control of certain assets such as circuit breakers. It also records historical data such as events and analogues, for future reference and analysis.

3.3.10.2 Voice radio

Our voice communication system consists of FM, E band, VHF, mobile, portable and fixed site radios operating through hilltop repeaters. The four repeaters used are normally linked via a UHF repeater linking radio control from Washdyke. Each of the linked repeaters can be remotely disconnected from the linkup, again via UHF signalling, to enable local repeater operation.

We also use voice radio arrangement to return alarm signals from some zone substations using tone encoding signals that feed through to the SCADA master. Control and alarms are also sent and received over the radio system to each repeater site for on/off repeater linking.

As represented in the age profile in Figure 3.16, the voice radio repeaters and main radio shelf are due for replacement. The technology is becoming obsolete due to the aging assets requiring more servicing to maintain transmit levels within the correct power regions.

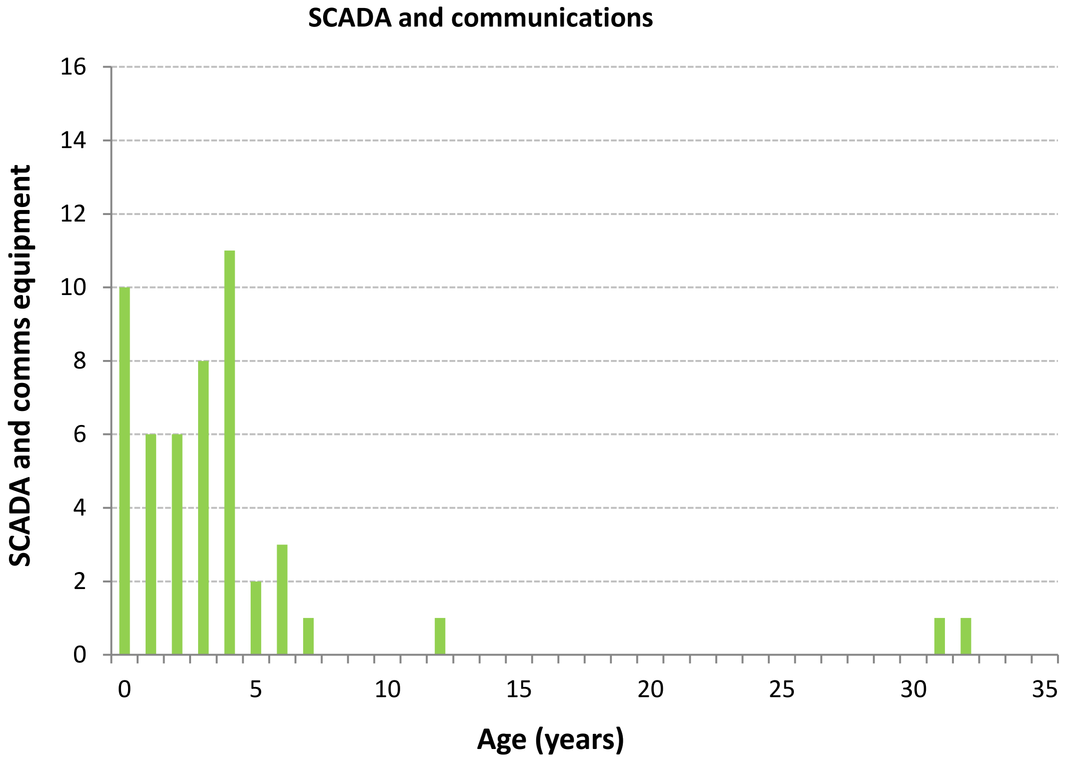

Figure 3.16 SCADA and communications age profile

Replacement of the current system is over a five year period to enable us to retain a level of service coverage while renewing and extending the functionality radio communication system. Cell phones are used to complement and back up radio telephones in many situations. All communications for system operation and control are through voice radio where practical.

3.3.10.3 SCADA communications–radio system

We have a legacy SCADA communications system which is comprised of:

- two UHF FM tone modulated, 1200 baud rate, Conitel protocol paths
- one hired microwave broadband TCP/IP link, DNP3 protocol path
- two landlines as communication paths.

A communications upgrade project, which includes a microwave frequency digital network combined with fibre optic within the Timaru CBD area, was initiated in 2008. The project has multiple stages designed to complement, upgrade, and ultimately replace the legacy system. The new system is discussed further near the end of this section.

The legacy SCADA system communications system pathways are:

- Washdyke—Caveh Hill–STU substations (Conitel)
- Washdyke—Mt Rollesby–TVS and TEK substations (Conitel)
- Washdyke—TIM substation (Conitel on landline)

- Washdyke—GRM/HNT/Victoria substations (RS485 DNP3 landline).

The IPOWER SCADA Master installed in 2006 at Washdyke has been replaced in 2014/15 with a Survalent Master Station. The replacement includes the addition of modules in 2015/16 to upgrade the capability of the Master Station. The load control of module of the IPOWER SCADA Master has been retained in the meantime.

The Master Station allows for DNP3 and SNMP communication to field devices.

Replacing and broadening the extent of communications devices is proceeding as part of the communications upgrade project. The project is still ongoing and, once completed, will resemble a network illustrated in Figure 3.17.

The new communications utilises 5 GHz and other licensed frequencies forming a digital radio network, supplemented in Timaru with a fibre optic network for the three Timaru CBD zone substations (GRM, HNT, and NST), the TIM GXP, and the Washdyke depot control room. It also includes a new fibre optic network between TMK and CD1 and CD2 that links to the 5 GHz digital radio network at TMK.

Only STU, TIM ripple, TVS, and TEK zone substations are still using legacy UHF/Conitel network. These zone substations will be upgraded into the digital radio network in the coming years.

An interim upgrade step for TVS and TEK zone substations may include replacing the aging legacy Conitel RTUs with permanent, new RTUs incorporating DNP3/IP communications. The communications would then be temporarily passed over a leased TCP/IP link from each substation to the Washdyke control room. FLE is now on an IP system over the cell network.

When the digital radio communication is eventually established for TVS, TEK, FTE, and other western substations, the temporary leased communications links would be phased out in favour of the new 5 GHz system.

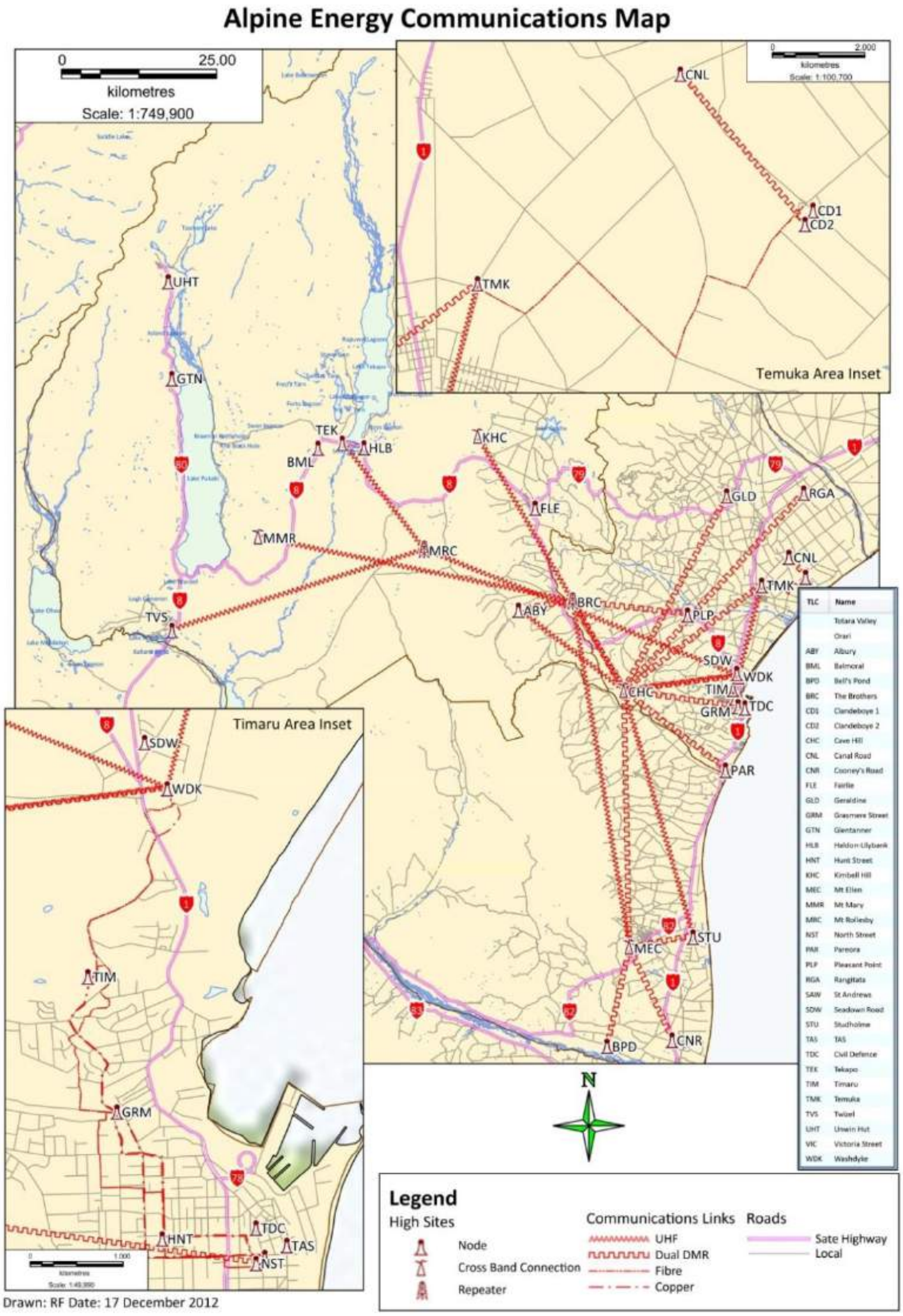

Figure 3.17 Data communication map

3.3.10.4 Load control ripple injection plant

We operate load control of energy storage devices (e.g. hot water cylinders) located at consumers' premises via the operation of ripple injection plants located at ABY, BPD, STU, TIM and TMK. We also use ripple control to shed irrigation load in emergencies and to operate the majority of streetlights. Details of the plants are contained in the AMP—Major Assets.

The aging legacy Conitel RTU that controls the plant at TEK substation is in urgent need of replacement (please see Section 3.3.10.3—SCADA communications–radio system regarding a temporary communications upgrade for TVS and TEK substations).

3.3.10.5 Protection schemes

We have a number of different types of protection relays and associated assets on our network, including:

- electromechanical relays
- electronic relays
- numerical relays
- integration protection and control devices (e.g. recloser controllers).

The protection relays form part of protection schemes and systems that include equipment such as:

- tripping source, generally a battery, a few CT internally powered devices
- instrument transformers (e.g. CTs, NCT, VTs, etc.)
- protection relays
- wiring looms
- cabinets
- trip coils in the circuit breaker/recloser
- fuses
- auxiliary contacts
- terminal blocks.

The protection schemes and settings are designed to clear faults as quickly as practicable to protect life, assets, and property from the effects of the fault. Our network contains a variety of GXP, sub-transmission, and zone substation arrangements with varied fault levels. Each arrangement and fault level combination requires a particular protection application. Consequently, the simpler network arrangements with low fault levels have suitably simple protection schemes (e.g. rural zone substation with small single transformer bank), while the more complex network arrangements with high fault levels have quite complex schemes (e.g. Timaru CBD’s three 11 kV switching substations with closed ring 11 kV sub-transmission interconnects and Transpower GXP supply bus).

As part of our present Capex programme of network upgrades, we are replacing older protection relays and associated legacy assets with modern numeric relays and new associated assets as each substation is refurbished. We have plans to replace all electromechanical and static relays in the substations not scheduled for major upgrades with numeric relays in the 10 year planning periods. Works may include re-looming wiring and replacing the auxiliary as appropriate.

3.3.10.6 Meters and load control relays at consumer premises

We have provided meters and relays at consumers' premises for electricity retailers as part of our current standard use of system agreement. In June 2013, we became a meter equipment provider (MEP) under Part 10 of the Electricity Act. Retailers may choose us as the MEP or seek metering services from another MEP. Our smart meters provide network benefits (e.g. frequency readings) and, accordingly, we have included in our standard use of system agreement provisions that protect our smart meters from interference or damage by a retailer and/or a customer.

3.3.11 Distributed generation

Section 3.3.11 summarises key elements of our policy for distributed generation including connection terms and conditions, safety standards, and technical standards. The policy includes:

- connection and operation standards
- congestion management policy
- emergency response policies
- health and safety standards
- industry rules and standards
- policy on connection below and above 10 kW
- distributed generation plant and commissioning reports, and statement of compliance.

Figure 3.18 shows an example of a photovoltaic array on the roof of a dairy shed.

Figure 3.18 Solar array on dairy shed in Waimate

Table 3.14 summarises the positive and negative effects of distributed generation on our network.

Positive effects of distributed generation	Negative effects of distributed generation
Potential for large uptake to assist in reduction of peak demand at Transpower GXPs. Reducing the effect of existing network constraints. Delaying investment in additional network capacity. Making a very minor contribution to supply security where consumers 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.	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. Altering power flow which requires re-setting and recalibration of protection and controls. Adding very large point injections at lightly loaded points on the network. Providing for LV to MV transformation that facilitates forward and reverse power flow, as in the case of a significant number of PVs exporting into the network on the LV side of a shared distribution transformer. PV installations cannot generate beyond levels prescribed for New Zealand. Possible introduction of harmonics from grid tie inverters. Islanding protection not 100% effective through slowness to operate, or the like, which raises safety concerns.

Table 3.14 Positive and negative effects of distributed generation

3.3.11.1 Connection terms and conditions for distributed generation

We have developed procedures with a simple series of steps that owners of distributed generation can follow to have small scale (<10 kW) and large scale (>10 kW) distributed generation connected to our network.

We adhere to the prescribed charges in Part 6 of the Electricity Industry Participation Code 2010.

Distributed generation that requires a new connection to the network is charged a standard connection fee with adherence with Part 6 of the Electricity Industry Participation Code 2010. We may also recover the costs to reinforce the network from the distributed generator back to the next transformation point.

Installation of suitable metering (as per the technical standard) is at the expense of the distributed generator and its energy retailer.

We recognise the benefits of distributed generation that arise from reducing costs such as those of transmission and deferred investment in the network. However, the distributed generation needs to be of sufficient size and provide peak transmission demand reduction to provide real benefit.

Those wishing to connect distributed generation on our network must satisfy us that a contractual agreement with a suitable party is in place to consume all injected energy—generators will not be permitted to lose energy in the network.

3.3.11.2 Safety standards

A party connecting distributed generation must comply with any and all industry safety requirements and operational advice from us.

We reserve the right to physically disconnect any distributed generation that does not comply with such requirements.

3.3.11.3 Technical standards

Import and export metering must be installed. If the owner of the distributed generation wished to share in any benefits accruing to us, such metering may need to be half hourly.

We may require a distributed generator of greater than 10 kW to demonstrate that operation of the installation will not interfere with operational aspects of the network, particularly protection and control.

All connection assets must be designed and constructed to technical standards not dissimilar to our own prevailing standards.

3.3.11.4 Opuha Dam

A major embedded generator on our network is the 7 MW hydro generator which is an integral component of Opuha Water Limited's irrigation scheme. The Opuha Dam operates on the requirements for environmental, as well as irrigation, flow and has a duty factor of 20%, meaning it is not available regularly for improvement in supply security. Subject to owners' consent, the dam can be used for islanding in order to maintain local supply during Transpower outages for one to two days per year. The generator is unable to black start, hence it is not deemed a secure supply during islanding operations.

3.3.11.5 Photovoltaic (PV) generation on the network

There is growing consumer interest in installing PV with inverters which permits the export of surplus energy to energy retailers back through the network. The rate of connection of such installations has been exponential since 2010, as illustrated in Figure 3.19.

Recent changes in pricing for consumer generated electricity by retailers do not appear to have affected the growth of PV installations. To provide local data on the efficiencies and economics of such systems within our area of operation, we recently installed a PV array and inverter system on the TEK substation building. Interested person can access that data our website.

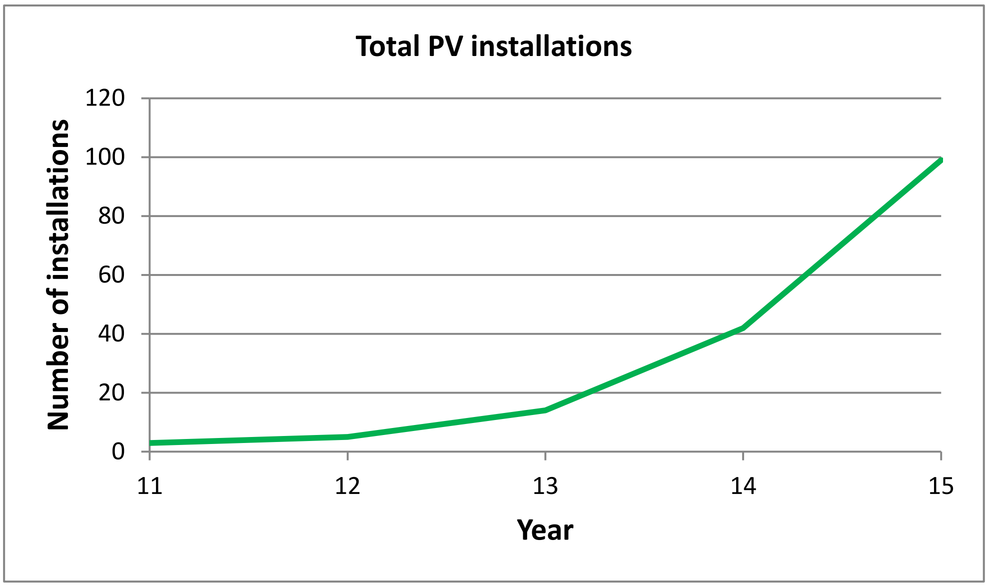

Figure 3.19 Photovoltaic installations as at 31 March 2015

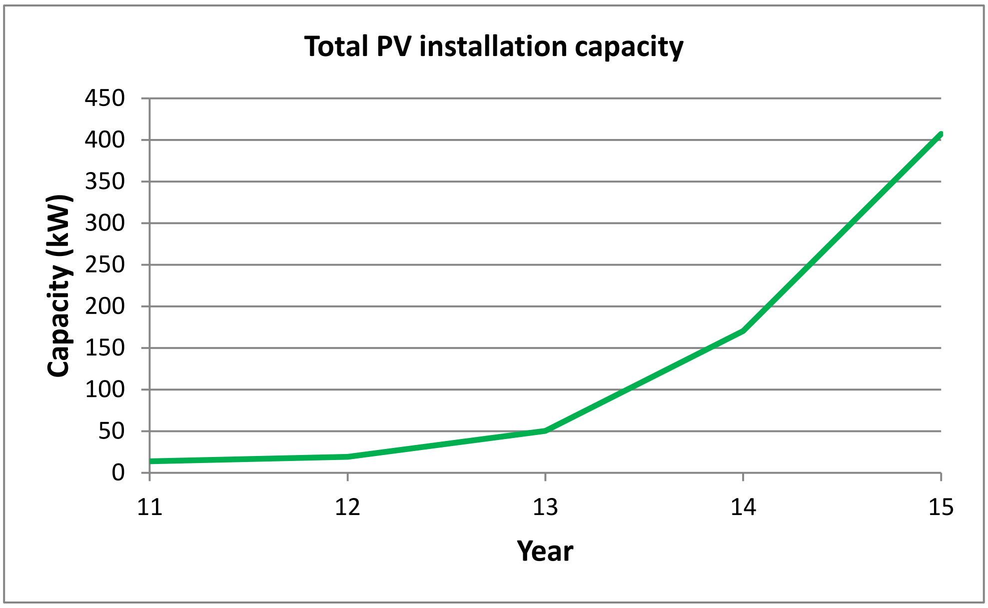

Figure 3.20 Photovoltaic installation capacity as at 31 March 2015

Figure 3.21 and Figure 3.22 show the number of PV installations and total installed capacity by GXP.

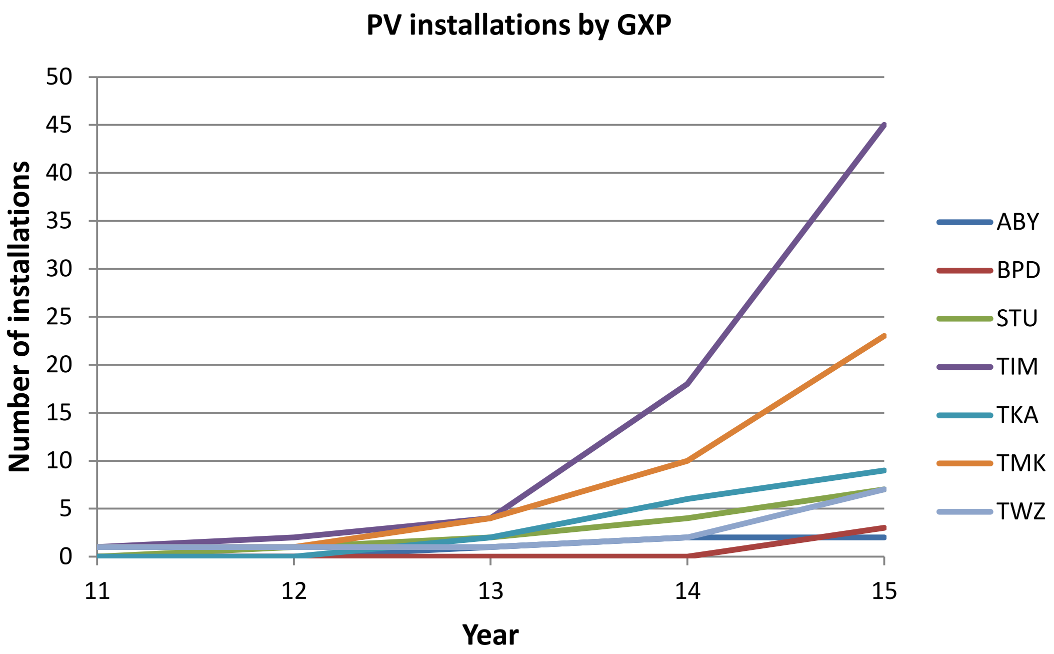

Figure 3.21 Photovoltaic installations by GXP as at 31 March 2015

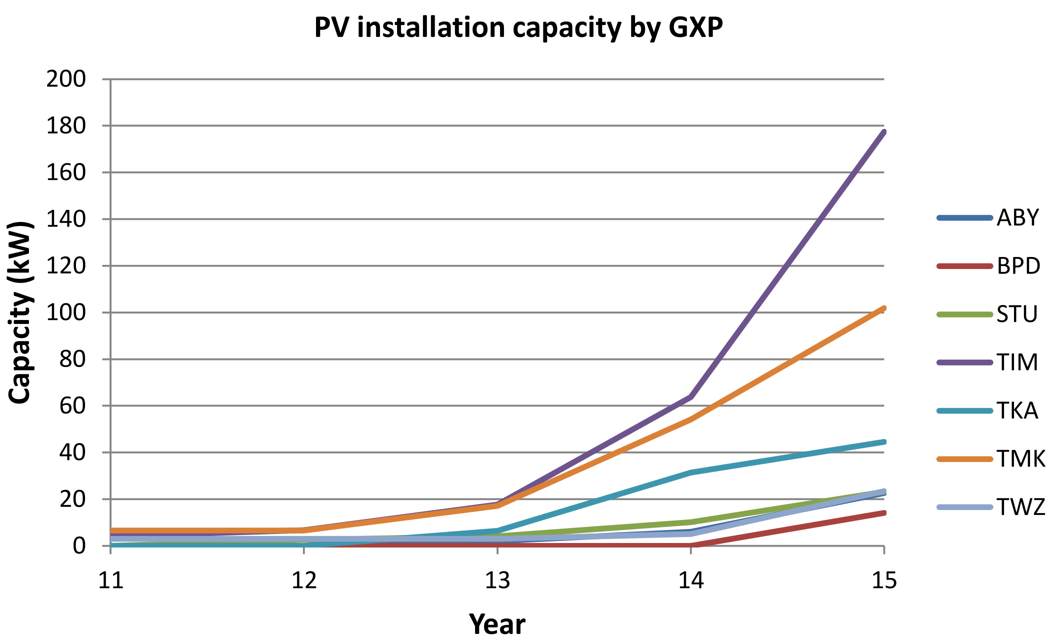

Figure 3.22 Capacity of photovoltaic installations by GXP as at 31 March 2015

3.3.12 Outlook for existing asset configuration

The high demand growth in South Canterbury has effectively consumed the available headroom at a number of lines and substations. The reinstatement of headroom is driving the need for investment to provide additional capacity on the network in a sustainable and efficient manner. The options for network development and configuration are discussed in detail in Chapter 5—NETWORK DEVELOPMENT PLANNING.

3.4 Justifying assets

A key measure of asset justification is the degree of optimisation applied by the Commerce Commission's ODV valuation methodology and, accordingly, we recognise that the ratio of ODRC to DRC provides a good measure of asset justification. The ratio of ODRC to DRC is typically in excess of 99%, meaning that very little optimisation is necessary. However, we also recognise that our network has been built over 88 years by incremental investment decisions. While optimal at the time, those investments may not be optimal if the network was rebuilt in a single instance to supply the needs of today's consumers.

We create stakeholder service levels by carrying out a number of activities on our assets (please see Chapter 4—Performance measures), including the initial step of building assets such as lines and substations. Some assets need to deliver greater service levels than others. For example, our GRM substation supplying the Timaru CBD has a higher capacity and security level (with four sub-transmission feeders and 11 kV switchboards with bus coupler) than our PLP zone substation supplying a residential township and farming areas north-west of Timaru via a single overhead line. Hence the level of investment will generally reflect the magnitude and nature of demand.

Matching the level of investment in assets to the expected service levels required consideration and understanding of:

- how asset ratings and configurations create service levels such as capacity, security, reliability, and voltage stability
- the asymmetric nature of underinvestment and overinvestment, i.e. overinvestment supports higher service levels than expected while underinvestment can lead to service interruption[19]
- the discrete sizes of many classes of components[20]; in some cases, capacity can be staged through the use of modular components
- how past design decisions has resulted in much of our existing network being built up over 80 years by incremental investments that were optimal at the time, but are now considered sub-optimal[21]

[19] Underinvestment typically costs 10x to 100x as much as overinvestment, as was discovered in Auckland in 2006.

[20] For example, a 90 kW pump motor load will require a 200 kVA transformer that is only 50% loaded while running but fully loaded on soft starting the pump motor.

[21] We moved away from incremental investment decisions in the late 1990's early 2000's.

- the need to accommodate future demand growth over the expected service life of the asset
- the need to allow for sufficient line regulation in long rural overhead feeders by using large low resistance conductors which are constrained by voltage rather than current carrying capacity.

In theory, an asset would be justified if the service level created were equal to the service level required. In practice, there are asymmetric risks, discrete component ratings, non-linear behaviour of materials, and uncertain future growth rates. We consider an asset justified if its resulting service level is not significantly greater than the level required, subject to allowing for demand growth and discrete component ratings.

All assets on our network are necessary to meet the load demand and maintain the reliability and security of supply expected by consumers, while meeting regulatory voltage requirements. A small number of assets has been optimised for ODV purposes (most recently in 2004). All of the optimisations have been capacity related (i.e. a 33 kV line operating at 11 kV recorded as an 11 kV line, or a medium conductor optimised to a light conductor). We have not identified any assets as superfluous.

Key new load areas are developing adjacent to river boundaries for irrigation of farmland to increase land productivity. Assets supplying key new load areas are being transformed from single to three-phase, while core assets are being strengthened in capacity and augmented with voltage regulation. From here, feeder load can be diversified with additional lines to provide capacity and improve supply security. Consumer expectations are also an important consideration as supply for dairying load is preferable to irrigation load in the event of fault induced supply disruption. Once a centre of load has been established, further demand is provided by changing supply voltage and installing a new zone substation, typically at 5 MVA capacity.

The AMP does not include non-system related land and buildings, or non-network assets such as motor vehicles, office equipment and furniture, etc. We own meters and charge retailers trading on our network for metering services where we are the metering equipment provider. Metering assets are not covered in this AMP.

For further information on our network assets, please see the AMP—Major Assets.

4. PERFORMANCE MEASURES

4.1 Introduction

Chapter 4 details our performance targets, explains how we set and performed against those targets, and, where appropriate, provides forecasted future performance.

4.2 Why measure performance

We measure performance in order to support the process of continuous improvement. The regulators also set a number of performance targets in accordance with the various acts and regulations under which we operate. Our performance measures can be broken down into four high level categories:

- safety
- service standards
- service levels
- financial.

Each measure of performance, how we set it, our performance against it and, where appropriate, targets for future performance are discussed in the following sections.

4.3 Safety

Safety is our first and foremost value. We maintain our safety policies to keep the public and our people safe. We conduct an extensive education programme to make the public aware of the dangers of electricity. More information on our policies and public awareness campaign can be found in Chapter 7—RISK MANAGEMENT

Our performance measures are based on critical aspects and specific goals established annually through our Safety Plan. Our safety performance is measured by both internal and external audits of our safety management systems for compliance with the following legislation:

- Health and Safety in Employment Act 1992 and subsequent amendments
- Electricity Act 1992 and subsequent amendments
- Electricity Safety Regulations 2010
- Electricity (Hazards from Trees) Regulations 2003
- NZECP34:2001: Maintaining safe clearances from live conductors
- NZECP35:1993: Power system earthing.

4.3.1 Internal audits

We carry internal audits out regularly by requiring that:

- the CEO, General Manager—Safety and Risk, and the Health and Safety Committee conduct an annual audit of the Health and Safety Management Plan
- an annual self-assessment is carried out by applying the ACC Workplace Safety Management Practices criteria; managers and the chairperson of the Health and Safety Committee confirm staff training records annually
- managers conduct regular tours and audits covering the contents of the Health and Safety Management Plan
- managers audit contractors as work progresses on tendered projects.

4.3.2 External audits

External audits are carried out at least every five years by the Electricity Authority and JAS–ANZ accredited audit bodies. The audit determines compliance against standard AS/NZS901:2008 Electricity and Gas Industries—Safety Management Systems for Public Safety. Following a successful audit, an audit certificate is issued. Our current audit certificate was issued on 27 September 2015 and remains current till 27 September 2018.

4.4 Service standards

4.4.1 Measuring the impact of interruptions

Our consumer surveys have shown that our consumers consider the reliability of supply to have the greatest impact on them. We measure reliability of supply through the internationally accepted measures of SAIDI, SAIFI, and CAIDI.

4.4.1.1 System average interruption duration index

SAIDI measures the total system minutes that supply was interrupted during the year. SAIDI is derived using the formula—

$$\frac{\sum(Interrupted\ consumers\ \times interruption\ duration)}{Total\ number\ of\ connected\ consumers}$$

SAIDI provides the consumer with an indication of how long the electricity supply was interrupted during the year. The measure can be reported as a whole of network or it can be applied at a much lower level (e.g. feeder).

4.4.1.2 System average interruption frequency index

SAIFI measures the number of interruptions that occurred during the year and is derived using the formula—

$$\frac{\sum(Number\ of\ interrupted\ consumers)}{Total\ number\ of\ connected\ consumers}$$

SAIFI provides the consumer with an indication of how many times the electricity supply was interrupted during the year. The measure can be reported as a whole of network or it can be applied at a much lower level (e.g. feeder).

Considering the measures of SAIDI and SAIFI side-by-side gives consumers an indication of whether interruptions on the network are short but frequent, or long but rare.

4.4.1.3 Consumer average interruption duration index

CAIDI measures the average system minutes that consumers were without supply during the year. CAIDI is derived using the formula—

$$\frac{\sum(\mathit{Number\ of\ interrupted\ consumers} \times \mathit{interruption\ duration})}{\sum(\mathit{Number\ of\ interrupted\ consumers})}$$

CAIDI provides the consumer with the average time that they were without electricity supply during the year. The measure is derived by dividing the total SAIDI by SAIFI. CAIDI can also be reported as a whole of network or be applied at a lower level (e.g. feeder).

4.4.2 Setting the reliability targets

The Commerce Commission sets annual targets for performance against SAIDI and SAIFI. The targets between 1 April 2010 and 31 March 2015 were set using the five year average normalised performance for the period 1 April 2004 and 31 March 2009[22]. The targets set from 1 April 2015 are set using the 10 year average normalised performance for the period 1 April 2009 to 31 March 2014[23].

The Commerce Commission does not set a target for CAIDI as the measure is an average and is derived by dividing SAIDI performance by SAIFI performance.

Performance measures are intended to indicate if current performance has worsened compared to historical performance. The Commerce Commission compares performance against targets to judge whether there has been a sustained material deterioration in the network over the reported period.

Reliability is relatively easy to physically build into a distribution network—the problem is doing so economically. The impact of expenditure on reliability is non-linear; that is, a small improvement in reliability comes at a high cost. The Commerce Commission sets its targets on the assumption that consumers do not want to pay a significantly higher cost for a small increase in reliability. Our consumer surveys have historically supported our assumption.

[22] Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2010, Decision No. 685, 30 November 2009.

[23] Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2015, [2014] NZCC 33, 28 November 2014, Schedule 4B: Adjustments to Quality Measures, clause 7.

4.4.3 Performance against the targets

Table 4.1 shows our normalised performance against target between 1 April 2005 and 31 March 2015, as well as forecast performance for the current year[24] and the year ending 31 March 2017[25].

Year	SAIDI (reported in system minutes)		SAIFI (number of interruptions)		CAIDI (reported in system minutes)
	Performance	Variance[26]	Performance	Variance[27]	Performance
2005/06	58.60	-29.60	1.08	-0.02	54.26
2006/07	1,113.93	+1,025.73	1.87	+0.77	595.68
2007/08	149.50	+61.30	1.69	+0.59	88.46
2008/09	200.94	+112.74	1.69	+0.59	118.90
2009/10	332.36	+244.16	2.18	+1.08	152.46
2010/11	225.89	+61.70	1.71	+0.02	132.11
2011/12	161.60	-2.62	1.26	-0.43	128.14
2012/13	148.27	-15.95	1.30	-0.39	117.54
2013/14	281.12	+116.9	2.03	-0.34	138.48
2014/15	140.28	-23.94	1.16	-0.53	97.17
2015/16[28]	150.68	-3.48	1.13	-0.38	102.29
2016/17	132.81	-21.34	1.30	-0.21	102.16

Table 4.1 Performance summary—SAIDI, SAIFI, and CAIDI over 10 years

4.4.3.1 Normalisation of reliability performance

In setting of the performance measures, the Commerce Commission recognises that the reliability data is susceptible to variation resulting from events that are largely outside of the electricity businesses' control, such as force majeure events (e.g. earthquakes) and other

[24] Current year performance (1 April 2015 to 31 March 2016) is not finalised at the time that the AMP is published (i.e. 31 March 2015).
[25] Forecast performance for both SAIDI and SAIFI for 2016/17 is based on Commerce Commission targets.
[26] The SAIDI target from 1 April 2010 was 164.22 minutes, and from 1 April 2015 is 154.155 system minutes per annum.
[27] The SAIFI target from 1 April 2010 was 1.69, and from 1 April 2015 is 1.507 interruptions per annum.
[28] SAIDI and SAIFI figures are as forecast at the end of January 2016 and presented to the Board of Directors at the February 2016 Board meeting.

major events (e.g. snow storms). To account for variability, the Commerce Commission uses the IEEE 2.5 Beta[29] method to normalise our annual performance.

We have had our performance normalised at 4 of the last 10 annual review dates.

In 2006, we had a major snow storm which contributed to over 900 system minutes to our total un-normalised SAIDI of 1,114 system minutes. The normalised performance was 208 exceeding the target SAIDI level by 120 minutes.

In 2010 we again experienced severe weather events, which saw our performance of 332 system minutes normalise to 146, exceeding the target SAIDI level by 57 minutes.

In 2013, heavy rain and snow storms in June, followed by high winds in July and September saw lines brought down, predominantly by trees that are outside of the fall zone falling on the lines. Severe weather events contributed over 660 system minutes to our reported un-normalised SAIDI of 885 minutes. Our normalised performance was 275 SAIDI minutes, exceeding the target level by 110 SAIDI minutes.

In 2015, we had a major snow storm in June, a wind storm in July, and a crossarm fire in April. These events added a total of 264 system minutes to our un-normalised SAIDI. Although we have already exceeded our SAIDI target for the year, we expect to come under our SAIDI limit set by the Commerce Commission.

4.4.3.2 Quality incentive scheme

Under the quality incentive scheme, 1% of our maximum allowable revenue is at risk based on our performance for the financial year. The Commerce Commission sets three levels of performance: collar, target, and cap (the cap being our limit). If our SADI and SAIFI performance comes in under the target, we gain up to 1% in revenue. If we come in between the target and the cap, we lose up to 1% of revenue. Exceeding the cap would result in a breach, potentially triggering an investigation.

4.4.3.3 Planned and unplanned interruptions

To get a fuller understanding of our performance, we measure planned and unplanned interruptions separately. Planned interruptions are those where consumers are given at least 48 hours’ notice of power going out. Unplanned interruptions are those where consumers are given less than 48 hours’ or no notice at all.

Measuring planned and unplanned interruptions gives us an indication of the inconvenience caused to consumers on our network. We assume that the inconvenience of a planned interruption is less than that of an unplanned one, as consumers are better able to plan for the outage. Commerce Commission’s 2015 Determination instructs to normalise performance by halving the actual SAIDI and SAIFI figures for planned interruptions. Halfling the SAID and SAIFI associated with planned outages is designed to encourage planned

[29] The IEEE 2.5 Beta is based on an EDB’s reliability data exhibiting a log- normal distribution from which a boundary value is derived as being 2.5 standard deviations from the mean. Currently, where the cumulative effect of an outage over a 24 hour period exceeds the boundary value, the total SAIDI minutes of this period are replaced by the boundary value.

outages to do network maintenance, thereby reducing the risk of unplanned interruptions. We try to avoid planned outages during maintenance by using a combination of live line glove an barrier techniques, and level one live line sticking work (live line clamps).

Table 4.2 provides our actual performance against target for planned and unplanned interruptions for the year ending 31 March 2015.

Measure	Target 2014/15	Actual 2014/15
SAIDI Class B—planned	49.30	48.60
SAIDI Class C—unplanned	115.00	91.30
SAIFI Class B—planned	0.30	0.28
SAIFI Class C—unplanned	1.39	0.87

Table 4.2 Performance summary—planned and unplanned outages

4.4.3.4 Vegetation management

Vegetation management has been and remains a concern for us due to the number of outages and SAIDI minutes attributable to debris flown into our lines.

We are of the view that the Electricity (Hazard from Trees) Regulations 2003 is inadequate with respect to the defined 'growth limit zone, as the limit only considers distance from trees in calm weather conditions. The limit set under the regulations of 1.6 m of an 11 kV line is of no significance during moderate to high winds or storm conditions. During high wind conditions, branches are broken off trees and blown hundreds of metres by the wind creating a hazard. To counter this hazard, we are approaching owners and offering to cut trees that are within the fall zone.

4.4.4 Causes of unplanned interruptions

The breakdown of unplanned interruptions by cause is shown in Table 4.3 and Figure 4.1.

Number of unplanned outages by cause (in SAIDI minutes) during 2014/15			
Cause of fault	**No. of outages**	**Consumers affected**	**SAIDI minutes lost**
Adverse environment	1	1,915	1:43
Adverse weather	37	4,218	17:09
Defective equipment	58	9,716	35.32
Human error	0	0	0.0
Lightning	5	2,291	8.00
Third party interference	25	2,659	11.28
Unknown	18	3,900	9.19
Vegetation	15	1,141	5.13
Wildlife	12	1,645	2.54
Total	**171**	**27,485**	**91.18**

Table 4.3 Unplanned outages by cause

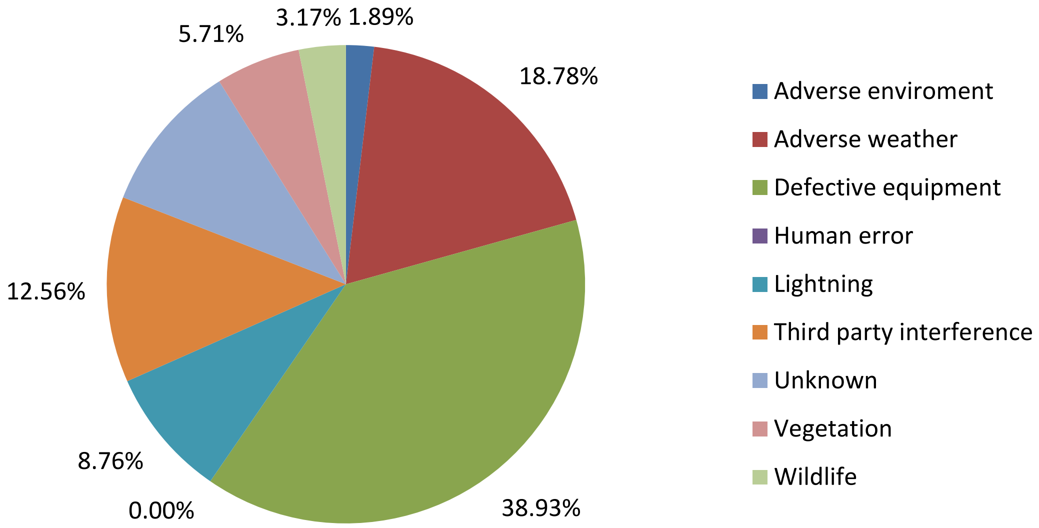

Figure 4.1 Percentage of unplanned outages by total SAIDI minutes

4.4.5 10-year reliability targets

Table 4.5 provides our 10 year reliability target levels for SAIDI and SAIFI. Information on five year forecasts for Class B and C interruption SAIDI and SAIFI can be found in Schedule 12d: Report Forecast Interruptions and Duration published on our website.

Measure	Year ending 31 March									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SAIDI	154.16	154.16	154.16	154.16	154.16	151.07	151.07	151.07	151.07	151.07
SAIFI	1.51	1.51	1.51	1.51	1.51	1.48	1.48	1.48	1.48	1.48

Table 4.4 Primary consumer service levels

The automation of pole mounted reclosers and other network improvements are expected to increase the efficiency of switching for planned outages and reduce the response time associated with switching for faults. Improvements can lead to gains in SAIDI and allow us more planned outages for upcoming Capex projects.

Similarly for SAIFI, the revised targets will allow savings from reduced frequency of fault related outages.

4.4.6 Worst performing feeders

Looking at the worst performing feeders can help us identify and target necessary expenditure on the network. However, the performance of worst performing feeders should not be used as absolute measure as distribution network are dynamic, and a change in network configuration will impact on the performance of individual feeders.

The ten worst performing feeders as at 31 March 2015 are listed in Table 4.6 and Table 4.7.

Feeder	No. of events	SAIDI (in system minutes)	SAIFI (no. of interruptions)
Fairlie Rural	12	6.28	0.06
Woodbury	12	4.59	0.03
Seadown	12	3.44	0.06
Morven	9	3.32	0.03
Speechley	9	2.37	0.02
Cave	8	0.32	0.01
St Andrews	8	0.21	0.00
Holme Station	7	4.05	0.03
Levels	7	1.35	0.01
Waihaorunga	6	7.43	0.04

Table 4.5 Ten worst performing feeders by number of outages in 2014/15

Feeder	No. of outages	SAIDI (in system minutes)	SAIFI (no. of interruptions)
Waimate	5	11.54	0.20
Waihaouranga	6	7.72	0.04
Winchester	6	6.59	0.06
Normanby	6	5.57	0.04
Fairlie Rural	11	5.38	0.05
Woodbury	12	4.98	0.03
Holme Station	7	4.08	0.03
Geraldine TS	2	3.99	0.02
Seadown	12	3.73	0.06
Morven	9	3.53	0.03

Table 4.6 Ten worst performing feeders by SAIDI minutes in 2014/15

4.4.7 Energy delivered

Our energy delivery efficiency measures are load, loss ratio, and capacity utilisation.

4.4.7.1 Load factor

Load factor is the average load divided by the peak load in a specified time period. Load factor is derived using the equation—

$$f_{load} = \frac{kWh\ entering\ the\ network\ during\ the\ year}{(max\ demand\ for\ the\ year) * (hours\ in\ the\ year)}$$

A high load factor means power usage is relatively constant with very shallow peaks and troughs. A low load factor means that high demand is reached only occasionally. The occasional high demand is referred to as an 'n' network peak.

To service the network peak we must have available capacity to meet the seasonal, weekly, and daily electricity demand variations. Catering for peaks requires more headroom, increasing the overall network cost. Load factor is not measure of spare capacity on the network—it is a measure of the capacity required to meet the total peak load of our consumers at times of high and coincident demand.

4.4.7.2 Loss ratio

Loss ratio measures the difference between the electricity entering the system at a GXP and the energy supplied at the consumer connection point. Loss ratio is derived using the equation—

$$\text{Loss ratio} = \frac{kWh\ leaving\ the\ network\ during\ the\ year}{kWh\ entering\ the\ network\ during\ the\ year}$$

The Commerce Commission requires us to report our loss ratio each year as part of the Information Disclosure Requirements. The definition used by the Commerce Commission results in a loss ratio that comprises of both technical and non-technical losses. A technical loss is a loss that represents the electricity that is consumed during its delivery to a consumer's installations. A non-technical loss represents the inaccuracies caused by measurement and data handling, and includes losses resulting from metering and reading errors, incorrect meter installations, theft of electricity, and unread meters.

4.4.7.3 Capacity utilisation

Capacity utilisation measures the rate at which potential output levels are met or used. Capacity utilisation is derived using the equation—

$$Capacity\ utilisation = \frac{max\ demand\ for\ the\ year}{installed\ transformer\ capacity}$$

Displayed as a percentage, capacity utilisation measures the spare capacity that is in the transformers at any given point in time without incurring any additional cost. For example, if a network is running at an 80% capacity utilisation rate, it has room to increase demand by a further 20% without incurring the cost of additional assets.

4.4.7.4 Our energy delivery efficiency

The actual and projected energy delivery efficiencies are listed in Table 4.7.

Measure	2015	2016	2017	2018	2019
Load factor	70.2	70.3	70.4	70.5	70.6
Capacity utilisation	31.0	30.9	30.8	30.7	30.6
Loss ratio	3.5	3.4	3.3	3.2	3.1

Table 4.7 Actual and projected energy delivery efficiencies

Figure 4.2 shows how our energy delivery efficiency has tracked between 1994 and 2015.

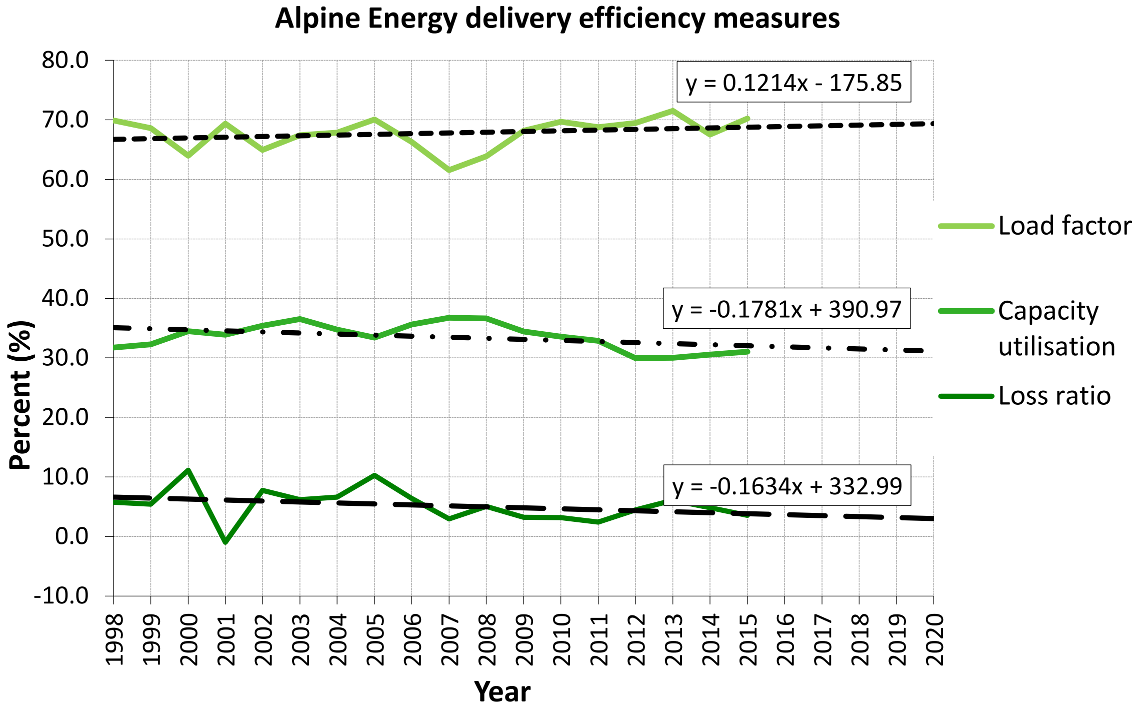

Figure 4.2 Delivery efficiency measures trend

4.5 Service levels

We recognise that the performance measures of SAIDI and SAIFI are rather academic and do not have a practical meaning for individual consumers; that is, SAIDI minutes are not the same as actual minutes without electricity supply. Accordingly, we release service levels by location to give consumers an expected level of service in the normal course of operation.

Table 4.8 shows the number of outages consumers might broadly expect in any given year by broad geographical areas.

General location	Sustained outages	Momentary outages
Dairy processing	1 outage of 2 hours every 5 years	1 outage every 2 years
Other large industrial	1 outage of 4 hours every 5 years	1 outage every year
Timaru CBD	1 outage of 3 hours every year	2 outages every year
Timaru industrial and Port of Timaru	2 outages of 3 hours every year	2 outages every year
Suburban Timaru	2 outages of 2 hours every year	2 outages every year
Waimate, Temuka, Pleasant Point, Fairlie, Geraldine, Tekapo and Twizel urban areas.	1 outage of 5 hours per year	2 outages every year
Rural areas on east coast	3 outages of 4 hours every year	4 outages per year
Rural Mackenzie Basin, including Mt Cook	4 outages of 6 hours per year	6 outages per year
Other rural areas	4 outages of 6 hours per year	8 outages per year

Table 4.8 Expected service by location

4.5.1 Consumer service level preferences

We conduct biennial surveys to establish consumer preferences for quality and security of supply. In 2014, we surveyed approximately 500 of our mass market consumers. We received 275 completed responses on perceptions of reliability, inconvenience, community disruption, and price. The key conclusions were as follows.

- Most of the consumers surveyed believe that their electricity supply reliability is similar to what it has been over the last few years, with 13% believing that reliability has improved, and 7% believing that supply reliability has worsened.
- 76% of consumers had their electricity supply interrupted for more than a few hours during the 2013 storms, with a further 9% without supply for a whole day.
- 65% of consumers experienced no inconvenience from electricity supply interruptions during the 2013 storm, while 27% experienced some inconvenience.
- 83% of consumers surveyed indicated an unwillingness to pay more to reduce the risk of prolonged supply interruptions due to storms.

The conclusion of the survey is that mass market consumers have little if any willingness to pay additional line charges to improve the storm resilience of the network.

4.6 Financial performance

Our financial performance for the year ended 31 March 2015 is shown in Table 4.9. The figures for our performance for the year ended 31 March 2016 are not available at date of publication.

Parameter	Target ('$000)	Actual ('$000)	Variance ('$000)	Variance As a %
Lines charge revenue	49,100	51,134	+2,034	+4
Operational expenditure	14,427	13,822	-605	-4
Capital expenditure	16,922	17,481	+559	+3

Table 4.9 Financial performance

4.6.1 Line charge revenue

Target revenue for 2015 was $49 million. Our total billed line charge revenue was $51 million. The result is a variance of 4%, which we do not consider material.

4.6.2 Actual vs forecast expenditure

4.6.2.1 Operating expenditure

Table 4.10 shows the variance between our budgeted and actual operating expenditure for the year ended 31 March 2015.

Operating expenditure category	Target ('$000)	Actual ('$000)	Variance ('$000)	Variance As a %
Service interruptions and emergencies	1,895	656	-1,239	-65
Vegetation management	94	172	+78	+82
Routine and corrective maintenance and inspection	2,764	3,178	+414	+15
Asset replacement and renewal	595	256	-339	-57
Expenditure on network assets	*5,348*	*4,261*	*-1,087*	*-20*
System operation and network support	3,872	5,155	+1,283	+33
Business support	5,207	4,406	-801	-15
Expenditure on non-network assets	*9,079*	*9,561*	*+482*	*+5*
Total operational expenditure	**14,427**	**13,822**	**-605**	**-4**

Table 4.10 Variance in operating expenditure as at 31 March 2015

Our Opex spending was 4% ($605k) below forecast—this variance is not considered material. However, there was material variance in Network Opex, which was 20% ($1.09m) below forecast, and within the subcategories of the expenditure. Variances are explained below.

Service interruptions and emergencies was 65% ($1.24m) lower than forecast. Forecast service interruptions and emergencies expenditure is based on historical averages of expenditure on our network following severe weather events. Unlike recent years, we did not experience severe weather events during 2014/15. Underspend, in this case, is a very good thing.

Vegetation management was 82% ($78k) higher than forecast. We have increased vegetation management on our network following the 2013 severe weather events that resulted in a large number of outages due to trees falling across our lines[30].

Routine and corrective maintenance and inspection was 154% ($414k) higher than forecast and **Asset replacement and renewal** was 57% ($339k) lower than forecast. The variances indicate a change in priorities between the two groups during the period. By increasing our inspection of assets we were able to determine that deferral of replacement and renewal was appropriate.

Non-network Opex was 5% ($482k) higher than forecast—this variance is not material. There were, however, some material variance in the subcategories of **System operations and network support** (33% or $1.3m above forecast) **and Business support** (15% or $802k below forecast), indicating a trade-off between the two categories as we embedded new systems and brought on new staff to support the growth of our network.

4.6.2.2 Capital expenditure

Table 4.11 shows the variance between our budgeted and actual capital expenditure for the year ended 31 March 2015.

Capital expenditure category	Target	Actual	Variance	
	('$000)	**('$000)**	**('$000)**	As a %
Consumer connection	5,259	4,760	-499	-9%
System growth	2,367	2,869	+502	+21%
Asset replacement and renewal	4,672	3,440	-1,232	-26%
Asset relocations	16	952	+936	+5,992
Reliability, safety and environment	3,443	3,730	+287	+8%
Expenditure on network assets	*15,756*	*15,751*	*-5*	*-0.03%*
Expenditure on non-network assets	*1,166*	*1,730*	*+564*	*+48%*
Total capital expenditure	**16,922**	**17,481**	**+559**	**+3%**

Table 4.11 Variance in capital expenditure as at 31 March 2015

[30] Many of the trees that went through our lines were outside the mandated distance of 150 metres. More information on tree clearance distances can be found on our website at http://www.alpineenergy.co.nz/sub-menu-modid-156/47-tree-requirements.

The variance between the forecast reported in our Asset Management Plan 2015–2025 and the reforecast reported here is due to the inclusion of work in progress in this AMP's figures.

Using the reforecast, the variance in **Expenditure on network assets** is 0.03% ($5k) and the variance in **Expenditure on assets** is 3% ($559k). Both variances are well within materiality thresholds.

However, there are material variances within expenditure categories. While overall expenditure is within expectations, expenditure has moved between categories as we adapt to the changing priorities throughout the period. Explanation of the expenditure category variance is provided below.

Consumer connection was 9% ($499k) lower than forecast and **System growth** was 21% ($21K) higher than forecast. Variances are due to the expenditure for the reticulation assets at the Oceania Dairy factory (ODL) being included in **System growth** rather than **Consumer connection**. For budgeting purposes, all ODL expenditure was included in Consumer connection. However, once the project was underway and works were completed, aspects of the work were assigned to the appropriate categories as works became defined

Asset replacement and renewal was 26% ($1.2m) lower than forecast—this variance reflects the need to assign our resources to the expenditure areas of greatest priority.

Asset relocations was 5,992% ($936k) higher than forecast—this variance is largely due to the relocation of a number of assets to allow for ODL's usage of pivot irrigation on a number of its fields. We do not forecast **Asset relocations** as this type of work is consumer driven and, therefore, almost impossible to forecast. Accordingly, the variance for Asset relocations is often near to 100%, though the dollar amount tends to be immaterial.

Total reliability, safety and environment was 8% ($287k) higher than forecast—this variance is not material. However, there is some material variance in the subcategories of **Quality of supply** (84% or $772k below forecast**), Legislative and regulatory** (21% or $1k above forecast), and **Other reliability, safety, and environment** (42% or $1.06m above forecast). The variances indicate our shifting priorities between categories over the period.

Non-network Capex was 48% ($562k) higher than forecast—this variance reflects work done to our offices to accommodate the growth in staff numbers over the period that we had not forecast for.

4.7 Justifying service levels

We justify our service levels based on:

- the preference of the majority of consumers for us to maintain historical levels of supply continuity and restoration for paying about the same price
- the need to prioritise network spend within the constraints of maximum line charge revenue permitted under the default price-quality path

- the physical characteristics and configuration of our network that embody an implicit level of reliability which is costly to significantly alter, but can be altered if a consumer or group of consumers pays for the alteration.
- the diminishing returns of each dollar spent on reliability improvements
- consumer specific request and ability to pay for a particular service level (e.g. uninterruptable supply)
- an external body imposing a service level or, in some cases, an unrelated condition or restriction the manifests as a service level (e.g. a requirement to place all overhead lines underground, or a requirement to maintain clearances).

Our surveys have indicated that our consumer preferences for price and service levels are reasonably static.

5. NETWORK DEVELOPMENT PLANNING

5.1 Introduction

Chapter 5 describes our planning process, forecasted load (including load projections for each GXP and related substations), and planned material Capex projects (over $300,000). Detailed information on asset renewal drivers and enhancement of the overall planning process can be found in Chapter 6—LIFE CYCLE ASSET MANAGEMENT PLANNING.

5.1.1 Background to our planning

South Canterbury has traditionally been a sheep and crop farming region, with near zero annual population growth[31]. We have historically estimated load growth by calculating a monthly growth coefficient from the previous 15 years of monthly network peak load data, before adding in step load increases when confident that load will occur.

In recent years South Canterbury has seen major changes to rural land use with many farm converting to dairy on irrigated pastures (refer Figure 5.1).

Discussions with investors reveal that growth over the next 5 to 10 years may increase peak network capacity by more than 40%[32], but investment is uncertain. And in this environment of uncertainty we are unwilling to begin material Capex projects until a firm commitment from investors is made to us in the form of capital contributions.

Figure 5.1 Most of the proposed irrigation will be supplied by the Waitaki River

[31] Based on Statistics NZ census data, average annual population growth for South Canterbury 1996–2013 has been 0.14%. Historically, South Canterbury has had low dairying levels.
[32] Discussions with investors have revealed potential future load from additional dryers at Fonterra, ODL, proposed irrigation schemes Waihao Downs and Hunter Downs, as well as from individual dairy conversions. The upper bound of forecasted load is close to 50 MW, or 40% of our present peak load.

5.2 The planning process a the strategic level

Section 5.2 summarises our planning process used to determine the material Capex spend over the next 12 months and over the next 10 years.

Figure *5.2* describes our process.

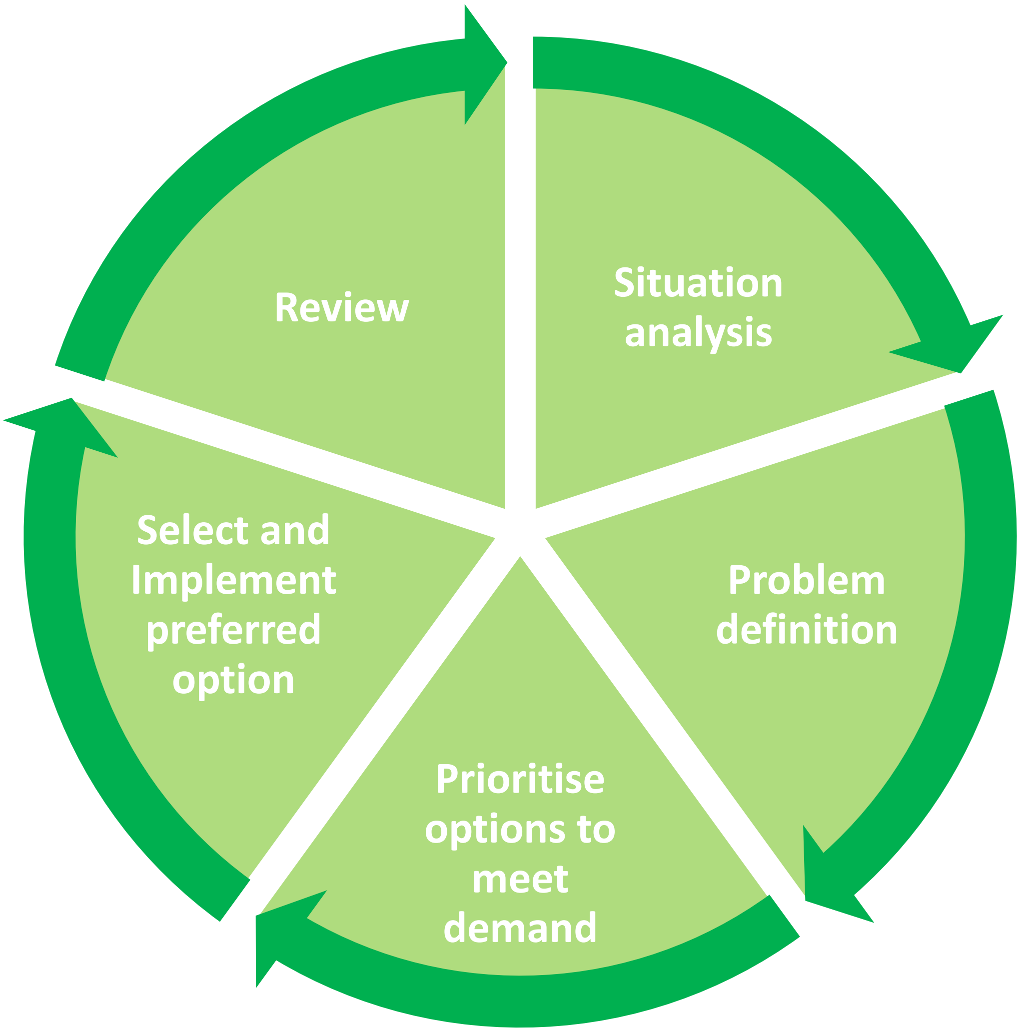

Figure 5.2 The planning process

5.2.1 Situation analysis

The first stage of the planning process is to analyse the impact of load growth on the network. The approach taken is shown in Figure 5.3.

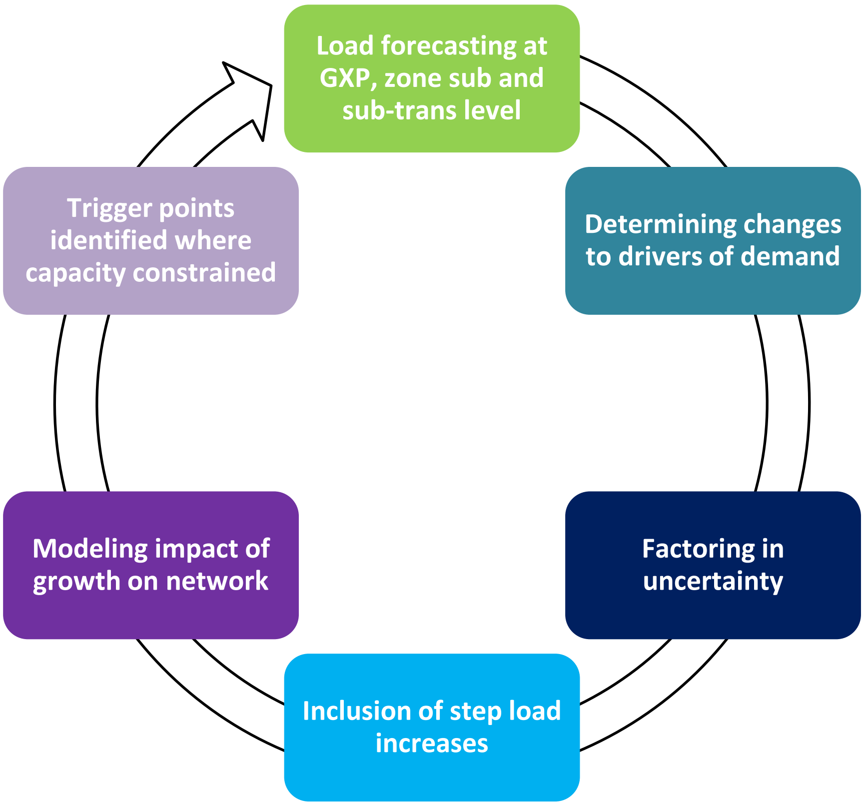

Figure 5.3 Situation analysis

5.2.1.1 Forecasting growth

When forecasting growth at substation and feeder level, we use a simple model that uses historical data to inform future growth. We use a line of best fit across historical peaks from the previous 15 years[33] before adding in step load increases when we are confident the step load increases will occur.

We are of the view that the drivers of growth will remain fairly constant for the next 10 years. However, step demand changed may increase load growth by as much as 30–40%.

5.2.1.2 Drivers for load growth

Load growth occurs in five distinct areas of our network: rural, residential, industrial, commercial, and emergent technologies (e.g. electric vehicles).

The drivers for load growth in each area are described below.

[33] Data is sourced monthly from Transpower (who meters GXPs) and reconciled against data from the Electricity Authority's reconciliation manager.

Rural load growth

South Canterbury has seen a large number of farms convert to dairy. Dairy conversions have chiefly occurred because dairy has consistently offered better return per hectare than other forms of land use over the last 15 years.

Dairying in South Canterbury often requires irrigation as the soil is naturally too dry and rainfall too low to support the grass and feed growth required. The need for irrigation is also exacerbated by the intensity of farming (i.e. cows per hectare) required to offset the large investment needed for dairy conversion.

The volume of irrigation needed will vary for each farm according to the farm's soil type, rainfall pattern, conditions of consent, and the type of irrigation installed. A farmer cannot irrigate all of the land all of the time due to water allocation restrictions so, unless water storage is available, judgement calls needs to be made as to the location, timing, and duration of irrigation. Irrigation pumps and dairy sheds require more power (network capacity) than traditional South Canterbury land use, meaning that the recent conversion to dairy has required significant network upgrades.

The drivers for rural load growth are summarised in Table 5.1 and Table 5.2.

Drivers behind dairy conversion	Effect on demand (positive or negative relationship)	Strong or weak relationship
Dairy conversions are principally driven by the return on investment from alternative uses of land—sheep, beef, cropping, etc. A more recent influence promoting dairy conversion has been a higher than average milk fat return.	ROI for alternate land use has a negative impact on dairy conversion.	Strong
Milk fat pay-out is influenced by: • Chinese demand for milk products • productivity of NZ farms re competition • developing country demand • exchange rate.	Milk fat pay-out has a positive impact on dairy conversion.	Strong
Resource consents: • aggregate nitrate levels • water available for consent.	Resource consents have a positive relationship with dairy conversion. A restriction on consents will limit number of conversions.	Strong
Availability of credit	Positive	Weak
Speculation	Positive	Weak

Table 5.1 Drivers behind dairy conversions

Drivers influencing irrigation	Effect on demand for irrigation	Strong or weak relationship
Rainfall	Negative correlation, but extended periods of rainfall impacts soil moisture and soil moisture impacts irrigation load. The first day of rain sees high demand for power as plants are more receptive to water uptake.	Weak
Moisture levels in soil	Dry porous soils will need to be irrigated more.	Weak
Type and number of irrigators	Fewer irrigators may mean land irrigated regardless of rain or soil type.	Weak
Intensity of farming (cows per hectare)	Positive; more feed required leading to more irrigation.	Strong
Conditions of consent	Negative; a restriction on consents will limit water available for irrigation.	Strong

Table 5.2 Drivers behind intensity of irrigation at farm level

Residential load growth

The traditional driver of residential growth has been population growth. From 1996 to 2013, South Canterbury population growth was 0.14% p.a. Recently, other drivers have been impacting on the use of electricity, including:

- environmental restrictions on the use of open fires
- the price and availability of alternative energy sources
- better insulation on newly built houses.

The exact impact of these drivers remains unclear. Heat pumps are more efficient than other forms of electric heating, leading to a decrease in demand. However, the change from log fires to heat pumps increases the amount of electrical heating on the network, leading to higher demand.

Industrial and commercial load growth

Local economic growth is the main driver behind load growth on our network. We include growth as step demand increase in our planning once we are confident that load will occur.

Electric vehicle (EV) growth

The global trend towards lowering vehicle emissions, climate change, the relatively high price of hydrocarbon fuel when compared with electricity, and increasingly competitive EV technology compared with conventionally fuelled vehicles, has generated renewed interest in EVs. Some commentators believe that EVs will become economic in New Zealand by 2019[34]. Give the approximately 8:1 cost ratio between hydrocarbon and electricity fuels, and the lower maintenance cost of EVs, the recent drop on oil prices is unlikely to have a significant impact on the direction of global car makers in the future.

EV growth may be influenced by hydrogen generation becoming more viable and used for motor vehicle fuel. However, hydrogen is not environmentally friendly at present as it is produced from methane. The use of biogas from garbage recycling stations may improve the environmental friendliness, though it is doubtful whether there would be enough methane produces to affect EV dominance. As of 2014, it is reported that there are only 12 public hydrogen refuelling stations in the USA compared with 10,000 EV charging stations. In addition, there are far more companies investing in electric cars than in hydrogel fuel cell vehicles. In 2015, new EV models were announced to add to the many already in production worldwide.

The worldwide registration of EVs reached 740,000 in 2014, with 320,000 new registrations in that year, resulting in 74% growth. In 2015, the world car and light conventionally fuelled vehicle fleet size was estimated at 770,000,000 and growing (one estimate has the global fleet reaching 2 billion by 2035. If the growth rate of EV registrations continues at 76%, the EV proportion of the world fleet would be 211 million by 2025. In reality, we can expect the present exponential growth to become a straight line increase in about 2020, turning into an S curve once EV production has overtaken conventional vehicles and market saturation is reached. Complete replacement of the fleet with EVs could take another 10–20 years, as the legacy hydrocarbon vehicles age and are replaced.

The uptake of EVs in New Zealand is likely to lag behind the rest of the developed world if support for recharging stations is not forthcoming.

PV growth

PV growth is driven by consumer interest in ‘greener’ technology, electricity prices, and set up and maintenance costs of photovoltaic systems. In the future, cheaper battery technology will encourage greater uptake than is seen today.

Drivers which could reduce uptake of PV include the recent reduction in electricity buy-back price by some retailers and cheap hydro generation. Hydro generation is abundant in New Zealand and, due to its negligible carbon footprint, does not place pressure on the government to promote ‘greener’ forms of generation. Solar hot water has received less media attention than PV, but could have an impact on the network in the future if PV looks less promising

[34] EVs will become more economic when battery technology improves from the present lithium ion battery.

Negative load growth

Negative load growth could occur due to installation of distributed generation (DG), particularly from photovoltaics (PV) on sunny days. The impact of DG would be amplified by the installation of battery storage systems, enabling the DG to supply the network during periods of peak demand.

At present, the influence of emerging technologies on load growth is not significant. However, the uptake of PV in South Canterbury since 2010 has been exponential. If such growth continues, it could become a significant influence in the next 10 years. Continued PV growth is expected due to the exponential improvements in and decreasing prices of PV and battery storage technology, and the anticipated increase in consumer interest.

South Canterbury does not have the best sunshine parameters in New Zealand, averaging between 1,751 and 2,000 sunshine hours per year compared to Nelson/Marlborough's average of over 2,250 hours[35]. However, South Canterbury compares favourably with Western Europe. Table 5.3 below provides some examples.

Location	Sunshine hours per year	New Zealand equivalent
Morocco	3,146	Equivalent latitude to Northland
Spain (Madrid)	2,691	
Sweden (Stockholm)	1,821	
France (Paris)	1,799	
France (North)	1,400–1,700	
France (Central, Northwest, Southwest)	1,700–2,000	Equivalent latitude to Southland
France (West, South inland Southeast)	2,000–2,300	Equivalent latitude to South Canterbury
France (Mediterranean)	>2,300	
Germany (Berlin)	1,650	
UK (England)	1,475	
UK (Scotland)	1,175	

Table 5.3 Sunshine hours in Western Europe

It should be noted that most of the sunshine hours in Western Europe are recorded during the warmer nine months of the year, while South Canterbury (and the East Coast of the South Island in general) has significant cloud-free days during winter months. This

35

difference is due to New Zealand's changeable maritime environment as opposed to Western Europe's more stable, seasonal continental climate.

Use of multivariate models

It is important to identify the main drivers of load growth when forecasting. Ideally, a complex multivariate model that identifies and includes drivers that have an observable relationship with load growth would be developed. However, initial investigations onto rural demand for electricity have found it difficult to show observable relationships between the most obvious drivers of irrigation (the main drivers of future growth), such as temperature or rainfall. The volume of irrigation on a farm depends on a number of factors, such as conditions of the resource consent, existing soil moisture, substrate type, etc. A farmer in one region of South Canterbury may have different drivers for irrigation than a farmer in another region.

In short, the relationship between suspected key drivers of irrigation and the volume of irrigation is considered too complex to model accurately. Instead, a simple model that forecasts growth based on historical data is used, with the assumption that historical complex relationship will continue into the future.

Where it is known that there will be a change in a key driver, such as the number of resource consents issued, our planning team factors the change into the growth forecasts based on simple historical forecasts.

Use of outside consultants

In 2011 we recruited Sapere Group to model the relationship between rainfall and irrigation. Sapere found 'a weak negative correlation between rainfall and irrigation (-20%) which reflect a high degree of randomness'. Sapere concluded that, due to the number of drivers for irrigation, 'specifying [the relationship between irrigation and rainfall] with a high degree of certainty proves problematic'.

5.2.1.3 Inclusion of step demand increases

We include step increases in load when proposed load is certain. If the step in demand is material, we will not proceed beyond the conception planning stage until a capital contribution has been paid.

Often we are unaware of new load requirements until a customer requests to connect. In some cases, upgrades required to enable a connection take longer than a customer expects. To overcome this timing issue, we are looking at ways to inform and educate local investors about the notice periods necessary for us to complete the required work.

5.2.1.4 Planning assumptions and impact of uncertainty

Table 5.4 describes how we factor uncertainty into the planning process.

Assumption	Uncertainty	Impact on asset management
Consumers will continue to use and pay for energy supplied by our network. • TIM and TKA subs will stay winter peaking and load will grow at 1-2% p.a. • Summer peaking subs will have load growth around 3% p.a. driven by agricultural requirements. •	Consumption patterns changing due to economic, political, or environmental changes.	Reduced revenue could impact on service levels.
Load growth forecasted accurately based on prior consumption.	A change to one or more key variables that influence consumption from the time period the load forecast was based on.	Changes in investment direction and spending could occur as new information comes to light. An annual update of the AMP is needed to keep account of changes.
Return on investment is adequate to meet stakeholder requirements.	Unforeseen increase in costs or decrease in revenue occurs.	Capex and Opex could alter to meet shareholder requirements.
The regulatory framework will continue around its present format.	There may be major shifts in regulatory thinking, possibly from political change.	Could lead to greater expenditure to meet and understand compliance, as well as changes to the AMP.
The level of capital expenditure will meet stakeholder requirements for safe, efficient, reliable, and cost effective energy delivery.	Uncertain events may force an increase in expenditure.	Level of Capex may have to be altered to meet stakeholder requirements.
The discount factor used to estimate present value of future cash flows will not significantly change.	There will be a change in the treasury outlooks, inflation, etc.	The present value of cash flows will have to be updated as new financial information comes to light.

Assumption	Uncertainty	Impact on asset management
Environmental legislation in relation to water rights and air quality will not significantly change.	A change in allocation of water will impact on irrigation and load requirements, while air quality will impact on the use of heat pumps.	Capex forecasts will have to alter to cater for changes in load demanded.
There will be no new unplanned large loads or generation appearing on our network.	New unplanned load or generation appears on the network.	Changes to investment and Capex planning required.
Our planning and prudent investment takes into account impact of natural events on the network.	The impact and timing of a natural event is beyond prudent planning and investment.	Could lead to significant changes across asset management and expenditure in particular.
The use of distributed generation will not increase significantly in the medium term.	The uptake of DG will increase significantly because of a reduction in costs and/or an increase in return from generation. The reverse also applies if returns to DG drop.	May require further investment and a change in how costs are recovered from DG owners, and how benefits are given to DG owners.
There will be a constant load factor throughout forecast period.	Load factor will change.	May have insufficient capacity for unplanned load, leading to changes in planned Capex.
Diversity across network will remain constant.	Diversity will change.	May have insufficient capacity for unplanned load, leading to changes in planned Capex. May cause increased maintenance costs leading to changes in planned Opex.

Table 5.4 Significant assumptions and the effect of uncertainty on planning

5.2.1.5 Use of software to model impact of growth

Growth levels and feeder data, such as connected loads, are entered into various modelling software to model the impact of growth on the network at GXP and feeder level. Trigger points (capacity constraints) are identified and include ampacity, voltage drop, or summed network demand.

5.2.1.6 Identification of trigger points

Load growth eventually results in asset operating parameter trigger points being reached for location, capacity, reliability, security, condition, or voltage.

If a trigger point is reached, we activate one or more of a range of network development options to bring the asset's operating parameter back within an acceptable range. For example, Capex projects to extend, upsize, or renew an asset enable that asset to meet the new level of demand. Consequently, the asset's trigger points are adjusted to correspond to its new operating parameters. More detail on this topic can be found in Chapter 6—LIFE CYCLE ASSET MANAGEMENT PLANNING.

5.2.2 Problem definition

Once a trigger point is identified, we define the issues behind it, before considering options to meet demand. By defining the issues behind a trigger point, we avoid a 'goal trap' and explore options that previously were not apparent. All options considered must align with our mission for safe, reliable, and efficient energy delivery and infrastructure services.

When exploring various options we must factor in the time needed to plan and build so that projects are completed on time. For example, some power transformers can take a year to source, while projects requiring changes to the transmission network can take up to five years to facilitate.

As network assets grow with increased load, the Opex life cycle tasks of operation and maintenance will grow in number and complexity. It is, therefore, important that planning and design options are chosen that ensure lower operational and maintenance costs. Although such options may not have the lowest Capex cost, they are essential for evolving a more efficient and economic network.

5.2.3 Prioritisation of options

Table 5.5 described various options considered when capacity is exceeded or expected to be exceeded. The options are listed in order of preference.

Option	Description of option	Example of a possible option
Do nothing	Simply accept that one or more parameters have exceeded a trigger point. In reality, the do nothing option would only be adopted if the benefit-cost ratio of all other reasonable options were unacceptably low and if assurance was provided to the CEO and the Board that the do nothing option did not represent an unacceptable increase in risk.	The voltage at the far end of an 11 kV overhead line falls below the threshold for a few days per year—the benefits (including avoiding the consequences) of correcting such a constraint are simply too low.

Option	Description of option	Example of a possible option
Operational activities	Switching the distribution network to shift load from heavily-loaded to lightly-loaded feeders to avoid new investment, or introducing a voltage regulator or capacitor bank to mitigate a voltage problem. A downside is that switching may increase line losses and reduce security of supply.	
Influence consumers	To alter consumer consumption patterns so that assets perform at levels below the trigger points.	Shift demand to different time zones, negotiate interruptible tariffs with certain consumers so that overloaded assets can be relieved, or assist a consumer to adopt a substitute energy source to avoid new capacity.
Construct distributed generation	An adjacent asset's performance is restored to a level below the trigger points. Distributed generation would be particularly useful where additional capacity could eventually be stranded or where primary energy is underutilised.	Water being released from a dam that could be used in a hydro generator, or install a high pressure boiler for an electricity turbine, then use medium pressure outflow for industry.
Modify an asset	The trigger point will move to a level that is not exceeded. Essentially a sub-set of retrofitting, that generally involves less expenditure. Modifying an asset is more suited to larger classes of assets such as 33/11 kV transformers.	By adding forced cooling.

Option	Description of option	Example of a possible option
Retrofitting	Retrofitting high-technology devices that can exploit the features of existing assets.	
Install new assets	A greater capacity will increase the assets trigger point to a level at which it is not exceeded.	Replacing a 200 kVA distribution transformer with a 300 kVA transformer or replacing light conductor with a heavier conductor. We research likely ground conditions to rate cables as high as possible to allow maximum power flow.

Table 5.5 Options for capacity constraints

The preferred option is chosen during planning sessions with the network, asset, and operations managers.

We are presently implementing a software-based decision making tool that will assess and balance competing demands for growth, safety, and financial return, to identify the best options. Combined with the experience and knowledge of our engineers the tool will greatly enhance the network planning process. For more information please see Section 8.3—Continuous improvements to our asset management system.

5.2.4 Implementation

Once the preferred option is chosen, the network, asset, and operations managers will include the option (project) in the works plan to be incorporated into the AMP and budgets for approval by the CEO and the Board of Directors.

Projects included in the works plan are listed in priority order in Table 5.6.

Criteria for assessing options	Description
Safety	Projects that require execution to improve safety and/or remove hazards. Criteria include: public safety, workplace safety, and network operating safety.
Reliability	Projects that improve network resilience in the face of faults, undesirable events, and general use. Criteria include: improve network condition, interoperability, adaptability, flexibility, ease of use, and maintainability.

Criteria for assessing options	Description
Efficiency	Projects that improve the capacity of the network to meet stakeholder needs. Criteria include: network operating performance, organisation of network assets, improvement of network design, and a reduction in maintenance and operating time through selection of maintenance-free equipment with minimum operation requirements.
Economy	Projects that produce the best return in terms of network improvement for funds expended and provide a reduction in life cycle costs through selection of "maintenance-free" equipment with lowest inspection and operation overheads.

Table 5.6 Criteria for prioritisation of different options

Once accepted into the Capex works plan, as listed in Appendix B and Appendix C, the project will proceed as described in Figure 5.4.

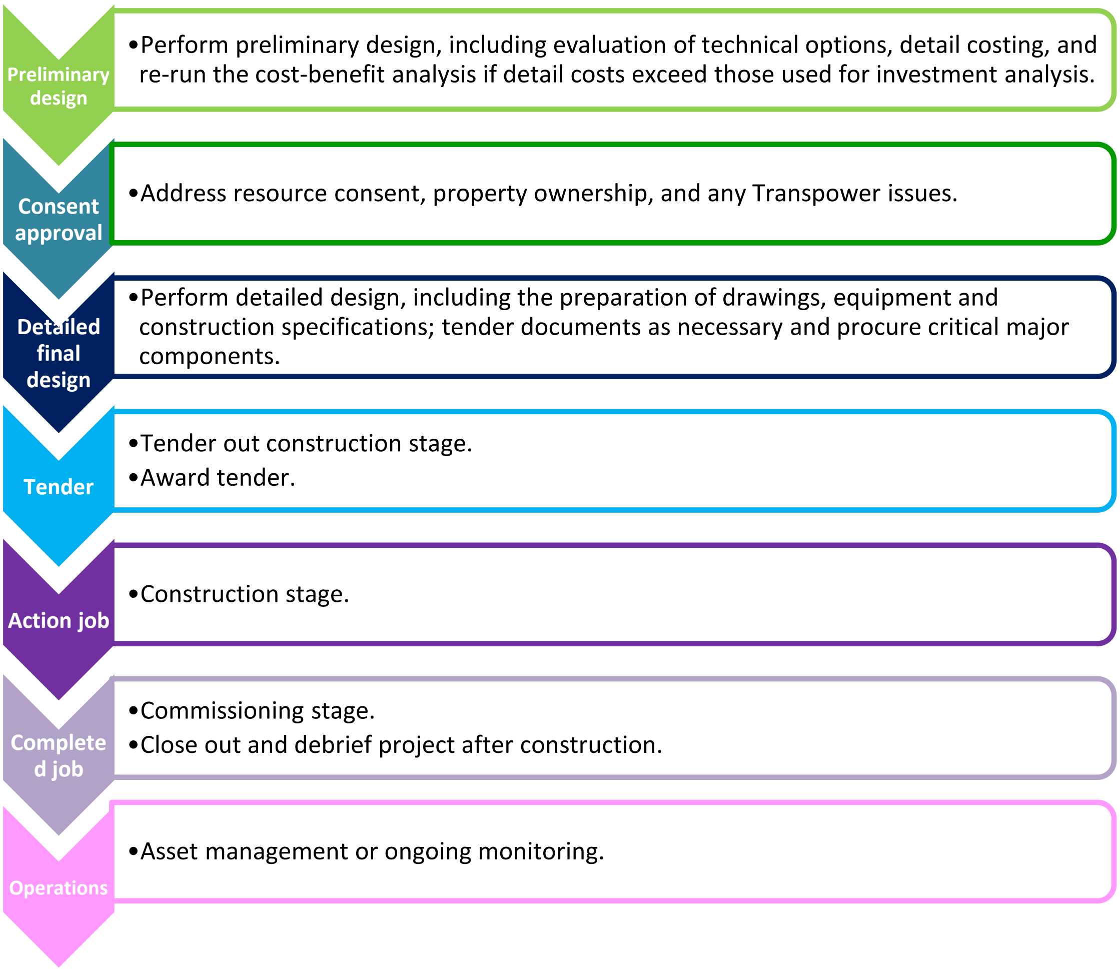

Figure 5.4 Project completion procedure

5.2.5 Review

Plans are reviewed to compare progress against goals and to check planning assumptions. New information on step load increases may result in the addition or subtraction of future loads from the plan. A review of our planning process is presently under way. For more information please see section see Section 8.3—Continuous improvements to our asset management systems.

5.3 Demand forecasts on the network

Demand forecasts for GXPs, sub-transmission, and zone substation assets can be found in the AMP—Major Assets.

Residential demand is forecasted by extrapolating a trend line from the last 16 years of monthly peak demand at GXP level and determining historical growth. The likely impact of population changes, environmental legislation on heating and significant economic changes, is factored in by the planning team. The global financial crisis, for example, is deemed to have had a significant negative impact on energy consumption from 2009 to 2012.

Large industrial load forecasts also rely on information from industry for step demand changes. For more detail, please see Section 5.3.1—Inclusion of step demand increases.

Figure 5.5 illustrates total system load growth on our network.

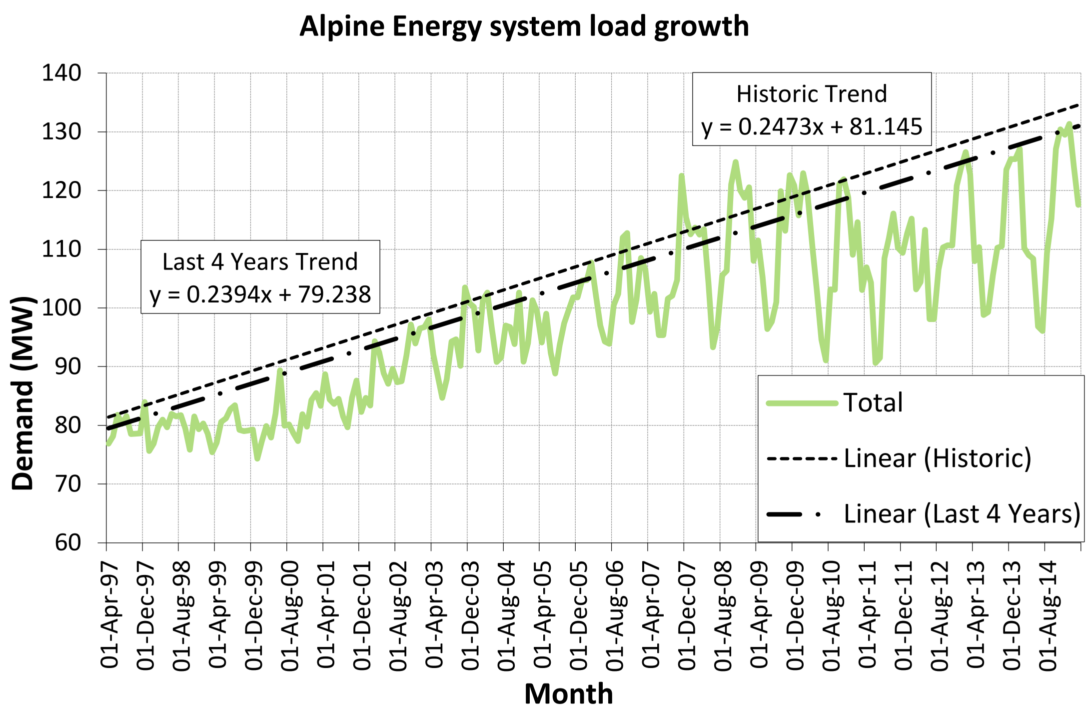

Figure 5.5 Network load growth

Figure 5.6 and Figure 5.7 show historical trends of anytime maximum demand and the total maximum demand growth rate for each GXP (shown by the dotted line in each case).

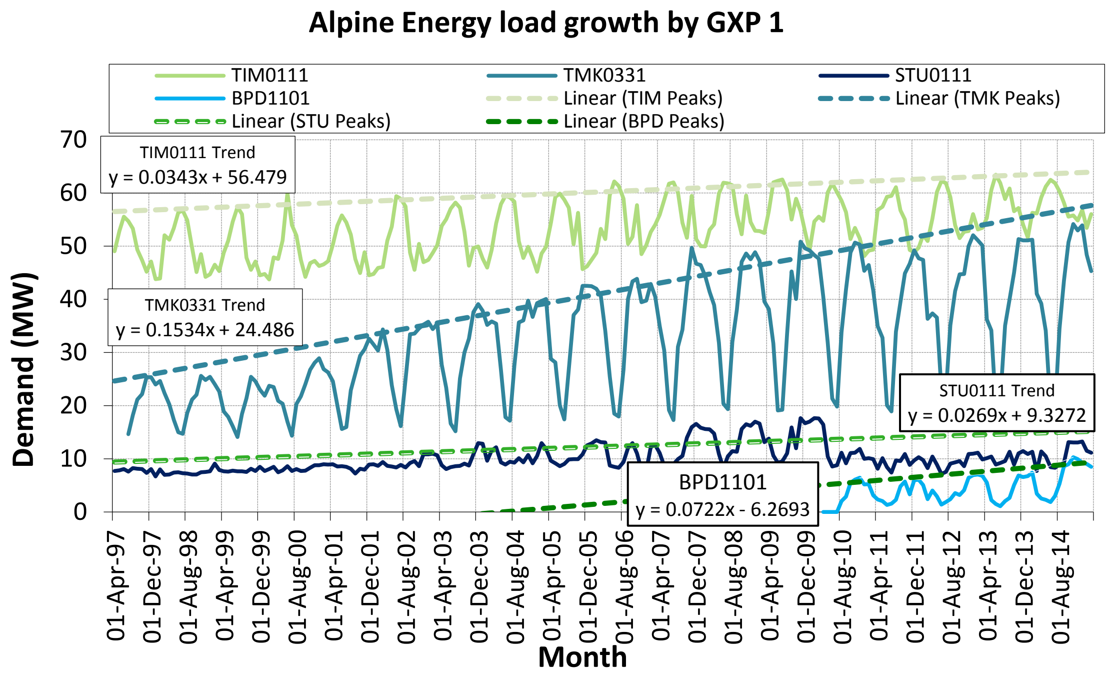

Figure 5.6 Load growth by GXP (1)

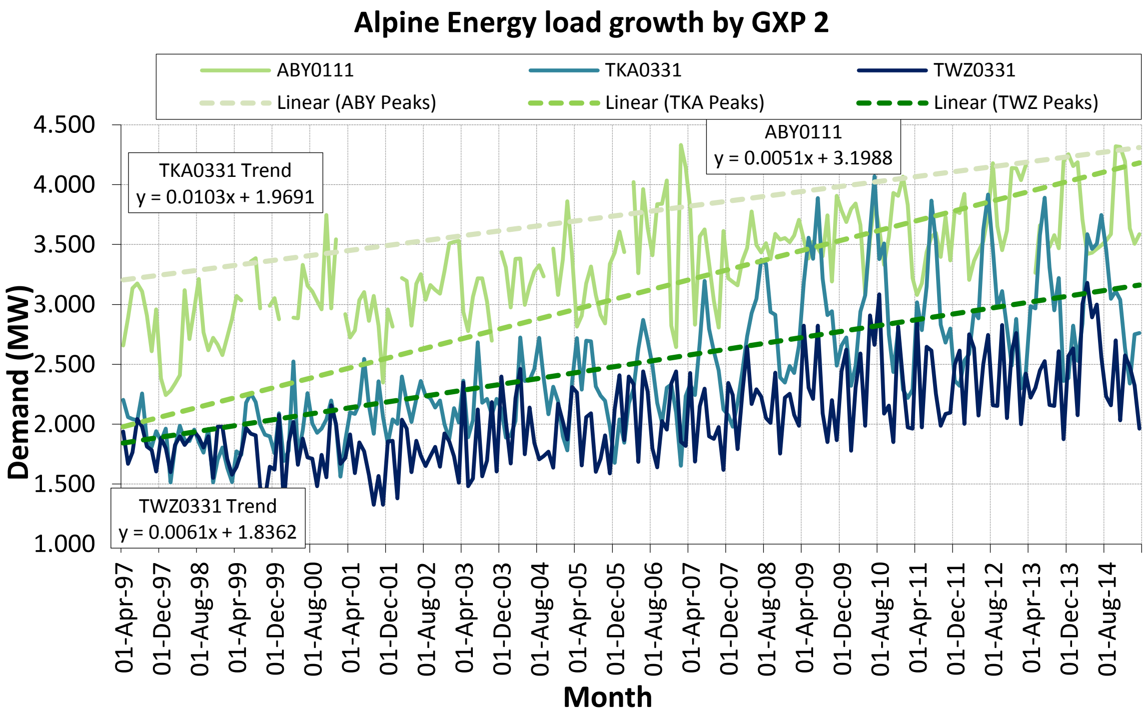

Figure 5.7 Load growth by GXP (2)

The stagnated growth between 2009 and 2012 can be attributed, in part, to the international financial crisis and its effect on development and the business climate in New Zealand.

The data in each of the graphs is summarised in Table 5.7. The figures reported here are current to March 2015 and are based in the highest single half-hour maximum rather than an average of the 12 highest peaks. The trend is over the last 15 years.

GXP	Half hour max demand	Monthly growth (MW)	Annual growth (MW)	Annual growth (%)
ABY0111	4.32	0.005	0.061	1.417
BPD1101	10.28	0.072	0.866	8.430
STU0111	13.22	0.027	0.323	2.441
TIM0111	62.48	0.034	0.412	0.659
TKA0331	3.75	0.010	0.124	3.298
TMK0331	54.11	0.153	0.841	3.402
TWZ0331	3.18	0.006	0.073	2.302
Total	**131.1**[36]			

Table 5.7 Historical demand and growth

5.3.1 Inclusion of step demand increases

The planning team must also take into account probable step demand loads that have been communicated to use by Transpower and/or industry. Step demands listed in Table 5.8 are incorporated into our GXP load growth projections, along with the assumptions described earlier.

Project	Demand (MW)	Year	GXP
Baylyn Farms	0.6	2015	BPD
Clandeboye C21 stage 2	1.5	2015	TMK
Ecotech plastics	0.8	2015	NST/TIM
Holcim Cement	2.5	2015	GRM/TIM
Holcim Cement	1.5	2015	NST/TIM
Hydro Grand	0.5	2015	HNT/TIM
Juice Products NZ	1	2015	TIM
Rangitata Irrigation	3	2015	RGA/TMK
Show Grounds St 1	1	2015	TIM

[36] This total is our total coincident maximum demand, not the sum of the non-coincident GXP demand.

Project	Demand (MW)	Year	GXP
Simons Pass Irrigation	2.5	2015	TWZ
Tekapo Village Development	0.5	2015	TEK
Waihao Downs Irrigation St 1	3.2	2015	BPD
Baylyn Farms	1	2016	BPD
Haldon Irrigation	0.5	2016	TWZ
Ivey Irrigation	0.2	2016	TWZ
OHC Irrigation	0.8	2016	TWZ
Pukaki Irrigation	2.5	2016	TWZ
Pukaki Farming following Irrigation	1	2016	TWZ
Show Grounds St 2	1	2016	TIM
Tekapo Village Development	0.5	2016	Tekapo
Baylyn Farms	1	2017	BPD
Fonterra dryer by 2019 (media) put at 2017	6	2017	STU
Oceania Dairy Ltd Stage 2U & 2L	3	2017	CNR
Show Grounds St 3	1	2017	TIM
Waihao Downs Irrigation St 2	3.2	2017	BPD
Hunter Downs Irrigation	34	2018	BPD/STU/STA
Oceania Dairy Ltd Stage 3 Dryer 2	2.5	2019	CNR
Oceania Dairy Ltd Stage 4	2.5	2020	CNR
Fonterra dryer by 2024 (media) put at 2022	6	2022	STU

Table 5.8 Projects adding step demand (by GXP)

5.3.2 Estimated demand at GXP level

Once step demand loads are factored into our planning models, we estimate demand at GXP, zone substation, and feeder level. Summaries of demand at zone substation and feeder level are given in Section 5.3.3—Estimated demand at zone substation level. Information on planning at the GXP level can be found in the AMP—Major Assets and are summarised in Table 5.9

GXP substation (Season peak)	Forecast growth trend (Total MW MD) for the year ended 31 March										
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ABY (summer)	4.2	4.3	4.4	4.5	4.5	7.6	7.8	8.0	8.2	8.4	8.6
BPD (summer)	15.6	20.2	26.4	26.8	19.0	19.4	19.8	20.2	20.6	21.0	21.4
CNR (all) (potentially off BPD – included)	0.0	0.0	0.0	8.1	9.6	9.6	9.6	12.1	12.1	14.6	14.6
OAI (summer)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	53.7	54.4	55.1	55.9
STA (summer)	0.0	0.0	0.0	0.0	20.7	21.5	22.0	22.6	23.1	23.7	24.3
STU (summer)	12.1	12.2	18.4	18.7	25.1	25.5	25.8	32.1	32.6	33.1	33.7
TKA sum (autumn/spring)	5.2	5.8	6.0	6.1	6.3	6.4	6.6	6.7	6.9	7.1	7.3
TEK Village	3.8	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.3	5.4
Mt Cook and GTN	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9
TMK (summer)	60.2	62.5	63.7	65.0	66.3	67.6	69.0	16.6	17.3	18.0	26.8
TIM 110 kV (summer)	126	130	133.	135	134	139.	140.5	89.0	90.6	92.2	101.8
TIM 11 kV (winter)	70.3	72.2	73.8	74.5	72.1	72.8	71.6	72.2	72.9	73.6	74.3
PAR	9.04	9.23	9.41	9.60	8.59	8.76	8.94	9.12	9.30	9.48	9.67
PLP	5.9	6.0	6.1	6.2	6.3	6.5	4.6	4.7	4.8	4.9	5.0
TWZ sum (autumn/spring)	3.2	3.7	8.1	9.5	9.9	10.4	10.8	10.9	10.9	11.0	11.1
TVS Village	3.7	8.1	9.6	10.0	10.5	10.9	11.3	11.4	11.5	11.6	11.7

GXP substation (Season peak)	Forecast growth trend (Total MW MD) for the year ended 31 March										
Irrigation on 33 kV	0.4	4.7	6.1	6.4	6.8	7.1	7.5	7.5	7.5	7.5	7.5
WHO (summer)	0.00	0.00	0.00	0.00	59.1	59.9	60.7	70.1	71.1	74.6	75.7

Table 5.9 Load growth by GXP

5.3.3 Estimated demand at zone substation level

Information on planning at zone substation level can be found in the AMP—Major Assets. Demand growth at zone substation level is summarised in Table 5.10.

Zone sub	2016 MW	Ten-year rate and nature of growth	2026 MW	Provision for growth
ABY 11 kV board	4.20 (summer)	1.59% historical on ABY. Irrigation and dairying activity, residential load, small subdivision development.	5.0 (summer) 8.4 (with Raincliff/ Totara Valley)	Transpower asset under its management. Overall load not expected to breach Transpower's capacity unless Raincliff/ Totara Valley built.
FLE	2.37 (winter)	1.57% historical on ABY. Residential load, small subdivision development.	2.9 (winter / shoulder)	Regulator upsizing or transformer with OLTC - expect demand to grow from current demand of 2.3 MW to 2.9 MW over the planning period.
BPD	15.6 (summer)	4.8% per year expected. Residential load. Dairy and irrigation development.	BPD 21.4 CNR 14.6 (summer) Sum 36.0	Increase substation assets to offload STU and provide more security and capacity. Work is needed to carry load, which depend on mooted projects progressing.
CNR	3.6 (summer/ winter)	Dairy processing.	14.6 (summer/ winter)	Assumption is to prepare site for two dryers/lactose and UHF products off BPD 33 kV initially with later extensions for two dryers forcing the primary potential for the site to 110 kV. AEL have included for four 3.5 MW dryers and other sundry loads in planning.
CD1 & CD2	0 (summer)	3.6 % per year expected at RGA. Clandeboye growth comes from steps in dairy processing.	56 (summer)	Built to suit 10 year forecast.
STA	0 (summer)	3.6 % per year expected as STU Rural development.	24.3 (summer)	Build to suit 10 year forecast.
STU	11.4	3.2% per year	33.7	Transformer upsizing required pending

Zone sub	2016 MW	Ten-year rate and nature of growth	2026 MW	Provision for growth
	(summer)	expected as TMK Residential load. Dairy and Irrigation development (not including step changes).	(summer)	load split for Hunter Downs between STU and STA. 11 kV switchboard upsizing required after 24 MVA.
TEK	3.2 (winter /shoulder)	3.9% historical on TEK. Residential load. Tourism development.	5.4 (winter /shoulder)	Transformer being changed out in 2015 to 5/6.25 MVA.
HLB	0.2 (est.) (winter /shoulder)	3.9% historical on TKA. Residential load. Tourism development.	(winter /shoulder)	Minimal unless lines away rebuilt. If irrigation expands toward Haldon then it is likely that supply will come from TWZ. HLB would be retained for Lilybank.
BML	0.3 (est.) (winter /shoulder)	3.9% historical on TKA. Residential load. Tourism development.	(winter /shoulder)	Minimal unless lines away rebuilt. If irrigation expands toward Simon's Pass then it is likely that supply will come from TWZ. BML may be decommissioned. Close in loads can be fed at 11 kV.
GTN	0.3 (est.) (winter /shoulder)	3.9% historical on TKA. Residential load. Tourism development.	(winter /shoulder)	Consideration given to decommissioning sub and replacing downstream dist. transformers with 33 kV. Saves need to install OLTC transformer.
UHT	1.1 (est.) (winter /shoulder)	3.9% historical on TKA. Residential load. Tourism development.	1.9 (winter /shoulder)	Transformer likely to need a change out in planning period.
TMK	60.2 (summer)	3.6% historical on TMK. Residential load. Dairy and irrigation development. Dairy processing.	26.8 (summer) Provided OAI offloads bulk of TMK. 82 if not.	Load growth due to expansion at Clandeboye, which is not yet confirmed. More of a focus put on STU at present. Rangitata South Irrigation being commissioned, possibly 4 MW more to be loaded. Transmission solutions being discussed with Transpower.
CD1 & CD2	30.4 (summer)	3.6% Stepped to suit process expansion and any new dryer.	35 (summer) 43 With new dryer	Substation and sub-transmission capacity available. Additional CBs at substations and 11 kV cabling to new RMU and dist txs required – expect demand to grow from current demand of 30 MW to 43 MW by the end of the planning period. With careful load transfers existing assets can meet demand and retain N-1 security.
GLD	6.1 (summer)	3.6% historical on TMK. Residential load.	7.9 (summer)	Local concern may lead to a second 33 kV circuit to provide N-1 security—expect demand to grow from current

Zone sub	2016 MW	Ten-year rate and nature of growth	2026 MW	Provision for growth
		Dairy and irrigation development.		demand of 6.5 MW to 7.8 MW by the end of the planning period. AEL installed RMU to break rural load off CBD—will improve reliability and allay some concerns.
RGA	9.8 (summer)	3.6% historical on TMK. Residential load. Dairy and irrigation development.	20 (summer)	Second 33 kV circuit installed to provide improved security to essential loads. Expect demand to grow from current demand of 9.8 MW to 20 MW by the end of the planning period. Note some of RGA load can be transferred to TMK and GLD as a temporary measure.
TIM	62.2	0.7% (winter).	74.3 (winter)	0.7% historical; some steps expected to come from residential growth, heat pump uptake, and industry growth (Washdyke).
TIM CBD	39 MW (winter)	0.7% historical on TIM.	45 (winter)	None required for local assets as substation and sub-transmission capacity is available. Additional CBs at substations and 11 kV cabling to new RMU and distribution transformers required. Expect demand to grow from present demand of 39 MW to about 45 MW by the end of the planning period. Existing assets can meet demand and retain N-1 security.
PAR	8.7 (summer)	3.2% per year expected on TMK until STA GXP built. From then 2% Residential load, dairy and irrigation development.	9.6 (summer). 11 If STA GXP not built by then.	Up-sizing of sub-trans lines required to retain full N-1 security—expect demand to grow from current demand of 8 MW to 9 MW by the end of the planning period. Acceptable security for the major meat processing works is required. Some security via 11 kV back up from STU and TIM. Possible partial off load to new STA GXP as it eventuates.
PLP	4.7 (summer)	4.62% per year expected as TMK experiences residential load growth, and dairy and irrigation development.	3.8 (summer). 8 If Totara Valley not built.	Existing transformer rated for the period. Some security via 11 kV back up from ABY, TIM, and TMK. Possible substation built nearer irrigation load at Totara Valley to improve security.
TVS	3.3 (shoulder)	2.26% historical on TVS. Residential load, large scale subdivision, dairy and irrigation development.	4.2 (shoulder)	Possibly rebuild substation in conjunction with developer to free land. Extend 33 kV line to new irrigation development and install smaller dedicated substations.
WHO	0 (summer)	3.6 % per year expected at WHO as per present growth	76 (summer)	Build to suit 10 year forecast.

Zone sub	2016 MW	Ten-year rate and nature of growth	2026 MW	Provision for growth
		at STU and BPD.		

Table 5.10 Zone substation demand growth

5.3.4 Estimated feeder demand

Due to the large number of 11 kV feeders on our network, maximum feeder demand is listed in Appendix A—SUMMARY OF 11 kV FEEDERS.

5.3.5 Effect of GXP forecasts on supply security

The continuing load growth at ABY, BPD, STU, TMK, and TIM GXPs, as well as forecasted load increases at TKA and TWZ, will cause capacity constraints within the AMP planning period. The AMP—Major Assets has more information on network constraints. A summary of how we provide for growth is provided in Table 5.11.

GXP	Rate and nature of growth	Provision for growth
ABY	Med – rural	GXP investment if Totara Valley connected
BPD	High – rural, industrial dairy factory	New investment to secure the energy needed off the grid
STU	High – dairy and irrigation Med – dairy processing	New investment to secure the energy needed off the grid
TKA	Med – subdivision and tourism business	Need supply transformer at TKA to be re-rated to its 10 MVA, presently 4.3 MVA
TMK	High – rural and industrial	GXP investment
TIM	High – industrial / commercial	GXP investment
PAR	High – dairy and irrigation	Sub-transmission investment
PLP	High – dairy and irrigation	Investment at Totara Valley – Zone substation and sub-transmission
TWZ	Med – rural and subdivision	GXP investment, rural investment to take electricity to areas presently unserved

Table 5.11GXP growth rate and provisions made

5.4 Effect of constraints on planning

A summary of network constraints is provided in Table 5.12. A full description of the constraints can be found in the AMP—Major Assets.

Constraint	Description	Intended remedy
Waimate Area—Holistic	Lack of capacity for BPD, STA, STU.	Work with Transpower on the Lower Waitaki Project to ensure capacity is made available a.s.a.p..
STU GXP Supply Security to 110 kV bus	Upgrade N security to N-1.	From Feb 2010 110 kV bus is closed during peak dairy season—partial fix during high cost part of year. Ultimate, new investment in transmission line. Transpower discussion via Lower Waitaki Project.
STU GXP Supply Security via transformer capacity	Upgrade N security to N-1.	Interim, partial off load to BPD substation (2010). Ultimate, new investment in Transformers and unitised HV CBs.
BPD GXP Supply Security at 110 kV	Upgrade N security to N-1.	Work with Transpower on the Lower Waitaki Project to ensure capacity is made available a.s.a.p.
BPD GXP Supply Security via transformer	Upgrade N security to N-1.	As the demand grows install second transformer (timing uncertain—allign with Lower Waitaki Project).
STA, WTE	Lack of capacity for Fonterra & HDI.	Lack of capacity in 11 kV network to supply Fonterra and HDI. Provide a solution as part of Transpower's Lower Waitaki Project a.s.a.p.
Timaru Area—Holistic	Lack of capacity in 220/110 kV interconnectors for ABY, TIM, TKA, and TMK. From time to time have to back up STU and BPD.	Request Transpower upgrade its 220/110 kV interconnecting transformers.
TIM GXP Supply Security	N-1 security returned.	
Highfield (TIM2952) feeder loading	Moderate to Heavily loaded feeder.	Long term establish West End zone substation off 33 kV TIM GXP (timing uncertain) or interim move some load onto Redruth 1 feeder ex NST substation.
Morgans Rd feeder (TIM2702) loading	Moderate to Heavily loaded feeder.	Long term establish West End substation off 33 kV TIM GXP (timing uncertain). Interim OK as we created a fourth feeder with the new TIM 11 kV switchboard and split the load.

Constraint	Description	Intended remedy
Levels feeder (TIM2852) loading	Moderate to Heavily loaded feeder.	Long term establish West End zone substation off 33 kV TIM GXP (timing uncertain). Interim OK as we created a fourth feeder with the new TIM 11 kV switchboard and split the load.
Mountainview feeder (TIM2712) loading	Moderate to Heavily loaded feeder.	Long term establish West End zone substation off 33 kV TIM GXP (timing uncertain). Interim OK as we created a fourth feeder with the new TIM 11 kV switchboard and split the load.
Washdyke feeder loadings	Heavily loaded feeders.	Establish future 33 kV sub-trans cables to area along with RMUs to break into existing network or establish future 11 kV zone substation switchboard, connect and run at 11 kV. Ultimately establish Washdyke 33/11 zone substation off 33 kV TIM GXP (timing uncertain).
TIM Sub-transmission to CBD	Heavy cable loadings.	Research feasibility to install four 11 kV 0.5 Ohm reactors in GRM and HNT sub-transmission to NST to force load onto new North-TIM cables or ultimately establish city 33/11 zone substation off 33 kV TIM GXP (timing uncertain).
PAR 1 and 2, 33 kV line regulation	Voltage constraint over 7 MVA of load (6% volt drop).	Planned releases shift some load to TIM and STU (as required). Fault response depends on load, shift loads as possible, non-supply if situation arises. Tying live to STU first needs 110 kV system tied to get the 11 kV in phase. Alternatively, dead change overs are done. Rebuild sub-transmission in Iodine presently underway will take four years (requires new pole positions). Rebuild No 2 first as more aged. Establish new STA GXP for partial load transfer (2017/18).
PLP T1	At present suitable, large connection enquiries in Totara Valley area cannot be met. Any new transformer to be selectable between Dyn11 and Dzn0 to suit TIM 33 kV GXP vector group changes.	Larger transformer and heavy or dual feeder to Totara Valley, or new zone substation at Totara Valley for load transfer (timing uncertain).

Constraint	Description	Intended remedy
Temuka Area - Holistic	Lack of capacity for TMK 33 kV GXP load.	Work with Transpower on upgrading supply assets. Request Transpower upgrade its TIM 220/110 kV interconnecting transformers.
TMK GXP Supply Security	Load constraint over 60 MVA transformers, 70 MVA on lines, 71 MVA 33 kV switchboard.	Request Transpower upgrade its TIM 220/110 kV interconnecting transformers, or new investment in 110 kV line, 110/33 kV transformer and 33 kV switchboard upgrade.
RGA 33 kV sub-trans 1 line regulation	Voltage constraint over 8.4 MVA of load (6% volt drop).	Look to replace cable in Winchester and check conductor sags. Second 33 kV feeder to RGA took load in 2013. For a sub-trans tripping, shuffling of load is required, most can be done via remote control so quick response. Long term sub-trans review required.
GLD 33 kV sub-trans 1 line regulation	Voltage constraint over 8.64 MVA of load (6% volt drop).	Watch on GLD loading as RGA load is transferred. Load may be able to go back to RGA depending on final irrigation scheme load.
Otaio feeder regulation (STU) and St Andrews feeder regulation (PAR) Both to same area—feed from both ends	Voltage constraint at end of feeders.	New voltage regulator installed at Cup and Saucer and loaded with capacitors, feeder at end of capacity from both STU and PAR. Look to load up PAR's Holme Station feeder to offload PAR feed toward Otaio. Dairy Factory off loaded to Mt Studholme feeder. New feeders when second dryer established (timing unknown), or if dryer delayed put dairy on direct supply (0.7% volt rise at end of feeder). When St Andrews GXP built migrate feeders onto new GXP (timing unknown—? 2019).
Geraldine CBD (GLD)	Voltage constraint at end of feeders.	Install capacitor from 2014/15 plan, review required.
Waimate CBD (STU)	Voltage constraint at end of feeders.	Plan was to install capacitor in 2013/14 however, deferred as no locations were available in CBD.
Mt Studholme Feeder (STU)	Voltage constraint at end of feeders.	Existing Mt Studholme capacitor needs chokes on existing site to suit ripple 2014/15 plan.
STU ripple plant	Ripple signal attenuation will occur with Transpower's new	Procure new 11 kV cell when Transpower

Constraint	Description	Intended remedy
	transformers.	actions project.
Fairlie rural feeders (FLE)	Voltage constraint at end of feeder.	Many spurs into the rural areas are getting LV at far ends. Because of numerous locations one voltage regulator or capacitor cannot correct (capacitors have to wait for a change of ripple plant at ABY). Larger conductor uneconomic.

Table 5.12 Network capacity constraints

5.4.1 Non-electrical constraints

Our network is not only constrained electrically, but also by the environment within which it is constructed. Non-electrical constraints are discussed in this section.

5.4.1.1 Coastal environment constraints

Part of our network is built within a coastal marine environment, which is hostile to most components used in an electricity network and is the principal driver of accelerated maintenance programmes. Assets designed specifically for the coastal marine environment are used wherever possible. For more information please see Chapter 6—LIFE CYCLE ASSET MANAGEMENT PLANNING.

5.4.1.2 State highway constraints

Proposed changes by road control authorities to road corridor utility access have meant that some projects along state highways have not proceeded. New restrictions requiring poles to be a minimum distance from the road edge line, depending on traffic volumes and other criteria, would result in lines being constructed on private land with associated easement negotiations and costs.

With a large part of our backbone network built along the dominant state highway traffic routes, there is considerable risk of us failing to gain approval from the road control authorities to replace works at end of life. While replacing poles like-for-like can occur, conductor sizes often increase with the rebuild, requiring new pole positions to cater for changed span lengths. Shifting an overhead asset away from the highway (if private land owners' approval is gained) can cause significant additional risk and cost.

5.4.1.3 Available resourcing constraints

Resources remain a constraint on planned work. Demand growth in South Canterbury has focused efforts on capital investment in the construction of new network assets to meet consumer needs. Consequently, maintenance work has had to be carefully triaged with priority given to the most urgent work, while minor maintenance is deferred pending available resource.

5.4.1.4 Land access agreements and easement constraints

Access to private land is becoming more difficult where land owners may not receive direct benefit from the new works. There is now substantial cost and lead time associated with negotiating land access and electricity easement agreements, affecting the timing of new works.

5.4.1.5 Resource consents

The Timaru, Mackenzie, and Waimate district plans state that, for projects over $50 million, no new overhead line, or line voltage or conductor upgrade can commence in commercial or residential areas without resource consent. The consent approval process involves consultation with every land owner whom the line passes over or is in view of, contributing to additional cost and lead time.

5.5 Criteria to consider when planning

Planners must consider the following criteria when assessing the various options available to meet forecasted load[37].

5.5.1 Non-network options

Our aim is to continually improve the utilisation and availability of existing network assets. Technological solutions have been implemented to improve operating efficiency and include the installation of a SCADA system, microprocessor substation protection relays, line fault indicators, and a load management system. Decisions on asset replacement vs continued maintenance or refurbishments are subject to economic analysis to determine the most cost effective option; in some cases, this may result in a partial replacement of an asset. Assets removed from the network during upgrades are assessed for condition and, where possible, reused elsewhere on the network.

One area where we can leverage energy efficiency is non-network solutions, particularly demand side management. Consumers with sensitive loads have considered installing stand-by diesel generation to provide a non-interruptible supply. The distributed generation initiative is expected to be a more common approach in future network planning. However, a cautionary point to consider is the UK standard P2/6 prohibition against using distributed generation to contribute to security of supply.

The high level risk of single transformers at zone substations has been identified in the risk management section of the AMP. The cost of purchasing a second transformer against the need for managing the planned loss of supply (LOS) for two to five-yearly Transpower maintenance at ABY and TKA GXPs has influenced plans for one national mobile substation (110/33 kV or 22/11 kV) for Transpower. We have built one 33/11 kV mobile substation that can double as an emergency back-up for faults and as a temporary second transformer for avoiding planned outages when maintaining single transformers.

[37] The criteria in section 5.5 will better complement our asset management strategy when we fully implement the Network Development Plan (NDP) prioritisation process discussed in Section 5.10—Continuous Enhancement.

Other risk treatment supports the use of distributed generation as a limited back-up supply to mitigate single transformer failure or to allow work on a mid-section of overhead line while keeping the far end live. We now have two 500 kW portable generators for emergency stand-by or voltage support duty. Our portable generators can run separate at 400 V, ganged at 400 V, or stepped up to 11 kV, helping maintain service expectations of our consumers. Our 190 kW portable generator has proved invaluable for small projects. We have also hired sets of generators for larger multi MW projects.

5.5.2 Demand side management

Demand side management consists of contracting with consumers that have electric hot water storage units to place load on a controlled rate tariff, allowing load interruption at peak times. The ability to interrupt load lowers the peak demand on the network and the transmission grid. Retailer pricing, in some cases, has eroded the price signal between controlled and uncontrolled rates, tempting consumers not to abide by the network policy of hot water storage heating control. A clearer pricing signal has been provided by us independent of retailer pricing, restoring the use of controlled hot water heating.

Further work will be required to consider demand side management for interruptible consumer load. Irrigation is an area, like electric hot water storage heating, that potentially could have supply interrupted during peak demand periods, while still meeting the consumer's irrigation expectations during times when control is not exercised. A special tariff would need to be developed to provide irrigators with a price signal, incentivising the placement of load under control during peak times when load curtailment is required.

Irrigation load control would need to be discussed with the industry as irrigation systems are now quite complex and sophisticated, with computers controlling the rate of spray irrigation against the soil type and moisture content, as well as the evapotranspiration rates at the time of water application.

During the transmission constraints into the Zone 3 area over the past two years, we have contacted large consumers with refrigeration loads to discuss demand side management opportunities. Discussions were commenced on a voluntary public good basis and would need to be developed into a commercially viable proposition, providing appropriate incentives for regular load shifting possibilities.

5.5.3 Options to meet security

A key component of security is the level of redundancy that enables supply to be restored while a faulty component is repaired or replaced (the spare tyre philosophy). Typical approaches to providing security at a zone substation include the following.

- Provision of an alternative sub-transmission circuit into the substation, preferably separated from the principal supply by a 33 kV bus-tie.
- Provision of twin transformers with emergency rating, allowing one to cover the load of the other if it trips or faults.

- Provision of back-feed on the 11 kV from adjacent substations where sufficient 11 kV capacity and interconnection exists.[38]
- Use of local generation (Opuha Dam) or portable diesel generator set(s).
- Use of interruptible load (e.g. water heating or irrigation) to reduce overall load.

The difficulty with security is that it involves a level of investment beyond that needed to meet demand, and it can be easy to let demand growth erode security headroom.

5.5.3.1 Prevailing security standards

The commonly adapted security standard in New Zealand is the EEA Guide for Security of Supply, which was revised and reissued in August 2013 and reflects the UK standard P2/6.

P2/6 is a revision of the earlier P2/5 that was developed by the Chief Engineers' Council in the late 1970s. P2/5 was a strictly deterministic standard as it stated which amount of load would have what level of security, with no consideration for individual circumstances.

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

5.5.3.2 Issues with deterministic standards

A key characteristic of deterministic standards, such as P2/5 and the earlier EEA Guide is that rigid adherence generally results in at least some degree of over-investment. Accordingly, the new revised EEA Guide for Security of Supply recommends that individual circumstances be considered.

5.5.3.3 Contribution of local generation to security

To be of use from a security perspective, local generation (hydro, wind, or solar in our case) would need to be 100% available—unlikely from a reliability and primary energy perspective. It is for this reason that P2/6 provides for minimal contribution of such generation to security.

5.5.3.4 Existing security standards

Existing levels of security at GXP and zone substation level can be found in the AMP—Major Assets.

5.5.4 Issues arising from estimated demand

Description of significant issues arising from demand forecasts discussed in the section can be found in the AMP—Major Assets.

[38] Such an arrangement requires that, firstly, the adjacent substations are restricted to less than nominal rating and, secondly, that the prevailing topography enables interconnection.

5.5.4.1 Transpower and GXP new investment estimates

The expansion of GXP capacity can be funded either by us or Transpower. At this stage, it is anticipated that Transpower will fund GXP investment and the cost will be passed through to the consumer as part of the transmission charge, and treated by us a pass-through cost under the default price-quality path. The expected investment at each GXP is shown on a per project basis. The actual charges to consumers will be subject to the term of investment agreement and the cost of capital payments required by Transpower.

5.5.5 Estimated asset utilisation

In contrast to the general emerging trend, we expect asset utilisation to increase in the dairy and irrigation areas as kWh throughput grows faster than maximum demand. Although encouraging asset utilisation, the flat and constant load profile of irrigation at elevated ambient temperatures during seasons of drought provides no thermal relaxation to the distribution assets. Another challenge is arranging access to the assets without interrupting dairy irrigation and milking cycles.

5.5.6 Impact of climate change on planning

In 2013, we experienced weather events that had not been seen in over 30 years and included flooding, wind and snow storms. A recent report from the Prime Minister’s Science Advisory Committee on the localised impacted of climate change stated that we should expect more frequent flooding events, stronger and more frequent north-west winds, and more snow at higher altitudes. We should also experience less rainfall overall.

In 2014, the Intergovernmental Panel on Climate Change (IPCC) issued its Fifth Assessment Report—Climate Change 2014. In regarded to New Zealand, it stated the following.[39]

- ‘New Zealand’s predominantly hydroelectric power generation is vulnerable to precipitation vulnerability. Increasing winter precipitation and snow melt, and a shift from snowfall to rainfall will reduce this vulnerability (*medium confidence*) as winter/spring inflows to hydro lakes are projected to increase by 5 to 10% over the next few decades. Further deductions in seasonal snow and glacial melt as glaciers diminish, however, would compromise this benefit.’
- ‘Increasing wind power generation would benefit from projected increases in mean westerly winds, but face increased risk of damages and shutdowns during extreme wind.’
- ‘Climate warming would reduce annual average peak electricity demands by 1 to 2% per degree Celsius across New Zealand.’
- ‘In New Zealand, increasing high winds and temperatures have been identified qualitatively as the most relevant risk to transmission.’

[39] Reference: IPCC’s website at: www.ipcc.ch/report/ar5/wg2/

5.5.7 Equipment used in capital expenditure

Using a set of parameters helps standardise the design and equipment use in capital expenditure, leading to cost efficiencies. We use the following criteria when determining the equipment required to meet load growth/capacity requirements (for more information please see Appendix E—SELECTION OF EQUIPMENT).

5.5.7.1 Reliability and security of supply

Security standards that may be adopted by is follow the issue of the revised EEA Guidelines for Security of Supply in New Zealand Electricity Networks, meaning that, on the sub-transmission system, we will strive to achieve an N-1 security level[40].

It is difficult to set a MW level or ICP number at which N-1 security is required due to the diversity of consumer loads and requirements, as well as the significant variance in load levels. Each case is evaluated on its merits and the criteria used for evaluation include: the importance of supply to Timaru CBD, milk processing plants, dairy farms, tourism destinations, meat works, irrigation concerns; and where LOS could have significant economic and possible environmental consequences.

Our network does not currently conform to the security of supply standards. It is the intention of this plan to achieve the security of supply standard referred to above within the 10 year planning period covered by this plan. Existing security levels are listed in the AMP—Major Assets.

5.5.7.2 Voltage regulation

Electricity regulations require us to control voltage within ±6% of the declared potential, except for momentary fluctuations (voltage dips). In order to comply, we take care to select the appropriate capacity when choosing equipment that may influence voltage regulation. Equipment with influence on voltage control includes: power transformers fitted with On Load Tap Changers (OLTCs), voltage regulators, capacitor banks, distribution transformers fitted with Off Circuit Tap Changers (OCTCs) switches, cables and overhead conductors.

5.5.7.3 Harmonics

Voltage and current harmonics are becoming more important with the large number of variable speed drives (VSDs) being installed on our network (specifically to drive irrigation pump motors). Since harmonics generated by one consumer can adversely affect the supply to others, consumers are required to comply with:

i) the New Zealand Electrical Code of Practice for Harmonic Levels, NZECP 36:1993, and

ii) our harmonic standard[41] that was developed with the assistance of other electricity distribution businesses.

[40] N-1 security implies that the loss of a single element would not result in the interruption of supply.
[41] This standard is an extension of NZECP 36 and provides more detail to enable consumers and suppliers of VSDs to design filters for limiting the harmonics injected into the network.

Our harmonic standard is an extension of NZECP 36 and provides detail which enables consumers and suppliers of VSDs to design filters to limit the harmonics injected into the network.

5.5.7.4 Faults

We had some of the highest 11 kV fault levels in New Zealand at the TIM substation. This is a critical factor in the design and specification of network equipment such as switchboards, cable and cable screen ratings, surge arresters, ring main units, overhead line drop-out fuses (Dos), and so on. In addition, all new switchboards are installed with arc flash protection schemes.

We worked in partnership with Transpower to reduce the TIM fault levels. For example, earth faults we reduced when NERs were installed in 2012; phase fault levels were lowered when the three new supply transformers began operating in 2014 with two in service and one on stand-by. Other substations will be cared for as they are upgraded with large supply transformers.

5.5.7.5 Power factor

The closer the power factor is to 1, the more optimally the infrastructure is utilised. We are achieving this through our new connections policy and technical requirements, which applies to all new plant connecting to the network. A combination of voltage regulators and capacitor banks is used on the network to improve voltage along loaded feeders, the capacitors giving added benefit by compensating for reactive power losses or, alternatively, improving network power factor. The sizing of capacitor banks is important since overcompensation can lead to HV during light loading conditions where potential rise is seen to be an issue. Adjacent voltage regulators are used to lower potential.

5.6 Network development plan

This section describes the network development plan for each major network asset class. Capex project planned for the next 12 months can be found in Appendix B whereas Capex projects planned for the next 10 years can be found in Appendix C.

5.6.1 GXPs, zone substations, and sub-transmission

Detailed information on GXP, zone substation, and sub-transmission assets can be found in the AMP—Major Assets. For development project, both planned and underway, please refer to Appendix C.

5.6.2 Voltage support

Section 5.6.2 describes network plans for voltage support.

5.6.2.1 Voltage regulators

Voltage regulators have become increasingly important in providing potential support in lengthy light conductor 11 kV distribution lines. Most lines were built in an era of dry farming however, with the rise of dairying and irrigation the loads have exceeded the original design parameters of the lines. It is very costly to reconductor line as new poles at shorter span lengths are often required. Rebuilding can be complex when lines pass down state highways as all new builds have to be 9 metres from the road edge. If the lines pass over private land, negotiations for easements are required.

Since 2008, a number of voltage regulators have been installed and new installations are carried out on an as required basis. The exact requirements are difficult to determine until loads are known, as the requirements are dependent on the location of load growth. Therefore, an annual fund is required for suitable voltage regulator installations to match the growing load.

5.6.2.2 Shunt capacitors

The addition of shunt capacitors to lines is another useful method to provide potential support and avoid the expense of reconductoring. Often shunt capacitors can be installed in conjunction with regulators to provide a hybrid solution.

Although all new loads are requested to be power factor corrected (i.e. 0.95 lag or higher), this is often not the case. However, capacitors provide high level correction, minimising losses due to reactive power supply. Capacitors are passive devices so require minimal maintenance, whereas regulators are on a quadrennial inspection and maintenance cycle. Capacitors are generally more economical to install than regulators and can be connected via a simple ABS and set of DOs.

Capacitors do present voltage rise problems when the network is lightly loaded, so careful planning and design is required to ensure that the they do not raise the potential outside the regulated limits throughout the load cycle. Some network operators switch strategic capacitors out during low load periods.

Some networks have notes capacitors to attenuate ripple control systems. We have standardised our 317 Hz ripple with the view that this frequency was low enough not to be affected by capacitors. However, at least one site needs blocking chokes added and two more sites are under review. The older 500 Hz systems at ABY and TEK are more likely to have signal attenuated.

Capacitors are in high demand globally; they need to be procured six to eight months in advance, so do not suit AMP cycles coupled with the random load growth. We are of the view that, while load growth is prevalent, sufficient new sets of 1 Mvar and 0.5 Mar need to be procured and stored for the dairy off-season each year in readiness for the work programme of the next few years. A few capacitors on poles are currently out of service and chokes are need for repair.

5.6.3 Line reclosers

Our network has two 'ball and chain' reclosers that are at end of life and will be replaced by winter of 2016. Some more modern recloser types have not been as reliable as expected—consideration is being given to their future. Inclusion of more 11 kV line reclosers on the network allows greater segregation of feeders during faults, leading to a reduction in SAIDI.

Research will determine which feeders have the highest fault incidence, ensuring the best application of reclosers.

5.6.4 Distribution lines

New feeder cable details are established on a case-by-case basis. Generally, 300 and 400 mm^2 Al 3C heavy screen cable is used. Single core 400 mm^2 Al heavy screen cable was introduced as the lead out cable from switchgear during the TIM November 2009 fault repairs to limit further fault damage due to interphase faults in cable boxes. Transition joints were required in the ground—this arrangement seems to be a robust system to adopt as standard to minimise risk within switchgear cable boxes.

We are proposing to install a new feeder in GLD to split the CBD load, most likely cabled. Meanwhile, various undergrounding projects are being carried out in the various districts on our network—some projects include 11 kV assets.

5.6.5 Protection, control, and measurement

We have a mix of protection assets installed. Some substations have had microprocessor equipment like SEL and MiCom installed that have an expected service life of 20 years. There is a range of static protection like ABB Combiflex and SPACOM that also have a 20 year expected service life. The replacement of some protection assets is occurring naturally; for example, Combiflex has recently been removed from PLP and PAR substations. Further planning is required to replace the remaining assets.

There is a range of electromechanical equipment from MetroVickers, AEI, GEC, and Reyrolle. Provided the relays are well maintained, they normally have a similar life to that of the switchgear in which it is installed (40 years). As switchgear is upgraded and protection replaced, some relays may be brought forward.

As more advanced systems of sub-transmission are installed, faster types of protection will be required. If a meshed 33 kV overhead sub-transmission system is installed, distance and/or differential protection with signalling will be required. Both have communication requirements—either fibre optic or reasonably fast and dependable radio.

For smaller substations with lower fault levels, there has been a trend away from traditional bus bar protection. At BPD and RGA, an under-impedance relay is being installed on the HV side of the transformer. The relay will be set to detect LV bus bar faults and provide clearance in 0.5 seconds—approximately the same time delay as the fast bus blocking schemes adopted in more recent times. It is a simpler scheme that should reduce the number of human incidences that seem to accompany complex bus bar protection schemes.

For substations with higher fault levels, traditional dual zone (measure and check) bus bar protection should be installed as per CD1 and CD2 (2004 era). We adopted CD1 and CD2 when we upgraded NST and GRM. Arc flash detection (AFD) equipment has been installed on recent switchgear at RGA, NST, and GRM to work in combination with the current check to clear arcing faults within the switchboard. We are presently retrofitting AFD at HNT as a pseudo bus bar protection.

We have two substations with fast bus blocking schemes—STU and TMK.

5.6.5.1 Control

By introducing centralised control we have complemented the manual control of zone substation equipment by our field operators. A general upgrade to some stations' control systems is being carried out. Some local manual control will always be desirable in order to maintain field operator competencies in preparation for emergencies and possible communications outages. A pole top automation programme to enable easy remote control of reclosers has commenced.

5.6.5.2 Measurement

As with the protection relays, different methods of measurement are taken at substations—modern microprocessor relays allow direct measurement, while older stations may have transducers.

5.6.5.3 Communications

We have a mix of communications:

- Tait VHF and two bit alarm systems.
- Tait 300 UHF radio connecting Conitel RTUs, and Leeds and Northup RTU50 DCIU
- Tait 300 UHF and digital radio connecting Abbey RTUs to ripple plant
- Fibre optic cable routed and switched to SEL communication processes to connect directly to SEL relays
- Digital UHF radio routed and switched to SEL communication processes to connect directly to SEL and MiCom relays.

We are working on retiring the Tait VHF and 300 UHF analogue radio networks for network control. Fibre and digital radio are the preferred options.

5.7 Material capital expenditure projects

This section describes and justifies our material Capex (i.e. all Capex projects with a total spend of over $300,000) works plan for the next 12 months.

For discussion on how our target levels of security will be affected, please see Section 4.4.5—Ten-year reliability target. All Capex planned for the next 12 months, both material and immaterial, can be found in Appendix B.

The justification and decision made to satisfy service levels, as well as alternative options considered (including non-network solutions), are detailed in the following sub-sections.

5.7.1 Project name: Timaru to Washdyke 33 kV cables

This project comprises the installation of four new cable circuits from the Timaru GXP to the centre of the Washdyke industrial area. The project cost will be $4.2 million.

Justification

The Washdyke area load now exceeds 12 MW at peak times, and the area is still expanding rapidly. The existing circuits supplying the are now inadequate as only small portions of any one feeder's load can be transferred to others in case of a cable fault. Based on a 48 hour fault finding and cable repair time, an outage due to a cable fault could result in a value of loast load (VoLL) of up to $7 million.

Alternative options/non-network solutions

We have also considered diesel generation for periods of high demand but, due to the magnitude and non-cyclical nature of the demand, predicting peak is difficult, making this type of supply expensive.

5.7.2 Project name: New subdivisions and extensions

New connections, subdivisions, and extensions make up 13% of our Capex budget. This portion of the budget is based on recent expenditure to realise new connections and extensions, and is mainly driven by irrigation supplies and dairy conversions. Most of the costs of this work are recovered from customers and developers.

Justification

Electricity demand growth and new connection applications.

Alternative options/non-network solutions

An alternative option would be to refuse connecting additional load but this will only happen if there is no spare capacity on the network. The lack of capacity, however, would initiate a network upgrade (if one had not already been planned).

5.7.3 Project name: Ring main unit replacement

We have embarked on a programme to systematically replace all RMUs of the Andelect type, as well as the oil filled RMUs. In some cases, these RMUs are located in underground substations and are difficult and expensive to relocate. The cost associated with this project is $300,000.

Justification

The Andelect type RMUs have a history of failures and are being systematically replaced by the industry as a whole. The health and safety concerns around these switches are the main cause for the replacement programme. We are also looking to replace most of the oil filled RMUs. Health and safety, age, and condition are the main drivers. When oil filled equipment fails, a fire is a possibility resulting in severe consequences from a risk assessment perspective.

Alternative options/non-network solutions

As part of evaluating alternatives, we are currently investigating RMUs with solid insulation. The large size of this type of equipment makes change-outs more costly and complicated. Getting rid of the oil switches without replacing them is not an option. The RMU switches allow the network to be configured and operated in a manner that maximises supply reliability; we would not be able to meet our regulatory quality obligations without them.

5.7.4 Project name: Underground cable upgrades

These projects include both growth and replacement work. We have embarked on a programme to upgrade and replace all the LV Lucy type link boxes on our network. The expenditure on these projects totals $600,000

Justification

The Lucy boxes on our network have had increasing problems in recent years. Overheating of connections can lead to damage of the links, restricting access to neighbouring connections. The restricted access is problematic as it reduces the ability to offload these boxes to other parts of the network. This inflexibility is an issue as the boxes are an integral part of the LV reticulation that supplies shops and other businesses in the Timaru CBD.

The replacement of these boxes also allows us the opportunity to make provision for the connection of stand-by generation, permitting access to other parts of the network for planned maintenance without disruption to supply. The replacement of link boxes would allow the off-loading of underground substation circuits, which is difficult to achieve at present.

Alternative options/non-network solutions

Due to the health and safety risk around this specific type of link box, we have no alternative but to replace it. A failure to do so could result in extensive damage and reduced reliability of supply.

5.7.5 Project name: Overhead to underground conversions

The aim of these projects is to remove existing overhead lines from private land. The cost of the projects planned is $430,000.

Justification

Access to these overhead lines for maintenance and during network emergencies is difficult, translating into increased outage times and reduced reliability. The undergrounding will eliminate the risks associated with overhead lines across private land as, in a number of cases, these lines traverse dwellings.

Alternative options/non-network solutions

There are no alternative options. Relocating existing lines is not permitted under the current Timaru District Plan.

5.7.6 Project name: Bells Pond supply security upgrade

This project comprises the installation of a second supply transformer at our Bells Pond GXP. Due to the scale of the project and the lead time for large power transformers, the project will span two financial years. Preparatory site work will take place in 2016/17 at a cost of $1.5 million. The bulk of the expenditure will be in the 2017/18 financial year, when transformer and switchgear are delivered.

Justification

The supply demand on this substation has grown from just over 5 MW in 2010 to more than 10 MW in 2015 with confirmed demand growth due to the Waihao Downs irrigation scheme and the Oceania Dairy factory of more than 4 MW by the end of 2016.

Using our Risk Management Policy to evaluate the impact of the loss of the current supply transformer (low probability but severe consequence), the risk scores for 'Reputation, Asset utilisation, and Security' were all of 'medium' severity. The risk score for 'Reliability' was determined to be of 'high' severity which requires an action plan within a specified timeframe.

In addition, a calculation of the value of lost load (VoLL) based on the EEA *Guideline for the Security of Supply* resulted in a VoLL of $2.72 million for a short duration outage, and $69.88 million for a long duration outage to replace the faulty transformer.

Alternative options/non-network solutions

Due to the magnitude of the load required (i.e. 3 MW to keep the dairy factory going) and the load curve (sustained supply requirement), diesel generation is not economical or practical due to the space constraints and the remote location of the site.

In addition, the dairy factory is currently in a planning phase for the second dryer which could add another 3 to 4 MW to the current load demand, making alternative solutions less feasible.

5.7.7 Explanation of material variance

This section deals with the differences between the 2015/16 AMP Capex budget totals and the 2016/17 AMP Capex budget totals. For the purpose of comparing the AMP budgets only the overlapping nine years from 2016/17 to 2024/25 are considered.

For the period 2016/17 to 2024/25, the overall budget has increased from $80.85 million to $111.32 million. Table 5.13 below lists the material projects that have contributed to this increase.

Index	Project	Budget (million)	Timeframe
a)	New Waihao Downs GXP (WDN)	$ 5.7	2017–20
b)	Cable upgrade to Washdyke	$ 4.2	2016
c)	Second transformer at Bells Pond (BPD)	$ 4.5	2016–18
d)	Double circuit 110 kV from WDN to BPD	$ 4.45	2017–19
e)	General overhead line refurbishment	$ 14.2	2016–26

Table 5.13 Projects creating material variance

Waihao Downs GXP

This project is the result of Transpower's transmission grid operating at capacity with respect to the supply to Studholme and Bells Pond. These two GXPs constitute the main supply to the Fonterra milk factory at Studholme, the Oceania Dairy milk factory near Glenavy, and the Waihao Downs irrigation scheme. The new GXP would also be required to supply the Hunter Downs irrigation scheme if/when it goes ahead.

Fonterra is currently in the process of obtaining resource consent for building an additional two dryers at the Studholme plant. Oceania Dairy has just started the construction of a UHT and canning plant at their factory while planning is underway for a second dryer. The projected load growth related to these projects necessitates the construction of a new GXP, as well as overhead line (a combination of a) and d) in Table 5.13.

Transformer at Bells Pond GXP

Load growth at the Bells Pond GXP has now resulted in a 10 MW maximum demand at this substation, which will increase to 14 MW by the end of 2016 as a result of the Waihao Downs irrigation scheme load, as well as the Oceania Dairy developments currently underway. Base on the EEA's *Guide for Security of Supply*, this level of load justifies the need for a secure supply. To provide this security, a second transformer and a new swtitchroom is required at the Bells Pond GXP.

Washdyke cable upgrade

The developments in the Washdyke industrial area have resulted in our inability to fully offload any of the four feeders currently supplying this area onto adjacent feeders in case we lose any one feeder. This restriction necessitates an upgrade to the supply to this area. Due to the developments in the area, the only practical solution is a cable upgrade from the Timaru GXP to Washdyke (a combination of b) and c) in Table 5.13).

Overhead line refurbishment

Based on the last few years' expenditure on overhead and line renewal and refurbishment, it is apparent that the previously projected expenditure of $1.2 million for the latter 7 year period of the 10 year planning period is inadequate. This figure, therefore, has been increased to an average of $3 million per annum to better reflect expected costs.

Our expenditure on asset replacement and renewal projects is some 20% below the industry median[42]. In addition, 50% of our overhead line (pole) network is between 40 and 60 years old (i.e. approaching end of life), necessitating increased expenditure in this area.

5.8 Material non-network capital expenditure

This section describes material non-network Capex projects. Material projects are those with a cost of over $300,000. Our 10 year non-network expenditure can be found in Table *1.3*. There is no material non-network Opex.

5.8.1 Smart meters

A roll out of smart meters will continue till 2016/17 when spending will curtail from $7.5 million per annum to around $68,000 in 2017/18. It is forecast to remain at this rate.

5.8.2 Information technology

We have recognised the need to develop our information management technology and are investing a total of $3.6 million in this area over the next three years. This investment includes the determination of business requirements for our asset management and finance departments, as well as the upgrading, replacement, or development of software fit for purpose. Note that our expenditure forecasts do not capitalise labour expenses.

Projects presently being worked on are listed below.

5.8.2.1 Axos

We are in the final stages of implementing our new cloud-based billing system, Axos. The new system is flexible and will allow us to offer new pricing models, as well as enable us to adapt quickly as solar and other technologies grow on our network.

5.8.2.2 GIS

Our ICT team is developing software and processes to provide:

- one source of truth for geospatial information on assets
- a fit-for-purpose and fit-for-use facility to identify assets to ensure compliance with the Electrical (Safety) Regulations 2010, clause 46(1): 'The owner of works must keep such records and plans of those works as will enable the owner, if required, to readily locate any fittings of the works.'
- information for operational purposes—both business as usual (BAU) and emergency use (not including switch or isolation statuses)
- easy reporting on asset types for maintenance purposes
- asset details with connections or proposed asset management system to allow New Connections to design and plan new extensions

[42] PriceWaterhouseCoopers Electricity Line Business 2015 Information Disclosure Compendium, November 2015.

- a single source of truth with asset management system for all asset data for load flow modelling (using Powerstation ETAP)
- a compatible interface with other enterprise solution such as SCADA (Survalent), ICP database, asset management, etc.

We have now acquired industry standard software (ESRI GIS system) to replace our legacy GIS system. The new system has better functionality, additional features, and is well supported by its industry leading supplier. The new GIS system will also be compatible with our new asset management system.

5.8.2.3 Asset Management System and new financial package

We have contracted Technology One for our new Asset Management System. The implementation phase has a ‘go live’ date of 30 October 2016.

The Asset Management System is part of Enterprise Resource Planning (ERP) software called OneEnergy. The ERP includes a new financial package (also from Technology One) that will be fully integrated with and includes other important corporate functions that replace the present legacy financial systems.

5.8.2.4 SharePoint

SharePoint is now in use and has received positive reviews from staff. The aim of SharePoint is to:

- improve access to, and sharing of, knowledge and information, both within the organisation and externally with its partners
- automate and streamline processes to collect and process data and information with minimum effort to support lean working, i.e. maintain information in digital format rather than paper-based manual processes
- deploy interactive intranet
- deploy good collaboration tools to encourage participation and harvesting of new ideas.

5.8.2.5 Future goals

Our future ICT goals include:

- standard platform for development and interfacing with other applications
- reliable vendor support
- retiring or replacing existing applications
- documents and records management for single source of truth
- enterprise reporting platform that allows easy reporting by empowered end-users
- process automation.

5.9 Capability to deliver

We believe that the plans and objectives discussed in this AMP are realistic and achievable.

As a small company that works in close proximity (physically and culturally) to our preferred contractor, NETcon Limited, we benefit from an open-door approach to network planning. As part of our daily activities, planners and contractors meet face to face to identify efficiencies, resources, and solutions to constraints to ensure projects proceed as planned.

In November each year planning sessions are held with NETcon to determine the following year's work programme. During the planning sessions, budgets and responsibilities are determined, resources and constraints identified, the approach to risk management discussed, and the timings of the project confirmed.

To ensure that we can deliver on the current year's work programmes, we meet fortnightly to discuss such topics as resourcing, timing, and expectations. Meeting minutes are held by our General Manager—Network.

Our informal approach to the relationship with NETcon has served us well in the past in supporting our asset management planning and decision making. However, we now have an Alliance Agreement with NETcon, helping us enhance asset management systems and processed.

We are also strengthening our planning with the introduction of a risk matrix that will factor in risks across the project including health and safety, financial, and asset-related risks.

5.10 Continuous enhancement

5.10.1 Load forecasting

The aim of load forecasting is to assist in the planning of network development that meets the demands of our stakeholders for safe, efficient, reliable, and cost effective energy delivery. Of importance is the need for targeted expenditure so as not to overinvest in the network.

In order to meet stakeholder demands, we are continually enhancing our planning process. At present network development includes:

- an industry liaison team
- implementation of the network development plan prioritisation process.

5.10.1.1 Industry Liaison Team

The aim of the Industry Liaison Team is to further develop relationships with our key energy consumers to confirm their future energy requirements and to inform them of our information needs concerning build times, etc.

An area that causes us concern is the lack of notice given by consumers to allow us to develop assets for their use, making forward planning uncertain. That is, often consumers will not release their plans to us until late in the process (possibly because of commercial sensitivity), leaving us little time to develop the network to their requirements.

5.10.2 Network Development Plan prioritisation process

The Network Development Plan (NDP) prioritisation tool is a new process that balances our requirements for plant performance, risk management, and financial performance. The prioritisation process is shown in Figure 5.8.

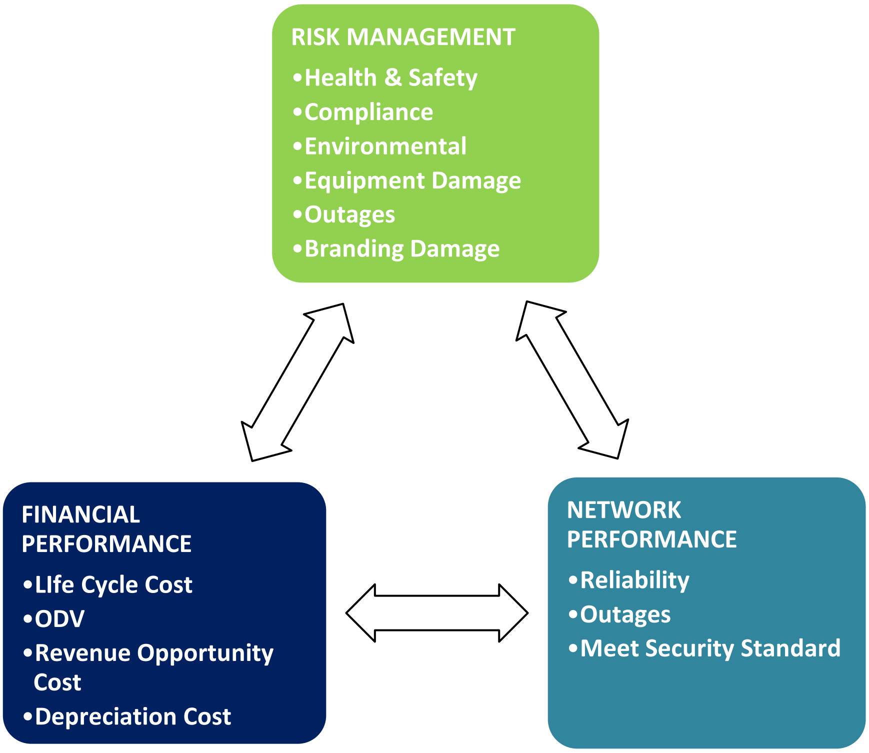

Figure 5.8 Balancing performance driver requirements

A key enabler for the NDP process is the risk-based analytic hierarchical process (AHP). The AHP will prioritise projects based on the level of risk to:

- health and safety
- reputation
- finance
- the environment
- compliance.

Risk to each is assessed and projects investigated to reduce the level of risk to acceptable levels. Projects are ranked in order of priority depending on several criteria using the AHP with support from ISO 31000, to add weighting to each criterion.

To ensure a structured decision making process, the AHP is applied to all of our Capex projects. Table 5.14 describes the areas of planning for which criteria are developed.

Criteria	Description
Risk reduction	health and safety reputation environmental compliance financial impact
Reliability of supply	SAIDI (unplanned) SAIFI (unplanned)
Security of supply	
Project implementation	cost ease of implementation SAIDI (planned)

Table 5.14 Risk assessment criteria for planning

6. LIFE CYCLE ASSET MANAGEMENT PLANNING

6.1 Introduction

Chapter 6 describes how assets are managed over the entire life cycle, from construction to retirement.

6.2 Maintenance planning

We manage our assets through the objectives set in our Statement of Corporate Intent (SCI) to provide a safe, efficient, reliable, and cost effective energy delivery system.

6.2.1 Linking strategic objectives to life cycle management

The main planning criteria and assumptions for the life cycle management of our network assets are:

- safety of public and employees
- statutory and regulatory requirements
- design
- economic efficiency
- cost benefits
- condition assessment of plant through its life
- service level and service target of plant
- operational procedures
- type and size of plant
- loading and relative importance of plant
- supplier's/manufacturer's recommendations for equipment
- maintenance pegged to industry best practices and evolution of same
- field experience with operation and maintenance of the plant on the network
- age of plant.

Table 6.1 illustrates the linkages between the objectives of our SCI and the planning criteria assumptions.

Criteria	Safe	Efficient	Reliable	Cost effective
Safety of public and employees	X			
Statutory and regulatory requirements	X	X	X	X
Design	X	X	X	X
Economic efficiency		X		X
Cost benefits				X
Condition assessment	X	X	X	X
Service level	X	X	X	X
Operational procedures	X	X	X	X
Plant type and size	X	X	X	X
Loading and importance		X	X	X
Suppliers’ recommendations	X	X	X	X
Maintenance to industry best practice	X	X	X	X
Field experience	X	X	X	X
Age	X	X	X	X

Table 6.1 Linkage between SCI and planning criteria and assumptions

6.3 Understanding asset life cycles

The life cycle of existing assets is outlined in Figure 6.1 and is defined in subsequent sections.

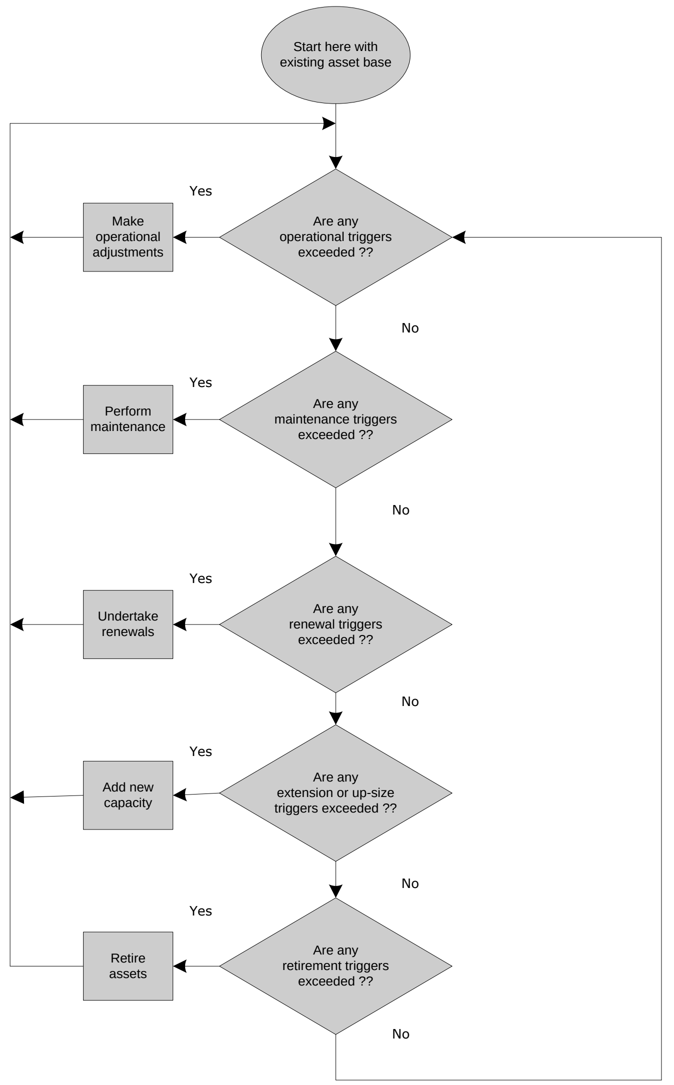

Figure 6.1 Asset life cycle

Table 6.2 provides definitions of our key life cycle activities.

Information Disclosure categories	Activity	Detailed definition
Routine and corrective maintenance and inspection	Operations	Involves altering the designed operating parameters or state of an asset such as closing a switch or altering a voltage setting. Does not involve any physical or functional configuration change to the asset—simply a change to the asset's operating state as defined or allowed by its design configuration.
	Maintenance	Involves replacing consumable components like: pole hardware, the oil in a transformer, or the contacts in a circuit breaker. Generally these components will wear out before the main asset

Information Disclosure categories	Activity	Detailed definition
		replacement, e.g. a pole. There may be a significant asymmetry associated with consumables such as lubricants in that replacing a lubricant may not significantly extend the life of an asset, but not replacing a lubricant could significantly shorten the asset's life. Lack of maintenance can also reduce the efficiency or operability of the asset and in some cases compromise safety. Vegetation management, including tree cutting, is included in maintenance.
Asset replacement and renewal	Renewal and refurbishment	Generally involves replacing a non-consumable item like a pole, transformer or switch. Such replacement is generally regarded as a significant milestone in the life of the asset and may significantly extend the life of the asset. Renewal tends to dominate the Capex in low growth areas (Quadrant 1 of Figure 5.1) because assets will generally wear out before their capacity is exceeded. The most typical criteria for renewal are when the capitalised cost of operations and maintenance exceeds the cost of renewal. A key issue with renewal is technological advances that generally make it impossible to replace assets such as SCADA with equivalent functionality.
	Upgrading	Generally involves replacing a non-consumable item like a conductor, bus bar, or transformer with a similar item of greater capacity that does not increase the network footprint.
Capex	Extensions	Involves building a new asset where none previously existed because a location trigger has been exceeded e.g. building several spans of line to connect a new subdivision to an existing line. Notwithstanding any surplus capacity in upstream assets, extensions ultimately require up-sizing of upstream assets.
Asset disposals	Retirement	Generally involves removing an asset from service and disposing of it. Typical guidelines for retirement are when an asset is no longer required, creates an unacceptable risk exposure or when its costs exceed its revenue.

Table 6.2 Definition of life cycle activities

6.3.1 Operating the assets

As shown in Table 6.2, Operations does not involve making physical or functional changes to network assets. Operations' role is to control the connectivity states of the network through switching and operating asset controls so as to allow electricity to flow from GXPs to consumers' premises. We operate a dedicated control room to intervene when an operational trigger point is exceeded and to carry out routine switching operations to allow access to the network and optimise connectivity.

Operational trigger points are set out in Table 6.3.

Asset class	Trigger event	Response to event	Approach
GXP	Voltage is too high or low on 33 kV or 11 kV	Automatic operation of tap changer to maintain voltage within limits	Proactive
	Demand exceeds allocated Transpower limit	Activate ripple injection plant to switch off load	Reactive
		Open and close 33 kV or 11 kV CBs to relieve load from GXP	Reactive
	Transition from day to night	Activate ripple injection plant to switch street lights on or off	Proactive
	On-set of off-peak tariff periods	Activate ripple injection plant to switch controlled loads on or off	Proactive
Zone substation transformers	Voltage is too high or low on 11 kV	Automatic operation of tap changer	Proactive
	Demand exceeds IEC 354 transformer rating	Open and close 11 kV CBs to relieve load from zone sub	Reactive
Zone substation CBs	Fault current exceeds threshold	Automatic operation of CB or recloser	Reactive
Zone substation CBs, distribution reclosers, and ABSs	Component current rating exceeded	Open and close CBs, reclosers and ABSs to shift load	Proactive or reactive
	Fault has occurred	Open and close CBs, reclosers and ABSs to restore supply	Reactive
Distribution transformers	Voltage is too high or low on LV	Shift load or manually off-line raise or lower tap where fitted	Reactive
	Fuses keep blowing due to high load	Shift load to other transformers by moving LV link box open points	Reactive
LV distribution	Voltage is too low at consumers' board	Supply from another transformer or LV circuit, if possible, by moving LV link box open points	Reactive

Table 6.3 Operational triggers by asset class

Table 6.4 outlines key operational triggers for each asset category.

Asset category	Voltage trigger	Demand trigger	Temperature trigger[43]
LV lines and cables	Voltage routinely drops too low to maintain at least 0.94 pu at consumers' point of supply. Voltage routinely rises too high to maintain no more than 1.06 pu at consumers' point of supply.	Consumers' pole or pillar fuse blows repeatedly. Load imbalance. Consumer complaint.	Infra-red survey reveals hot joint. Conductor sag diminishes ground clearances. Heating of grouped cables requires excessive de-rating.
Distribution substations	Voltage routinely drops too low to maintain at least 0.94 pu at consumers' switchboards. Voltage routinely rises too high to maintain no more than 1.06 pu at consumers' switchboards.	Load routinely exceeds rating where MDIs are fitted. LV fuse blows repeatedly. Short term loading exceeds guidelines in IEC 354. Harmonic load in excess of capacity. Consumer complaint.	Infra-red survey reveals hot connections. Transformer ambient temperature too hot, shortening life of transformer.
Distribution lines and cables	Voltage routinely drops too low to maintain at least 0.94 pu at consumers' switchboards. Voltage routinely rises too high to maintain no more than 1.06 pu at consumers' switchboards.	Consumers' pole or pillar fuse blows repeatedly. Load imbalance. Capacity of adjacent feeders insufficient to offload main feeder to retain supply following LOS to main feeder. Consumer complaint.	Infrared survey reveals hot joint. Conductor sag diminishes ground clearances. Heating of grouped cables requires excessive de-rating. Joint material migrates from termination.
Zone substations	Voltage drops below level at which OLTC can automatically raise taps. Load steps too coarse for	Load exceeds guidelines in IEC 354. Security guideline breached.	Top oil temperature exceeds manufacturers' recommendations. Core hot-spot

[43] Note that whilst temperature triggers will usually follow demand triggers, this may not always be the case. For example, an overhead conductor joint might get hot because it is loose or corroded rather than overloaded.

Asset category	Voltage trigger	Demand trigger	Temperature trigger[43]
	OLTC to react.	Consumer complaint.	temperature exceeds manufacturers' recommendations. Connections anneal and fail from thermal cycling.
Sub-transmission lines and cables	Voltage drops below level of line regulation to allow zone sub OLTC to correct.	No spare capacity to maintain security levels. Consumer complaint.	Infra-red survey reveals hot joint.
GXP equipment	Voltage drops below level at which OLTC can automatically raise taps.	No spare capacity to maintain security levels. Loading exceeds equipment rating.	Infra-red survey reveals hot joint.

Table 6.4 Operational triggers by asset category

6.3.2 Maintaining the assets and systemic failure identification

Asset maintenance includes regular inspection and condition monitoring, and repair and replacement of faulty or deteriorating components. Condition assessment provides for the detection and recording of gradual deterioration of components (as well as any systemic or type faults) and an opportunity for minor maintenance such as cleaning, maintaining protective coatings, and housing of assets.

Information gathered from inspections is analysed and corrective action is planned and executed as appropriate. Where necessary, maintenance strategies, plans, standards, and procedures are modified in line with conclusions from the analysis, particularly where systemic or asset type issues are revealed.

Electricity distribution network assets are installed outdoors, in buildings, or in outdoor enclosures and all are subject to environmental conditions. Major or full routine maintenance or interventions are conducted offline and are necessary to examine asset components that cannot otherwise be inspected or monitored.

Examples of the way that consumable components wear out include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts, wearing of pump seals, perishing of gaskets, and pitting of insulators. As indicated in Figure 6.2, continued operation of such components will eventually lead to failure.

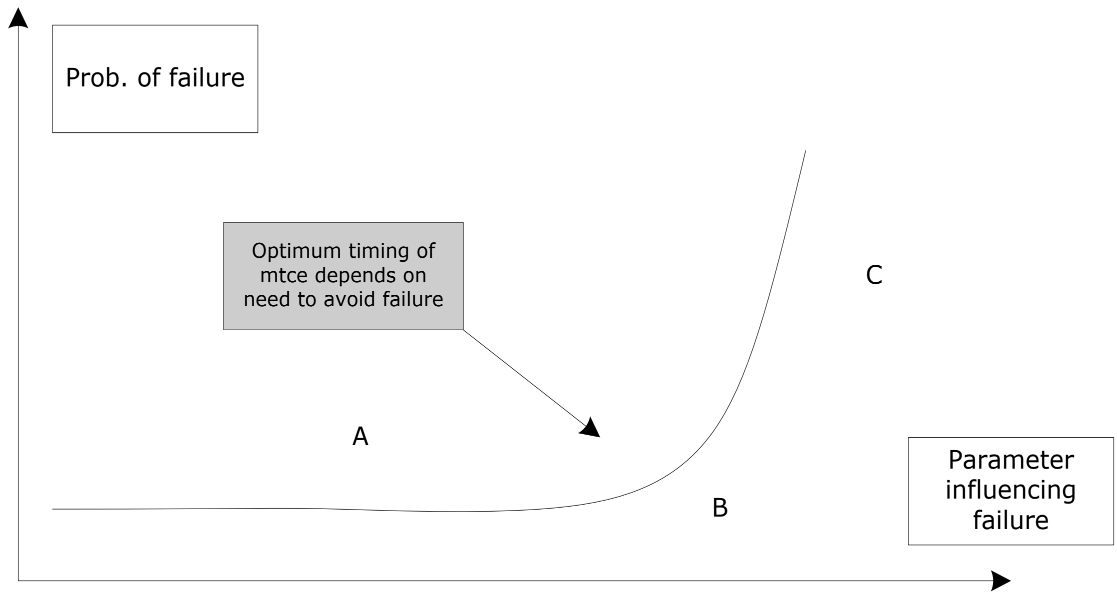

Figure 6.2 Component failure

Failure of components is usually based on physical characteristics. Exactly what leads to failure may be a complex interaction of variables such as:

- quality of manufacture
- quality of installation
- age
- operating hours
- number of operations
- loading cycle
- stress of components due to fault current or overvoltage events
- ambient temperature
- previous maintenance history
- environmental factors and presence of contaminants.

We determine when to perform maintenance based on the need to avoid failure. For example, the need to avoid failure of a 15 kVA transformer supplying a single consumer is low and may be operated out to point C, whereas a 33/11 kV substation transformer may be operated to point B due to a higher need to avoid failure. Modern protection relays and battery systems in zone substations are critical to the safe and reliable operation of the network and are only operated to point A.

The trade-off of avoiding failure is the increased cost of labour and consumables over the asset life cycle, along with the cost of the unused component life. Fixed operational maintenance costs are associated with regular monitoring of the condition of the assets and protecting the components while in service.

We base all our maintenance decisions on safety and cost-benefit criteria. The principal benefits are avoidance of hazardous conditions and supply interruptions. We closely monitor assets that supply large consumers, or a large number of consumers, and have an associated safety risk. Assets supplying only a few consumers and do not have an associated safety risk, such as a 15 kVA transformer, are more likely to be run to failure.

The maintenance strategy map in Figure 6.3 broadly describes our adopted maintenance strategy.

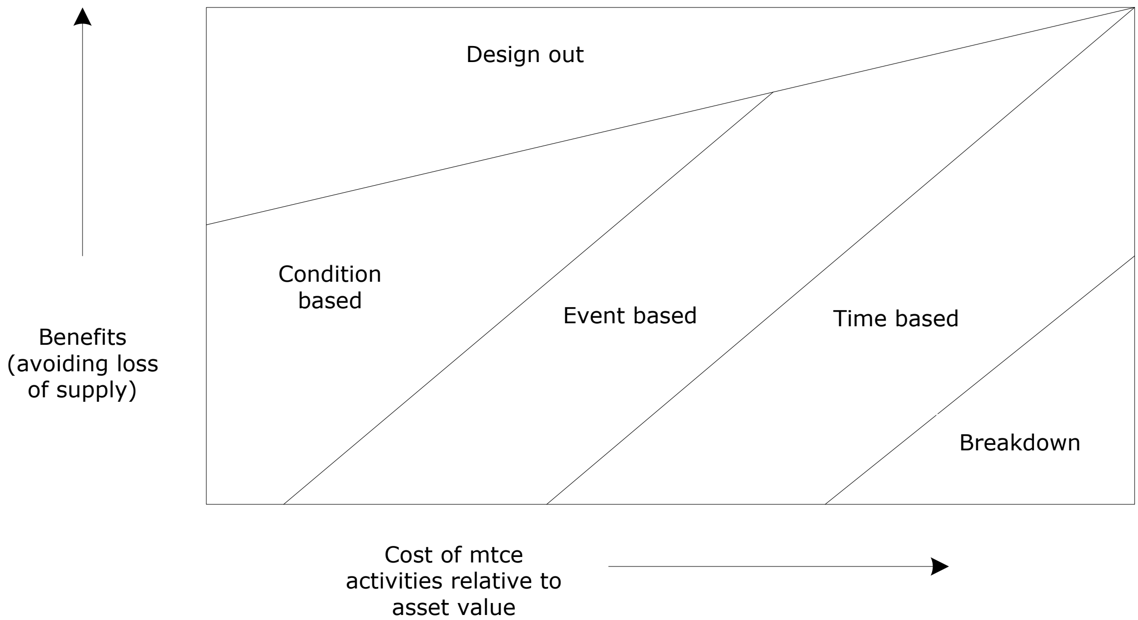

Figure 6.3 Maintenance strategy map[44]

Asset condition assessment requires regular maintenance inspections and testing, at times interfering with the immediate operational efficiency of equipment. However, failing to undertake maintenance inspections could lead to safety risk and greater loss of efficiency due to consequential failure of equipment causing a prolonged outage. The timing and frequency of inspection is chosen in balance with the risk and effects of an outage.

Component condition is the key trigger for maintenance. The precise conditions that trigger maintenance are very broad, ranging from oil acidity to dry rot. Table 6.5 describes the maintenance triggers we look for.

[44] The map indicates that where the benefits are low, i.e. there is little need to avoid LOS, and where costs of maintenance are high, it is appropriate to run the asset to failure. As the value of an asset and the need to avoid LOS increases, we rely less on easily observable proxies such as calendar age, running hours, or number of trips to signal condition. Instead, we rely on actual component condition such as DGA for transformer oil, or below ground inspection of remaining timber diameter for hardwood poles. Please note that the map does not address asset maintenance for health and safety reasons, e.g. ground mounted LV distribution boxes, which could be run to failure were it not for the safety risk.

Asset category	Components	Maintenance trigger
LV lines and cables	Poles, arms, stays, and bolts	• evidence of dry-rot • concrete fatigue/steel showing • loose bolts, moving stays • rusted hardware • displaced arms
	Pins, insulators, and binders	• obviously loose pins • visibly chipped or broken insulators • rusted pins • visibly loose binder • thermographic evidence of unusual heating of components and/or connections
	Conductor	• visibly splaying or broken conductor • corroded or annealed conductor • thermographic evidence of unusual heating of components and/or connections
	LV distribution and link boxes	• visible rust or corrosion • broken or damaged hinges or cover fixings • cracked or worn fibreglass/plastic • cracked or broken concrete • thermographic evidence of unusual heating of components and/or connections
Distribution substations	Poles, arms, and bolts	• evidence of dry-rot • loose bolts, moving stays • rusted hardware • displaced arms.
	Enclosures	• visible rust • broken or damaged hinges or cover fixings • cracked or worn fiberglass/plastic • cracked or broken masonry
	Transformer	• excessive oil acidity (500 kVA or greater) • visible signs of oil leaks • excessive moisture in breather • visibly chipped or broken bushings • excessive rust • thermographic evidence of unusual heating of components and/or connections
	Pole mounted enclosed switches	• excessive oil acidity • visible signs of oil leaks

Asset category	Components	Maintenance trigger
		• excessive carbon in oil • visibly chipped or broken bushings • excessive moisture in oil • excessive rust • thermographic evidence of unusual heating of components and/or connections • partial discharge evidence of unusual current leakage in insulation • recloser controller batteries' age
	Ground-mounted switches	• excessive oil acidity • visible signs of oil leaks • excessive carbon in oil • visibly chipped or broken bushings • excessive rust • broken or damaged hinges or cover fixings • excessive moisture in oil • poor resistance test of fuse • corroded fuse carrier • significant partial discharge detected • thermographic evidence of unusual heating of components and/or connections
	Regulators	• excessive oil acidity • visible signs of oil leaks • excessive carbon in oil • visibly chipped or broken bushings • excessive moisture in oil • stability of regulating control system • excessive rust • thermographic evidence of unusual heating of components and/or connections • regulator controller batteries' age
Distribution lines and cables	Poles, arms, stays, and bolts	• evidence of dry-rot • concrete fatigue/steel showing • loose bolts, moving stays • rusted hardware • displaced arms
	Pins, insulators, and binders	• loose pins • chipped or cracked insulators

Asset category	Components	Maintenance trigger
		• rusted pins • fouled insulators • broken or chaffed binders • thermographic evidence of unusual heating of components and/or connections
	Conductor	• chaffed conductor • inadequate ground clearance • unequal sag in span • corroded or annealed conductor • obsolete conductor • thermographic evidence of unusual heating of components and/or connections • partial discharge evidence of unusual current leakage in insulation
	Air break switches and fuses	• poor resistance test of fuse • corroded fuse carrier • excessive rust • thermographic evidence of unusual heating of components and/or connections
Zone substations	Fences and enclosures	• defects in earthing points • check security of fence and gates • gaps below gates and fences allowing access • electric fence operation • condition of materials—rust, damage, fatigue, and so on
	Buildings	• secure, waterproof, vermin and bird proof • fittings corroding • condition of paint and finishings
	Bus work and conductors	• insulars chipped or cracked • burn or tracking marks • thermographic evidence of unusual heating of components and/or connections • loose droppers, hot connectors • earthing not intact and connected • birds' nests
	33 kV and 110 kV switchgear	• unusual noises • oil leaks • broken bushings • droppers loose

Asset category	Components	Maintenance trigger
		• position indicator not legible • earthing leads not intact and connected • mechanism and recharge spring not operating • protection not operating correctly • cyclometers not operating • unusual heating evidenced by odour, smoke, discolouration of surfaces, and/or distortion of materials • corrosion • significant partial discharge detected in switchgear • thermographic evidence of unusual heating of components and/or connections
	Transformer	• rust and paint not in good condition • oil leaks, covers not secure • broken bushings, droppers loose • OLTC position indicator not legible • earthing leads not intact and connected • Earthing leads not intact and connected • inadequate seismic constraint • DGA oil test results poor / breather maintenance • unusual noise • fans and pumps not operating • thermal and temp alarms and trips not operating • Bucholz relay site glass not clean • Bucholz relay site glass containing oil • OLTC not operating correctly • thermographic evidence of unusual heating of components and/or connections
	11 kV switchgear	• unusual noises • unusual heating • oil leaks • broken bushings, droppers loose • corrosion • position indicator not legible • earthing leads not intact and connected • mechanism and recharge spring not operating

Asset category	Components	Maintenance trigger
		correctly • protection not operating correctly • cyclometers not operating • significant partial discharge detected in switchgear • thermographic evidence of unusual heating of components and/or connections
	Station batteries	• battery rectifier not operating correctly • battery cell voltages not to spec • loose connections
	Instrumentation	• protection relays not maintaining correct settings or displays • meters not reading • trip flags not activated • alarms not operating correctly • warning flags/lamps/LEDs/displays indicating faulty operation
Sub-transmission lines and cables	Poles, arms, stays, and bolts	• evidence of dry-rot • concrete fatigue / steel showing • loose bolts, moving stays • rusting hardware • displaced arms
	Pins, insulators, and binders	• loose pins • chipped or cracked insulators • fouled insulators • rusted pins • broken or chaffed binders • thermographic evidence of unusual heating
	Conductor	• chaffed conductor • inadequate ground clearance • unequal sag in span • corroded or annealed conductor • obsolete conductor • significant partial discharge detected in cables • thermographic evidence of unusual heating
	Switchgear	• recloser controller batteries' age

Table 6.5 Maintenance triggers

The details of our responses to maintenance triggers can be found in our policies, maintenance standards, and work plans. An outline of our maintenance policies and work plans is given in Section 6.9.1—Maintenance policies and Section 6.9.2—Maintenance work plans.

Typical responses to maintenance triggers are described in Table 6.6.

Asset class	Trigger	Response to trigger	Approach
Sub-transmission lines	Loose or displaced components	Tighten or replace	Condition as revealed by inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by inspection
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
Zone substation transformers	Oil acidity	Filter oil	Condition as revealed by annual DGA test
	Excessive moisture in breather	Replace crystals in filter; check seals of breather; check moisture in oil; filter oil if necessary.	Condition as revealed by monthly inspection
	Weighted number of through faults	DGA Test; possibly filter oil, de-tank and refurbish; review protection	Event driven
	General condition of external components	Repair or replace as required	Condition as revealed by monthly inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
Distribution lines	Loose or displaced components	Tighten or replace	Condition as revealed by inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by routine inspection
	Cracked or broken insulator	Replace as required	Breakdown

Asset class	Trigger	Response to trigger	Approach
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by routine inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
RMUs (and other ground mounted, enclosed, 11 kV switches)	Rusty, broken or cracked enclosure where fitted	Make minor repairs unless renewal is required	Condition as revealed by routine inspection
	Oil acidity	Filter or change oil	Full maintenance every five years
	Visible oil leaks	Remove to workshop for repair or renewal if serious	Condition as revealed by routine inspection
	Chipped or broken bushings	Replace	Breakdown or condition as revealed by five-year inspection
	Significant partial discharge detected in switchgear	Make minor repairs or remove to workshop for repairs/replacement	Condition as revealed by routine inspection
Distribution and sub-transmission reclosers	Weighted number of light and heavy faults	Repair or replace contacts, filter oil if applicable	Event driven
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
	Controller batteries' age	Replace batteries as per manufacturer's manual	Maintenance cycle to suit batteries' replacement
Distribution ABSs	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by routine inspection
	Seized or tight	Lubricate or replace components as required	Breakdown
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
Distribution transformers	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by routine inspection
	Rusty, broken or cracked enclosure	Make minor repairs unless	Condition as revealed

Asset class	Trigger	Response to trigger	Approach
	where fitted	renewal is required	by routine inspection
	Oil acidity—only check ground mounted txfrs of 500 kVA or greater	Filter oil or change transformer	When removed from service for full external maintenance every 15 years
	Excessive moisture in breather where fitted	Change crystals, check breather seals, filter oil	Condition as revealed by routine inspection
	Visible oil leaks	Remove to workshop for repair or renewal if serious	Condition as revealed by routine inspection
	Chipped or broken bushings	Repair or replace, according to severity of chip.	Breakdown or condition as revealed by routine inspection
	Enclosures (for ground mounted dist subs) have: •visible rust •broken or damaged hinges or cover fixings •cracked or worn fiberglass/plastic •cracked or broken masonry	Repair or replace affected component	Conditions as revealed by annual inspection, or routine detailed condition assessment, or during 15 year full maintenance
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
LV lines	Loose or displaced components	Tighten or replace	Breakdown unless revealed by ten yearly inspection.
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	10-yearly inspection
	Cracked or broken insulator	Replace as required	Breakdown unless revealed by 10-yearly inspection
	Splaying or broken conductor	Repair conductor unless renewal is required	Breakdown unless revealed by 10-early inspection

Asset class	Trigger	Response to trigger	Approach
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
LV distribution and link boxes	Visible rust or corrosion	Repair or replace affected component	Condition as revealed by five-yearly inspection
	Broken or damaged hinges or cover fixings	Repair or replace affected component	Condition as revealed by five-yearly inspection
	Cracked or worn fibreglass/plastic	Repair or replace affected component	Condition as revealed by five-yearly inspection
	Cracked or broken concrete	Repair or replace affected component	Condition as revealed by five-yearly inspection
	Thermographic evidence of unusual heating of components and/or connections	Repair or replace affected component	Condition as revealed by five-yearly inspection

Table 6.6 Typical responses to maintenance triggers

6.4 Renewing assets

We classify work as 'renewal' if there is no change in functionality (i.e. the output of the asset does not change).

A key criterion for renewing an asset is determining whether capitalised operation and maintenance costs are exceeding the renewal cost. The renewing assets criterion can be met in the following ways.

- Operating costs become excessive—for example, the cost of switching to enable maintenance or repairs is greater than the cost of renewal.
- Maintenance costs begin to accelerate—for example, a transformer needs more frequent oil treatment as windings and insulation paper reach end of life or as the seals and gaskets perish.
- Maintenance costs of new equipment are less than older existing assets—for example, 'maintenance free for life' vacuum and SF_6 insulated MV circuit breakers compared to oil insulated circuit breakers that require regular and fault operation related oil changes and contact servicing.
- Supply interruptions due to component failure become excessive.

- Renewal costs decline, particularly where costs for new technologies like SCADA decrease by several fold.

6.4.1 Refurbishment

Refurbishment involves the replacement of individual components and is done to extend the life of an asset. For example, if 30% of the poles on an overhead line are replaced with new poles, crossarms, and insulators, and assuming that the pole structures represent 70% of the cost of the line, the line was 40 years old, and had an estimated useful life of 50 years, then:

Remaining life before refurbishment:	10 years
Remaining life after refurbishment:	= 30 years x 10 years
	+ 70% x 70% x 50 years
	+ 30% x 70% x 50 years
	= 18.4 years

At year 50, another 40% of the poles could be replaced, with the remaining 30% replaced at year 60. The remaining life of the line is reducing, meaning that Capex will need to increase in future years.

6.4.2 Renewal triggers

Table 6.7 lists the renewal triggers for key asset classes.

Asset category	Components	Renewal trigger
LV lines and cables	Poles, arms, stays, and bolts Pins, insulators, and binders Conductor LV distribution/link boxes	Condition based replacement
Distribution substations	Poles, arms, and bolts Enclosures Transformer Switches and fuses Cable terminations, joints Ringmain switches, and so on	Condition based replacement
	Reclosers, sectionalisers	Condition based replacement Controller batteries by age or condition, whichever is sooner
	Regulators	Condition based replacement or maintenance costs exceed replacement Controller batteries by age or condition, whichever is sooner
	Poles, arms, stays, and bolts Pins, insulators, and binders Conductor	Condition based replacement
	Cable terminations, potheads,	Condition or age based replacement

	joints	
Zone substations	Fences and enclosures	Condition based replacement or maintenance costs exceed replacement
	Buildings	Maintenance costs exceed replacement
	Bus work and conductors	Condition based replacement or maintenance costs exceed replacement
	33 kV switchgear	
	Transformer	
	11 kV switchgear	
	Cable terminations, cable boxes, joints	Condition or age based replacement
	Batteries and chargers	Age or condition, whichever is sooner
	Instrumentation	Maintenance costs exceed replacement or equipment obsolete or age limit reached
Sub-transmission lines and cables	Poles, arms, stays, and bolts	Age and condition based replacement
	Pins, insulators, and binders	
	Conductor	
	Cable terminations, potheads, joints	Condition or age based replacement.
SCADA and radio	SCADA, radio, ripple control, and comms cables	Age and condition based replacement
Unspecified items	Unspecified	
Our equipment within GXP		Condition based replacement or maintenance costs exceed replacement or equipment obsolete

Table 6.7 Renewal triggers

In accordance with our policies, classes of assets are renewed when:

- an operational or public safety hazard is likely
- capitalised operations and maintenance costs exceed renewal costs
- continued maintenance will not satisfy required service levels.

6.5 Upsizing or extending assets

If any of the capacity triggers are exceeded, we will consider upsizing or augmenting our network. The difference between the two modes of investment is described in Table 6.8.

Characteristic	Upsizing	Extension
Location	Within or close to existing network footprint (within a span or so)	Outside of existing network footprint
Load	Can involve supply to a new connection within the network footprint or increasing the capacity to an existing connection	Almost always involves supply to a new connection

Characteristic	Upsizing	Extension
Upstream reinforcement	Generally forms the focus of up-sizing	May not be required unless upstream capacity is constrained
Visible presence	Generally invisible	Obviously visible
Quadrant in Figure 5.1	Either 1 or 2 depending on rate of growth	Either 3 or 4 depending on rate of growth
Necessity	Possible to avoid if sufficient surplus capacity exists. Possible to avoid or defer using tactical approaches described in Section 5.2.1	Generally can't be avoided—a physical connection is required
Impact on revenue	Difficult to attribute revenue from increased connection number or capacity to up-sized components.	Generally results in direct contribution to revenue from the new connection at the end of the extension
Impact on costs	Cost and timing can vary and be staged	Likely to be significant and over a short time
Impact on ODV	Could be anywhere from minimal to high	Could be significant depending on length of extension and any consequent up-sizing required
Impact on profit	Could be anywhere from minimal to high	Could be minimal depending on level of consumer contribution
Means of cost recovery	Most likely to be spread across all consumers as part of on-going line charges	Could be recovered from consumers connected to that extension by way of capital contribution
Nature of work carried out	Replacement of components with greater capacity items	Construction of new assets

Table 6.8 Difference between upsizing and extending the network

6.5.1 Designing new assets

We use a range of technical and engineering standards to achieve an optimal mix of the following outcomes.

- Meet likely demand to a reasonable time horizon, having considered issues such as modularity and scalability.
- Minimise overinvestment.
- Minimise risk of asset stranding.
- Minimise corporate risk exposure with other goals.
- Maximise operational flexibility.

- Maximise the fit with soft organisational capabilities such as engineering and operational expertise and vendor support.
- Comply with environmental, and employee and public safety requirements.

Given the simple nature of our network, standardised designs are generally adopted for all asset classes, with minor site-specific alterations. Our standard designs represent current standards, industry guidelines, and manufacturers' recommendations.

6.5.2 Building new assets

Both internal staff and external contractors are used for upsizing or extending assets. As part of the building and commissioning process, the information records are as-built and all testing is documented.

6.6 Enhancing reliability

Our consumers have voiced a preference to receive 'about the same' reliability in return for paying' about the same' line charges (Section 4.5.1—Consumer service level preferences). There is no mandate to improve reliability simply because it can be improved, but there is a mandate to maintain supply.

There are many factors that can lead to a decline in reliability over time, for example:

- tree regrowth
- declining asset condition, especially in coastal marine areas
- extensions to the network that increase its exposure to trees and weather
- growing consumer numbers that increase lost consumer-minutes (SAIDI) for a fault
- installation of requested asset alterations that increase reliability risk
- increase in frequency and magnitude of extreme weather conditions due to climate change

Our reliability enhancement programme includes the following steps:

- identifying the consumer-minutes lost for each asset by cause
- identifying the scope and likely cost of reducing the lost consumer-minutes
- estimating the likely reduction in lost consumer-minutes if work is implemented
- calculating the cost of each enhancement opportunity per consumer-minute
- prioritising the enhancement opportunities by cost from lowest to highest.

6.7 Converting overhead to underground

Conversion of overhead line to underground cable is does not fit neatly within the asset life cycle—conversions tend to be driven more by aesthetics than technical reasons and, consequently, rely on other utilities sharing the cost. However, in certain circumstances and geographic locations, conversion from overhead to underground limits or eliminates the risk of network damage and outages from extreme weather events (e.g. wind and snow storms). Where renewal or upsizing of overhead assets is needed, placing the new assets underground may be the best engineering and/or economic solution. Similarly, where renewal or upsizing of existing outdoor switchgear in zone substations is required, a replacement of outdoor switchyards with indoor switchrooms and switchgear may be preferred.

In built up areas, public safety risk reduction or elimination may influence the decision on renewing an overhead line or replacing it with underground cable. Difficulties in gaining access for maintenance, due to location and proximity to private or public premises, may encourage not only relocating the line but also undergrounding it. For example, within the Timaru City area there is a number of 11 kV and 33 kV lines that cross built-up areas. Consideration may be given to undergrounding overhead lines for safety and access reasons, before age or condition prompts renewal or upgrading.

We apply the engineering definition of risk as the product of probability of an event and the consequences of that event. Risk is usually measured in dollars to enable comparison with other options. More detail on risk management can be found in Section 7.4—Risk management planning for network assets.

6.8 Retiring assets

Retiring assets involves doing most, if not all, of the following activities:

- de-energising the asset
- physically disconnecting from other live assets
- physically removing the asset from location or abandoning in-situ (underground cables are typically abandoned)
- disposing of the asset in an appropriate manner, particularly if it contains SF_6, oil, lead, or asbestos.

Key criteria for retiring an asset include the following:

- its physical presence is no longer required, usually because demand has reduced or ceased
- it creates unacceptable risk exposure because its inherent risks have increased over time, or because emerging trends of safe exposure levels are declining[45]
- better options exist to create a similar outcome[46] and there are no suitable opportunities for redeployment
- a replacement asset has been upgraded a no suitable opportunities for redeployment exist.

[45] Assets retired for safety reasons are not redeployed or sold for reuse.
[46] For example, replacing lubricating bearings with high-impact nylon bushes.

6.9 Routine and preventive inspection, maintenance, and performance programmes

6.9.1 Maintenance policies

Maintenance work comprises of three main elements:

- routine inspections and testing to identify the condition of the asset
- evaluation of results to establish an appropriate course of action
- repair, refurbishment, and replacement of assets if condition requires corrective action.

We are developing objective defect criteria for condition based assessments. We give careful consideration to the selection of each criterion in order to avoid in-service failure and premature replacement. With the exception of some smaller items (e.g. station batteries), assets are not replaced based on age or other generic criteria but are kept in service until maintenance becomes uneconomic or they pose a safety or reliability risk.

Periodic inspections, patrols, servicing, and test work is carried out to ensure that defects or emerging risks are identified so that corrective action can be undertaken. Servicing can involve minor component replacement (e.g. seals, bushings, etc.) but does not involve significant repairs.

The course of corrective action taken is usually the most economical, provided it does not jeopardise safety or reliability of supply. Repairs can be carried out directly following a fault-induced outage when restoring service. Work may involve temporary or permanent repair of the faulted asset—the objective is to restore service as quickly as possible by the most economical method. If further intervention is required, a planned outage may be needed.

Maintenance requirements are also influenced by network development projects that involve the decommissioning of assets such as when assets are replaced due to high network demand growth and are unable to reach expected service life. Maintenance strategies and programmes are reviewed regularly to ensure that the network is being maintained in an efficient and cost-effective manner.

6.9.2 Maintenance work plans

Our Asset Management Team raises a new set of maintenance jobs each financial year through our financial and asset management systems, thereby creating purchase orders throughout the year to cover maintenance work undertaken by our contractors. The Team uses maintenance jobs and purchase orders to provide strategic control of maintenance that is planned and executed at a tactical level by NETcon and other contractors.

Table 6.9 lists the three dimensions of control and the jobs associated with each dimension.

Dimension	Job type
Maintenance type	• routine and preventive • refurbishment and renewal • fault and emergency
Asset category	• LV lines and cables • distribution substations • distribution lines and cables • zone substations • sub-transmission lines and cables • SCADA, comms, and ripple load control
Periodicity	• immediate—fault and emergency • special one-off projects such as condition assessment of all items of a particular asset type, e.g. distribution boxes • monthly checks • six-monthly or annual inspection and minor maintenance • full maintenance periodicity defined by asset requirements

Table 6.9 Three dimensions of control and associated jobs

There are also specific jobs included in the annual set: overall scheduled maintenance planning and the associated analysis of asset maintenance records, condition assessment reports, and other maintenance related asset data. The contractors' scheduled maintenance work plans include routine visits for testing, inspection, cleaning, maintenance and minor repairs. Any defects requiring urgent major repairs are attended to in special visits. Check sheets and reports from routine and subsequent visits are filed for future reference and analysis.

Scheduled work is listed in Table 6.10.

Asset type	Description of scheduled work
Zone substations	• monthly checks and cleaning • annual checks and minor maintenance • off-line (or full) maintenance programs with periods and actions generally as specified by suppliers or determined from experience or local conditions
Urban distribution substations (generally over 100 kVA): ground mounted, underground, and 2-pole structure	Annual checks and minor maintenance include: • routine maintenance programs and special checks and maintenance (such as after heavy rain for underground subs) • offline (or full) maintenance programs with periods and actions determined from equipment supplier's recommendation, our experience, and local conditions.

Asset type	Description of scheduled work
All substations (including single-pole mounted equipment)	Routine checks in association with earth tests
System-wide assets	Periodic tests such as partial discharge of circuit breakers and cables, thermographic checks of visible current carrying parts, and oil sample tests for transformers

Table 6.10 Scheduled work

Unscheduled work includes:

- inspections
- testing
- repairs or replacement of assets for
  - reported damage or deterioration
  - system fault damage
  - asset failure
  - environmental effects.

6.9.2.1 Zone substations, ground mounted distribution substations, and enclosed MV switchgear and regulators

We have engaged NETcon to prepare, maintain, and execute a comprehensive routine maintenance programme for all our zone substations; ground mounted, underground, and two-pole distribution substations; and MV enclosed switches and regulators.

When checks reveal the need for immediate or more detailed maintenance, non-routine maintenance is scheduled. The maintenance may include onsite intervention or removal to the contractor's workshop (maintenance is undertaken onsite if possible). Maintenance may be undertaken earlier than scheduled while the asset is out of service for urgent work, and the date of the next round of maintenance is rescheduled.

6.9.2.2 Overhead lines and pole mounted assets

NETcon undertakes overhead line patrols, pole inspections, and maintenance of our 33 kV, 11 kV, and LV lines. The inspection and maintenance is directed by us, on a job-by job basis, with programming guided by age and condition of lines, poles, and associated assets. Our aim is to inspect all lines over 25 years of age every 10 years.

6.9.2.3 Partial discharge mapping of 11 kV sub-transmission cables

Partial discharge (PD) mapping tests of the TIM sub-transmission cables interconnecting TIM GXT and GRM, NST, and HNT substations have been done every two years, beginning in 2006. The maps are compared with previous years' maps to glean valuable asset condition information (particularly the state of the 11 kV cable joints). Two new 11 kV sub-transmission cables[47] from TIM to NST were PD mapped in 2012 and will also be retested on a biennial cycle.

6.9.2.4 Partial discharge testing of indoor and ground mounted switchgear

A programme of partial discharge testing is undertaken for all indoor HV and MV switchboards and outdoor ground mounted 11 kV switchgear. The tests are generally carried out biennially, with more frequent tests for assets that have exhibited partial discharge levels.

Depending of the nature of the partial discharge levels, repeat tests may be undertaken at 6, 12, or 24 month intervals. Where partial discharge levels increase significantly or are persistently high, immediate intervention is ordered, with switchgear taken out of service, inspected, and maintained as necessary.

6.9.2.5 Thermographic inspections

Thermographic inspections on hotspots on outdoor or exposed insulators and fittings on outdoor installations have been undertaken on a small scale for several years. We intend to increase the frequency and extent of themographic inspections.

6.9.2.6 Services provided by NETcon as part of our maintenance programme

Table 6.11 describes the substation maintenance provided by NETcon.

Maintenance type	Description
Routine condition assessment	Zone substation assets: monthly sub checks. RMUs, distribution subs (building, kiosk, padmount, and enclosure types) and zone substations: – annual, visual on-line inspections only – periodic detailed inspections as part of off-line full maintenance. –
Urgent reactive maintenance	Zone substation assets: immediate. Distribution substations: buildings, kiosks, padmounts, and enclosures: immediate.
Planned routine full maintenance	Zone substation assets: – four-yearly cycle for protection systems; – periodic[48], off-line, maintenance.

[47] The cables are 33 kV rated for possible future 33 kV GXP.

Maintenance type	Description
	RMUs and distribution substations (buildings, kiosks, padmounts and enclosures): 5/15 year cycles.*[49]

Table 6.11 NETcon substation maintenance

6.9.3 Defect identification process

Regular maintenance inspections are carried out by our contractors (mainly NETcon) to determine the condition of the network. Condition assessment reports are submitted to us, and repair and maintenance work is scheduled. Urgent repairs are undertaken immediately after notifying our control room and receiving appropriate permits, operating instructions, and clearances.

Routine maintenance visits are scheduled based on manufacturers' recommendations, best industry practice, and field experience. The reports submitted to us include a description of the work done and any other matters requiring attention. Matters raised may result in a reactive order for repairs or a special condition assessment. Zone substations are inspected monthly, while ground mounted distribution substations are inspected annually.

6.9.3.1 Special condition assessment projects

Special, one-off condition assessment programmes are initiated from time to time. Programmes are tailored to specific needs that are not met by existing maintenance programmes. For example, the detailed inspection of all LV distribution and link boxes throughout our network, undertaken in 2010.

In another example, a one-off set of PD mapping of selected main 11 kV feeder cables in the Timaru CBD was conducted in 2011. The PD mapping was initiated in response to several cable joint failures in the CBD in the previous four years. The cables selected for mapping had several joints per section (or at least one joint of the 1987 era) that appeared prone to failure. Following analysis of the results, replacement of the suspect joint or whole cable sections was rejected. The risk and cost associated with leaving the joints to fail in the future were less than that of attempting immediate replacement of all joints. The data collected is retained to quickly locate and repair any future faulty joint.

Data collected from special assessments is analysed by our engineers with assistance from NETcon maintenance planners. Planned and coordinated action to correct deterioration and defects is then instigated. Action may be organised by geographical area or a particular type of defect correction, in order to optimise maintenance resources. Action involving many assets may be grouped into a Capex project. Any urgent or safety compromising faults

[48] 'Periodic' refers to "x-year cycle', 'x' being specific to each type, make, and model of asset in accordance with our Maintenance Standards and the asset manufacturer's manuals and recommendations.
[49] RMUs have a five-year cycle—the cycle will be reviewed once condition assessment is completed. The rest of the distribution sub assets have a 15-year cycle. Many RMUs have not been maintained in over 20 to 30 years accordingly present condition is unknown and poses an unacceptable risk.

found during inspection are fixed immediately by the contractor or referred to us for immediate action.

6.9.4 Serious defect rectification process

When a serious defect in plant or equipment is discovered, NETcon is authorised to take immediate action to correct the defect, or make the asset safe, if the defect constitutes:

- safety risk to the public or employees
- danger to continuity of supply
- risk of damage to the network,

Depending on the nature and urgency of the corrective action required, and the need for network access or permissions, our Control Room is notified of the defect as soon as it is discovered or immediately following corrective action. Minor defects may also be dealt with by the contractor.

All defects, major or minor, are submitted as 'Plant Fault Reports' to our Control Room where the fault is logged and referred for action (if required) before being passed to the Asset Management department for decision on the asset(s) involved. The department may decide to:

- issue a reactive maintenance order (major)
- schedule subsequent routine maintenance visits
- initiate a special project dependent on the type, size, and seriousness of the defect
- take no immediate action, but note for possible future action (minor).

6.9.5 Routine maintenance system

Table 6.12 summarises our routine maintenance system.

Asset class	Routine maintenance type	Frequency
Zone substations	Monthly inspection and clean.	Monthly
Zone substations	Six monthly detailed inspection, battery charger maintenance plus 12-monthly earth testing and protection relay settings check and test	Six-monthly, with some items only 12 monthly
Zone substations	Detailed maintenance of assets in accordance with the suppliers' recommendations, and our Maintenance Standards (in preparation)	Annually for certain items, biennially for others, four-yearly for protection systems, and otherwise to supplier's

Asset class	Routine maintenance type	Frequency
Ground mounted distribution substations and switches, 200 kVA	Annual visual inspection, including minor cleaning/maintenance, twice yearly MDI reading	Annual (MDIs: six-monthly, in spring and autumn)
Ground mounted, underground, and 2-pole distributions substations and switches with 200 kVA or greater txfrs	Full maintenance of substation/switchgear, including cleaning, testing of oil/insulation, routine maintenance to suppliers' recommendations	Five yearly when RMU present; every 15 years when no RMU present
Sub-transmission cables	Partial discharge mapping	Biennially
TIM 11 kV sub-transmission switchboards (GRM, HNT, and NST)	Partial discharge tests	Annually, for the older switchgear (HNT), otherwise every 24 months as per 11 kV RMUs
11 kV RMUs throughout system	Partial discharge tests	6 to 12 months if condition warrants, otherwise every 24 months
33 kV and 11 kV switchboards in zone substations	Partial discharge tests	Condition and age based, as required, otherwise every 24 months
Pole mounted transformers	Inspection and earth test—minor in-situ maintenance	Every 5 to 10 years, according to condition based need
Single-pole mounted transformers	No full maintenance	Replace when fails, or has less than 10 years remaining life
Pole mounted enclosed HV & MV switches (recloser,	Inspection and earth test—inor in-situ maintenance	Annually

Asset class	Routine maintenance type	Frequency
sectionalisers)		
Pole mounted enclosed HV & MV switches (recloser, sectionalisers)	Full maintenance	5 to 10-yearly or more frequently if manufacturer, condition or age demands
Regulators (11 kV)	Yearly inspection and clean—Minor in-situ maintenance, including battery system, software, earthing checks	Annually
Regulators (11 kV)	Full maintenance, including oil and operational tests and associated assets—Corrosion treatment and water proofing	Five-yearly or more frequently if specified by supplier
Capacitors (11 kV line regulation type)	Inspect and test capacitance, check fuses, and maintain associated assets	Five-yearly or more frequently if specified by supplier
Pole lines, including associated overhead fittings and assets	All lines older than 25 years (or younger if condition dictates), inspection of poles, line fittings, conductors, disconnectors, fuses, and so on	10-yearly, with scheduling based upon age and condition

Table 6.12 Routine maintenance system

NETcon undertakes a close inspection of all new equipment and makes any necessary additions and modifications to the protective coatings and water sealing in order to reduce ongoing maintenance and extend the life of the asset.

6.10 Maintenance plans for the next 12 months

Section 6.10 discusses our maintenance plans and presents our maintenance expenditure projections. For information on how our maintenance plans take our service level targets in to account, please see Section 4.4.5—10-year reliability targets.

6.10.1 Sub-transmission lines and cables

The 2016/17 Opex budget for annual expenditure on sub-transmission lines and cable maintenance is $31,000.

33 kV sub-transmission lines and cables are the highest priority

The fourteen 33 kV sub-transmission lines have the highest impact on network reliability. Sub-transmission lines are built to the highest standard of resilience and, in the case of Clandeboye and PAR, have duplicate circuits to provide security. The remaining lines are single 33 kV circuits.

The six 11 kV sub-transmission cables from TIM GXP to Timaru CBD zone substations include those added in 2011/12. The two new cables are 33 kV rated, but are operated at 11 kV between TIM 11 kV GXP and NST substation. Should a 33 kV GXP be introduced at TIM GXP in the future, the cables will be operated at 33 kV.

The new 110 kV double circuit line from BPD substation to the new CNR zone substation was commissioned in 2014 and is currently operated at 33 kV with both circuits paralleled.

The sub-transmission lines built in the last 10 to 12 years will be due for inspection and maintenance in the 20th year of service, unless condition calls for earlier inspection. Our sub-transmission line inspection priority is summarised in Table 6.13.

Location of line	Year of construction	Inspection priority
TIM sub to PAR sub #1	1979 and 1985	1
TIM sub to PAR sub #2	1963	2
TIM sub to PLP sub	1977	3
TMK sub to GLD sub	1966	4
TMK sub to Winchester Township	1979	5
Winchester Township to RGA sub	2003	12
TMK sub to Clandeboye sub	1997	10
ABY sub to FLE sub	1967	6
OPU Dam to FLE sub	1997	7
TEK sub to Mt Cook sub	between 1975 and 2001	8 and 11
TKA to TEK sub	1991	9
TWZ to TVS sub	1968	7
CNL CB to RGA sub	2010	13
BPD sub to CNR sub	2014	14

Table 6.13 Sub-transmission line inspection and maintenance priority

6.10.2 Zone substations

The 2016/17 Opex budget for annual expenditure on zone substation maintenance is $482,000.

6.10.2.1 Routine inspections

All zone substations are inspected on a biannual detailed inspection cycle that includes battery and rectifier maintenance.

Zone substations are visited on a monthly cycle for cleaning and routine visual inspections of switchgear, protection, instrumentation, and monitoring readings of temperature, tap change operations, breaker operations, protection flag resets, battery charger status, and maximum demand indicators.

Unplanned visits take place when a feeder fault operates a substation circuit breaker, requiring an operator to review and reset flags before commencing restoration procedures.

Regular zone substation inspections also include buildings and other assets such as fire protection and security systems. Periodic maintenance of the grounds includes lawn mowing, pruning, weed control, and clearing of drains.

6.10.2.2 Protection systems

Protection system maintenance is needed to confirm that the protection is calibrated within tolerance and will operate as required. The introduction of microprocessor protection relays, with internal self-testing and monitoring software, has reduced the need for more frequent testing of assets. The older legacy electromechanical protection relays, however, still require biennial testing and adjustment.

All zone substation relay and circuit breaker control systems are secondary injection and operationally tested at least every four years, in accordance with the Electricity Industry Participation Code (Part 8), our relevant Maintenance Standards, and to manufacturers' recommendations.

The quadrennial testing incorporates any required maintenance. Prior to testing, protection scheme reviews are conducted and any changes to protection settings that are required are made during testing and maintenance. Similar routine protection and control system testing and maintenance and associated reviews are conducted for network 33 kV and 11 kV line circuit breaker and recloser control equipment.

6.10.2.3 Power transformers

All power transformers have a regular monthly in-service visual inspection and a biannual minor maintenance service. The biannual service includes visual inspection, routine diagnostic tests, operational checks, and minor work. In general, maintenance work on transformers consists of maintaining oil within acceptable dielectric and acidity limits, and corrosion and oil leak repairs. DGA tests are undertaken on an annual basis to determine transformer health trends. Transformers fitted with on-load tap changers require periodic inspection and servicing based on manufacturers' recommended maximum number of operations and/or minimum number of years between maintenance, whichever is sooner.

Power transformer faults should be diagnosed early enough to remove the unit from service before failure occurs. Full oil refurbishment is initially carried out around 25 years after installation, and approximately every 10 years thereafter. Transformers with high moisture levels at 20 years are evaluated for core drying, where oil results indicate stable winding performance suitable for extending the transformer's life.

Painting is carried out on a regular basis (every 10 to 15 years), depending on site conditions. We plan to paint one unit a year over the next 10 years at an average cost of $5,000 per transformer.

6.10.2.4 Circuit breakers

Circuit breakers have regular in-service inspections and are subject to minor and major maintenance routines. Maintenance on oil circuit breakers should be carried out annually and after it has completed a specified number of fault clearances. Modern vacuum contactors require minor servicing and condition monitoring tests only and at longer intervals. The frequency and scope of service varies for each type, make, and model of circuit breaker, and costs per breaker vary significantly. Older circuit breakers are routinely trip tested to ensure that clearance times are not compromised.

6.10.2.5 Switchyards

Routine maintenance of structures, buswork, and disconnectors is performed when a particular circuit or section of bus is released from service. Buswork and associated hardware is subject to inspection and maintenance, including the checking, tightening, and cleaning of insulators and connections.

For example, during a Transpower outage in Tekapo in 2014, the TEK substation 33 kV and 11 kV structures were extensively inspected, fasteners were tightened and 33 kV insulators and some other components were replaced. Maintenance on other assets was also carried out. Insulator cleaning is undertaken more frequently at zone substations that are subject to atmospheric pollution.

6.10.2.6 Earth mats

Zone substation earth mats are tested annually to verify the integrity of the installation.

6.10.2.7 DC power systems

Substation battery banks and rectifiers are inspected monthly during substation checks, while electronic equipment is virtually maintenance-free and only requires a basic inspection and charger check. The batteries are discharge tested and inspected in detail every year. Battery replacements are carried out every eight years.

6.10.2.8 Buildings and non-electrical assets

Building repairs are ongoing and include interior and exterior painting, and roofing and wall repairs. Substation buildings, bunds, ducts, yard surfaces, and fences are inspected regularly to maintain safety, security, and good 'housekeeping' standards.

6.10.3 Distribution lines and cables

The 2016/17 combined annual Opex budget for network distribution line and cable maintenance (including LV, distribution, and sub-transmission) is $3,643,000 and is split approximately into:

- $224,000 for LV lines and cables
- $3,388,000 for distribution lines and cables
- $31,000 for sub-transmission lines and cables

6.10.3.1 11 kV distribution configurations

The 11 kV distribution lines and cables are typically open-ringed in the CBD and industrial areas, as well as in the denser loaded suburban and rural, areas. LV lines and cables also have interconnection in densely populated urban areas, but are typically short spur lines in other areas.

The open ring system is used for underground cable systems where fault repair time is much longer than for an overhead system. The probability and extent of an underground system fault is much lower than for an overhead system as overhead lines are exposed to risk from severe weather, bird and vegetation interference, and vehicle damage. The risk to underground cables is from inadvertent damage from contractor excavations and low probability severe earthquakes.

Historically, in the days of dry farming and cropping, lightly loaded rural areas were arranged as a single spur overhead line. With load density growing markedly due to dairying and irrigation, rural lines are built or upgraded to be open-ringed, providing alternative supply routes.

6.10.3.2 Line maintenance and replacement

Areas reticulated with predominantly concrete poles from early 1960s to late 1970s have recently been maintained only as required. Over the coming years these areas will be re-inspected. The majority of crossarms and the few hardwood termination and angle poles will need to be replaced. The areas to be targeted are between the Waitaki River and Waimate Township , and between Temuka and Geraldine.

Concrete poles have an estimated life of 60 to 120 years, softwood poles 25 to 50 years, and hardwood poles 40 to 60 years. Very few concrete pole replacements are expected due to age. An age based replacement estimate would indicate that, on average, 260 to 330 poles would need replacing each year. However, adequate maintenance of lines renders the age-based condition assessment inadequate. We use actual condition to inform the replacement of wooden poles.

The risk of premature failure of a softwood pole, due to brown rot or structural degradation, will necessitate inspection prior to its 25th year in service and a high inspection frequency towards end of life. We have, in recent years, discussed and monitored premature failure of softwood poles with other networks that have experienced similar issues.

Due to poor performance and premature cascade failures, softwood poles will no longer be used on the network. A programme to replace existing softwood poles over a number of years has been prioritised as follows:

- conjoint 33 kV and 11 kV lines
- 33 kV lines
- 11 kV lines with heavy conductor
- all others during refurbishment, unless required earlier.

Beyond the planning horizon, analysis indicates that maintenance requirements will increase. A number of 50–60 year old lines with inherently weak conductor (such as 16 Cu, Herring and Mullet ACSR) are near end of expected service life. Some lines have been stretched during many snow and wind events, and have only been repaired before being returned to service each time. The majority of stretched lines will require re-poling to accommodate new conductor. In areas of nil growth, reconductoring of some lines may suffice.

We estimate that approximately 5 km of conductor will need to be replaced each year, at a cost of approximately $350,000 per year, over the planning period and beyond. The replacement rate is expected to increase in the long term.

As an increasing number of hardwood poles needs to be replaced, analysis indicates that line maintenance requirements will rise. To offset the effects of a significant increase, some of the work has been brought forward.

6.10.3.3 Line materials

The refurbishment programme involves replacing the failing original poles with new concrete or hardwood poles fitted with hardwood crossarms. The supply of hardwood crossarms may be limited towards the end of the 10 year planning period and the use of steel, fibreglass, and composite crossarms is currently under evaluation.

From time to time, network lines are subject to extreme conditions such as floods, snow, earthquakes, major wind storms, etc., which results in failure. Failure of a pole line is relatively easy to recover from as spare poles and other fittings can be drawn from normal stock, and repairs can be completed without delay. Often, conductors are not badly damaged and can usually be reused after repairs. Adequate stocks of conductor and accessories are held for most repairs. Although sub-transmission lines are designed and built to withstand most weather events, critical spares for unforeseen circumstances (e.g. car vs pole) are held.

6.10.3.4 Routine patrols and inspections

Overhead lines are patrolled to monitor tree growth

Vegetation control and repair work is scheduled following line patrols. Electrical Hazards from Trees Regulations 2003 require line owners to advise tree owners of their responsibilities for keeping trees away from lines and to provide advice and notification when growth limit and notice limit zones are breached. We have a dedicated database to administer tree management and notification processes.

Fault patrols and repairs are carried out as required

In addition to patrols, a detailed inspection of every line is carried out on a rolling 10 year basis, covering 10% of the route length each year. Where a condition problem is identified, a more in-depth analysis is carried out and a solution implemented. Early line support failure and replacement usually occurs in areas subject to extraordinary winds.

Since 1985, areas predominantly reticulated with hardwood poles installed between 1955 and 1961 have been inspected every 10 years and poles replaced as required. Approximately 10% to 20% of poles are replaced after each inspection. Within the next 10 to 15 years, it is expected that the remainder of the original hardwood poles will be replaced, with the oldest poles remaining being 25 to 30 years old. Crossarms are also renewed during pole replacement.

The regular 10 year inspection and replacement process ensures a level of confidence in the condition of the oldest remaining overhead lines and effectively staggers the capital required for end of life replacement. The aim of inspection is to identify and document all components that may not be able to support design load, and to comply with clearances in NZECP34:2001[50].

Each timber pole is visually inspected from above and below ground to a depth of 500 mm via excavation. The excavation inspects the integrity of the timber in the zone of soil bacteria activity and requires removal of sapwood to measure the remaining healthy heartwood. The diameter of the healthy heartwood is used to determine the remaining service life of the pole, based on the structural design load being met for a further 10 years.

In an attempt to remove human subjectivity, new technology for wood pole assessment is being trialled to establish the best combination of tools available. Although still in infancy, none of the technological solutions evaluated today have instilled confidence in the ability to assess pole condition correctly.

A two coloured tag system is used to identify suspect poles

A standard red tag identifies poles at risk of failure under normal structural loads, requiring replacement within three months of inspection. A standard yellow tag is used to indicate that a pole may not be capable of supporting structural design loads for the next 10 years. Applying a safety factor of two, the yellow tagged poles are replaced within five years of inspection. Poles found to be incapable of supporting structural design loads are replaced in conjunction with red tag poles.

[50] *New Zealand Electrical Code of Practice for Electrical Safe Distances 2001*

6.10.3.5 Underground LV maintenance and replacement

LV distribution boxes

The underground cable network system LV distribution boxes require inspection every five years, with maintenance as required by condition assessment. A relatively high level of urgent reactive maintenance was required during 2009/10 so a special condition survey of all distribution boxes was initiated for an 18 month period. Despite delays due to resourcing issues, the project was completed in early 2013. Once the maintenance follow up is completed, inspections will revert to a five-year cycle.

6.10.4 Distribution substations

The 2016/17 annual maintenance budget for distribution substations is $1,037,000 and covers inspection, assessment, and repairs. Replacement of significant items, such as transformers and RMUs, will be financed from the Capex budget.

6.10.4.1 Distribution substation annual in-service inspections and minor maintenance

Distribution transformers are inspected (and earths tested) every 10 years to comply with Electricity Regulations. Distribution substation earth testing is carried out within a specific earth testing programme with other HV earthed assets. Overhead pole mounted transformer servicing and testing is carried out in conjunction with distribution line inspection and maintenance[51].

A targeted condition assessment project of in-service ground mounted distribution substations of 200 kVA or greater was scheduled in 2010/11. Inspection only projects allow urgent maintenance to be carried out as required.

In 2015, our targeted condition assessment project was changed to become routine in-service inspections and minor maintenance activity for all ground mounted, underground, and two pole distribution substations of 100 kVA or greater. The inspection is spread over a five-year cycle, with approximately 20% of the total population of qualifying substations processed each year.

6.10.4.2 Distribution substation full off-line maintenance

Distribution substations without RMUs are on a 15-year cycle of full off-line maintenance. The routine maintenance is separate from the distribution substation condition assessment described above.

11 kV RMU switches, whether alone or incorporated within a distribution substation, are targeted for full off-line maintenance every five years. One type of oil switch is being replaced on an ad hoc basis as time and resources allow. The whole population is inspected via partial discharge testing (biennially or less) and through oil samples taken during full

[51] Excludes earth testing for distribution substations.

maintenance to ensure oil moisture and dielectric breakdown components are at acceptable levels, and the oil switches remain safe and reliable.

6.10.4.3 Distribution substation transformers

Transformers are replaced when a failure occurs or is likely to occur within 10 years. It is more economical to replace distribution transformers than to refurbish onsite. Failures generally result from lightning strikes, cable termination failures, and car accidents. Faulty transformers can usually be replaced within four to eight hours from the spares stock held at our Washdyke yard.

Maximum demand indicators fitted to the larger ground mounted transformers indicate that few have been allowed to operate for long past the nameplate rating. Therefore, the expected life of a distribution transformer is 55 years.

6.10.5 LV lines and cables

The 2016/17 annual maintenance budget for LV lines and cables is $224,000.[52]

6.10.6 SCADA, communications, and ripple plants

The 2016/17 maintenance budget for SCADA , communications, and ripple plants is $186,000.

6.10.6.1 SCADA system maintenance

In 2013, the present SCADA system Master Station hardware platform was replaced as it exceeded its economic life. The hardware replacements were chosen to meet the requirements of future software upgrades.

The Master Station software upgrade includes expansion of the present SCADA system database and software capacity to cater for the increasing number of zone substations, and monitored and controlled points from the communications upgrade project. The new SCADA will include a whole network view, thereby supporting efficiencies in the preparation, updating, and operational use of our network switching diagrams.

The integrity of the SCADA hardware and software systems is of paramount importance to the ongoing management and safety of the network

6.10.6.2 DC power supply, battery, and rectifier maintenance

Our maintenance programme includes routine replacements of DC power supply batteries and chargers and minor systems.

6.10.6.3 Zone substation security and fire alarm systems

The legacy security and fire alarm systems are past economic life and are being replaced by new systems. We expect to complete the replacement programme by the end of the

[52] Does not include renewal or upgrade expenditure—this is covered by the Capex budget.

2016/17 financial year. The supplier of the new systems has been contracted to carry out routine maintenance on the equipment.

6.10.6.4 Communication systems

We are progressively introducing a new digital GHz frequency radio system for SCADA system communications.

Communications are installed as zone substations are added or upgraded on our network. Modern substations contain microprocessor based protection and control equipment that uses the DNP3[53] protocol and requires modern communications (for more detail, please see Chapter 3—NETWORK ASSETS and Chapter 5—NETWORK DEVELOPMENT PLANNING).

The legacy UHF analogue radio system has reached its end of life as determined by age, reduced manufacturer support, and obsolescence of legacy technology being replaced by modern microprocessor controlled technology. The legacy base station and repeater require regular inspection and service. Inspections, as far as possible, are non-intrusive and no adjustments are made until items are out of tolerance, or performance is affected. Antenna support structures are inspected every two to three years.

Network failures are normally random in nature and result from various causes such as drift in component settings, lightning strike, wind on antennae, etc. The 2013 severe winter conditions highlighted the importance of response to communications faults and the maintenance of battery backup systems during loss of supply, with helicopter access to install supplementary battery support as a fall back.

Communications equipment generally has a shorter life expectancy than heavy electrical assets. Typically, electronic equipment reached technical obsolescence in 5 to 10 years although equipment assets can be supported in service for 10 to 15 years. A number of analogue radio systems will require replacement in the next two years.

6.10.6.6 Communications and SCADA system equipment room

In 2009, we commissioned an independent consultant's report to advise on the state of and recommend an upgrade path for our existing communications and SCADA system equipment room. The report, completed in 2009, confirmed the need to upgrade SCADA in order to improve its reliability and efficiency. The report made a number of recommendations covering the many systems and equipment in the room. The consultant estimated the cost of upgrading the room and various equipment and systems to between $150,000 and $205,000, depending on the options chosen.

Following the report, we decided to review our whole SCADA Master Station and communications set up. In order to maintain adequate system reliability, the SCADA Master Station has been upgraded and relocated to a new control room facility. The relocation of the system will also allow the equipment room to be upgraded.

[53] Distributed Network Protocol—a set of communications protocols used between components in process automation systems. *Source: Wikipedia*

6.10.6.7 Ripple load control plant

We are in the process of updating our ripple injection system. Old rotary injection installations are being replaced with new solid state injection plant. The new injection plant requires minimum maintenance, and maintenance expenditure on ripple load control plant will diminish as older assets are decommissioned. A breakdown of the replacement programmes is included in Section 5.9—Capability to deliver.

6.10.7 Vegetation management

An increasing amount of work is required to manage vegetation that encroaches on, and threatens the safety and reliability of, our lines and other overhead assets. The growth of trees and other vegetation appears to have increased in recent years, possibly due to increased availability of water through irrigation. Wetter ground conditions also increase the risk of trees falling from strong winds.

6.10.7.1 Tree cutting programmes

We conduct an active programme of tree cutting to keep trees away from lines and where possible from the routes of new lines and extensions. We employ two full-time vegetation officers to manage and coordinate the programme. The majority of the actual cutting is undertaken by contracted arborists.

A new vegetation management database has been set up to record and assist with the management of vegetation control work. The database tool allows tree maintenance to be correlated with SAIDI events attributable to ‘tree causes’, while enabling more accurate budgeting, planning, and management of vegetation control resources. As a result of the severe wind storms of 2013, a successful programme of removing trees within falling distance of 33 kV sub-transmission lines was undertaken with the support of the property owners concerned.

6.11 Non-network asset maintenance and renewal

Non-network assets are those defined by the Commerce Commission as being related to the provision of electricity line service, but not directly used to provide line service. The information disclosure requirements provide a list of non-network assets used by us and include a description of use, and maintenance and renewal policies. We are currently developing policies for specific areas of asset management, including vehicle maintenance and replacement, ICT asset renewal, and property maintenance.

6.11.1 Motor vehicles

Vehicles are used for a variety of roles depending on the department. Our vehicle fleet includes four wheel drive utility vehicles and station wagons. At present, vehicle maintenance and renewal is managed using a spreadsheet based algorithm that records distance travelled, vehicle age, and licensing requirements. All vehicles in our fleet are owned by us. The fleet is currently managed by our General Manager—Safety and Risk, and vehicles are replaced every four years on average.

6.11.2 Office buildings

A building that houses a network asset is considered to be a network asset in its own right. Buildings not classified as network assets include the four buildings used to house our engineers, controllers, and corporate staff, and are all located at our Washdyke depot.

The office buildings occupied by us and NETcon are currently managed by our Corporate Services, which conducts building warrant of fitness checks once a month. Safety issues are addressed on notification. Buildings and facilities are upgraded in line with our strategic requirements, ensuring that our facilities are fit for purpose. The NETcon building was upgraded in 2014/15 in line with this approach.

6.11.3 Information systems

For a description of computer and communication systems specific to our electrical power network (e.g. SCADA system, ripple load control, etc., please refer to Section 2.7.1.1—Information technology for asset management).

ICT assets are managed by our IT Services Manager according to life cycle principles of procurement, maintenance, and disposal, depending on user requirements and the most beneficial solution. ICT software is regularly updated and we play licensing fees for software packages (including Microsoft products) in return for upgrades, support, and maintenance. We hold service level agreements with our financial package provider and with Fujitsu for general ICT requirements. Day-to-day ICT needs are met by our IT Services Team.

At present, information management is a high priority area of our business. We are investing in staff, knowledge based consultants, and software to find holistic solutions to our information needs. Spending on information management is expected to reduce once service level targets are met.

6.11.4 Business equipment

Maintenance and renewal of non-ICT office equipment (e.g. furniture, appliances, etc.) is managed by our Corporate Services. With the exception of electrical equipment, which is tested and tagged on an annual basis, non-network assets are maintained on a case-by-case basis. Non-network asset purchases of over $500 are approved by department managers and/or our Group Manager—Corporate Services.

6.12 Maintenance (Opex) budget projections

Table 6.14 lists the projected maintenance expenditure by asset class for 2016/17 in nominal (non-adjusted) dollars. Nominal dollars are used to highlight the fact that we are reducing Opex in real terms by an amount equivalent to inflation each year and that Opex is constant in nominal terms till at least 2022/23.

The maintenance expenditure projections are calculated under the following assumptions.

- Continued maintenance expenditure over the period due to ongoing condition assessment activity revealing in detail the extent of repair and maintenance requirements.

- Introduction of centralised control in 2009, with fault work contracted to NETcon, with consequential addition of an estimated $1 million to the annual Opex budget for distribution lines and cables.
- Maintenance expenditure budget to be held constant in nominal dollars from 2015/16 to 2022/23 (i.e. annual reduction of budget in real terms at CPI rate).
- Work to eliminate the most urgent cases from the 15 years of deferred maintenance prior to 2008.
- Reduction in overall maintenance required as new lower maintenance assets are introduced onto the network as a result of upgrades and renewals.
- Limitations of NETcon's resource to undertake both maintenance and capital work.
- Limitations on network assets for maintenance intervention imposed by Operations (outages and switching).

The assumptions of reducing growth in maintenance expenditure may not eventuate should the following occur.

- Complexity and size of some of the new assets increase, requiring higher levels of technical attention during routine and reactive maintenance.
- Numbers of site and assets increase as the network load and load density grow.
- Higher levels of routine maintenance activity per site as condition assessment requirements increase and techniques for measuring condition improve.
- Existing plant that does not require urgent maintenance moves from low to high need for maintenance as it reaches end of life (e.g. Opex refurbishments that do not fall in the renewal or upgrade Capex categories).

6.13 Renewal and upsizing (Capex) budget projections

There are six categories of network asset life cycle maintenance expenditure:

- operations
- maintenance
- renewal and refurbishment
- upsizing (or upgrading)
- extensions
- retirement.

With the exception of renewal and major refurbishment, which is covered under asset replacement Capex, all of the six categories are usually budgeted for as Opex. The expenditure planned for asset replacement and renewal is detailed by project (along with other Capex expenditure) in Chapter 5—NETWORK DEVELOPMENT PLANNING. Table 6.15 summarises the asset replacement and renewal budget by asset category for the 2016–2026 period in real (constant) dollars.

6.13.1 Innovations to defer renewal

The need to innovate prior to committing to large Capex projects is an integral part of our network planning. An example of innovation in planning is the decision to install smart meters on our network over the next few years. We may use smart meters to limit capital expenditure through load control from ABY and TIM substations, thereby reducing the need for renewal of associated ripple load control relays. Once smart meters are rolled out, the effectiveness of load control at these and other sites will be evaluated.

Asset category	Forecast (in $'000)									
	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
LV lines and cables	224	224	224	224	224	224	224	229	233	238
Distribution substations	1,037	1,037	1,037	1,037	1,037	1,037	1,037	1,058	1,079	1,100
Distribution lines and cables	3,388	3,388	3,388	3,388	3,388	3,388	3,388	3,455	3,525	3,595
Zone substations	482	482	482	482	482	482	482	491	501	511
Sub-transmission lines and cables	31	31	31	31	31	31	31	32	32	33
SCADA and radio	186	186	186	186	186	186	186	190	194	198
Unspecified	1	1	1	1	1	1	1	1	1	1
TOTAL	**5,349**	**5,349**	**5,349**	**5,349**	**5,349**	**5,349**	**5,349**	**5,456**	**5,565**	**5,676**

Table 6.14 Maintenance expenditure by asset category (in nominal dollars)

Project category	Forecast (in $'000)									
	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Sub-transmission, distribution, and LV lines and cables	4,341	2,705	3,231	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Distribution substations, including transformer, regulators, ring main units, and so on	820	822	822	782	782	692	630	570	570	570
Zone substations	650	2,450	300	300	150	350	200	200	200	200
SCADA, comms, and load control plants	860	500	1,000	505	550	550	550	550	550	550
Total asset replacement and renewal projects expenditure	**6,671**	**6,477**	**5,353**	**3,187**	**3,082**	**3,192**	**2,980**	**2,920**	**2,920**	**2,920**

Table 6.15 Asset renewal and refurbishment budgets 2016–26 (in constant dollars)

7. RISK MANAGEMENT

7.1 Introduction

Chapter 7 outlines the risk management approach we employ for managing our network assets and activities. All risk management plans form part of our integrated Safety Management System (SMS), which is described in Figure 7.1.

With the implementation of an extensive Risk Management Policy we are reviewing and strengthening our comprehensive risk management register to provide risk management consistency across all facets of our company, and to support and standardise our risk assessment and mitigation management. Further information on our Risk Management Policy development can be found in Section 5.10.2—Network Development Plan prioritisation process.

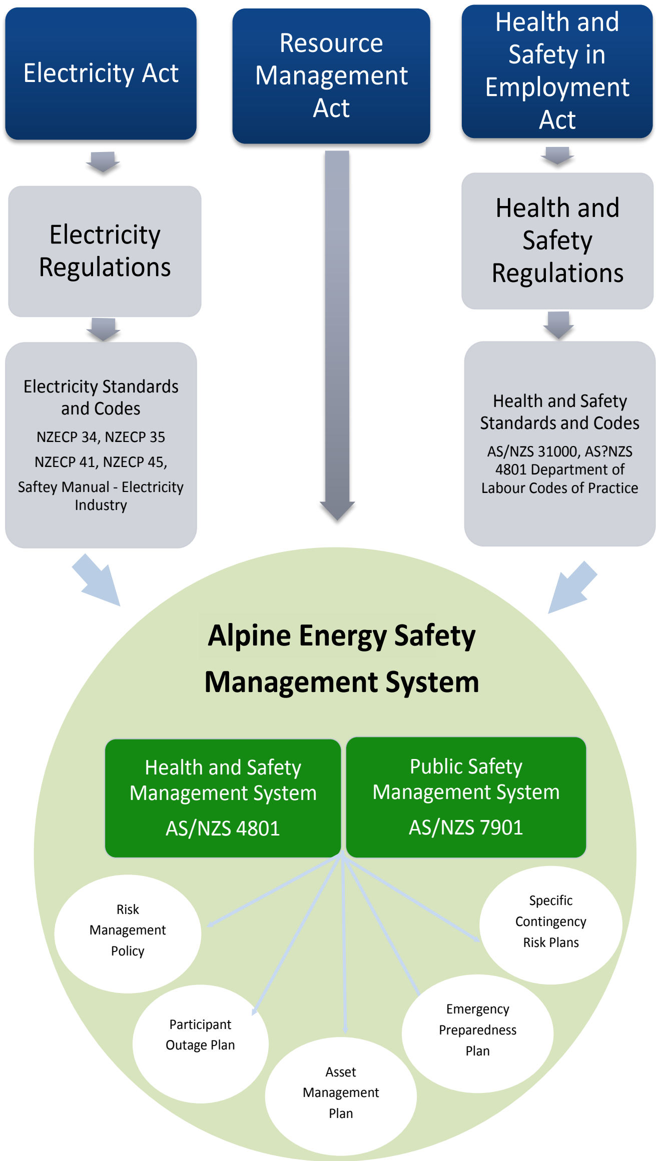

Figure 7.1 Safety management system framework

7.2 Safety management system

Our SMS consists of the Health and Safety Management System and Public Safety Management System.

Our Public Safety Management System is subject to annual external audit to ensure compliance with the requirements of:

- NZS7901:2014 Electricity and Gas Industries—Safety Management Systems for Public Safety
- AS/NZS 4801:2001 Occupational Health and Safety Management Systems.

Our integrated Safety Management System also feeds into our:

- Asset Management Plan
- Emergency Preparedness Plan
- Participant Outage Plan
- Civil Defence Emergency Management
- various specific contingency plans.

7.2.1 Public Safety Management System

The Electricity (Safety) Regulations 2010 require all electricity distribution companies to produce a Public Safety Management System. The purpose is to prevent serious harm to members of the public or significant damage to property from network assets and/or asset operation. Risk management activities referred to in this AMP are consistent with the requirements of the Public Safety Management System.

There is a statutory requirement to be audited to NZS 7901:2014 Electricity and Gas Industries—Safety Management Systems for Public Safety by an accredited audit body. The audits commenced in April 2012 and are carried out annually.

For further information, please refer to our Public Safety Management document.

7.2.1.1 Public education

We reduce a number of external risks through public education. By placing regular safety messages in the media, we communicate to the public the consequences of their actions in relations to electricity and electrical assets. Communication through media helps us to create awareness in the community regarding potential hazards, and reminds the public to contact us when a hazard is perceived. Figure 7.2 provides an example of our communication through print media.

For further details, please refer to our Public Safety Awareness and Education Policy.

Figure 7.2 An example of our public safety message in print media

7.2.1.2 Security of ground mounted assets

Our ground mounted assets are protected from public intrusion by the standard practice of locking the external body equipment and by sometimes placing the assets in secure compounds.

For T1 DB distribution boxes, distribution boxes, and link boxes, we are implementing tamper-proof uniquely keyed fasteners to replace socket headed cap screws.

We are in the process of a major overhaul of out lock hardware to a single unique hierarchical keyed lock system.

7.2.2 Health and Safety Management System

The Health and Safety in Employment Act 1992 requires all businesses to have an occupational health and safety management system in place. The purpose of the system is to prevent serious harm to employees, contractors, and the general public or significant damage to property arising out of our work activities.

For further details, please see our Health and Safety Management System document.

7.3 Emergency response and contingency planning

We recognise that the local economy depends on a secure and reliable supply of electricity, and that a catastrophic event such as an earthquake, landslide, tsunami, flood, wind and snow storms, and terminal failure of key assets can have significant impact on both the network and the local economy.

We have developed emergency response plans for dealing with widespread abnormal situations created by either asset failure or catastrophic natural events. All emergency response plans are regularly reviewed to ensure that unique risks arising from emergency response have been identified.

Mutual Assistance Agreements have been signed with peer electricity distribution networks. These agreements were successfully implemented during the Canterbury earthquakes of September 2010 and February 2011.

For further details, please see our Emergency Preparedness Plan.

7.3.1 Business continuity planning

Regular electronic backups of mission critical records for retailer billing and consumer identification are carried out. The backup copies are securely stored offsite.

We are looking at establishing a more encompassing Business Continuity Plan that will incorporate our SCADA, GIS, and other essential databases.

7.3.2 Emergency Preparedness Plan

Our Emergency Preparedness Plan complies with the requirements *of NZS 7901:2014 and AS/NZS 4801:2001* and is regularly reviewed after each critical event, and on an annual basis.

The plan is distributed to our staff as part of our Health and Safety Management System, instructing them of the procedures to follow for emergency events, including:

- Civil Defence Emergencies
- major accidents
- fire and evacuation of site
- earthquake
- extreme climate events
- threats and conflict situations
- hazardous or toxic substances (oil spillage or SF_6 release)
- pandemic.

7.3.3 Emergency communications

Our emphasis on appropriate emergency communication ensures information is provided to stakeholders and the public in a proactive manner. Our communication responsibilities are:

- Chief Executive Officer—media, stakeholders, EDBs, and Transpower
- Group Manager— Corporate Services—general public
- General Manager–Safety and Risk—Police, Civil Defence, local councils and other local authorities, and large customers.

Responsibilities for communications are detailed in Section 4.2 of the Participant Outage Plan.

7.3.3.1 Telephone Video Data and network status report

The public can keep up-to-date on the location of outages and resolution by logging on to the 'Network status' section of our website. Consumers can also subscribe to Telephone Video Data (TVD), which will send them a notification regarding outages in areas that they indicate they want information for. The public can also phone us for information and listen to the radio.

7.3.4 Participant Outage Plan

The Electricity Governance (Security of Supply) Amendment Regulations 2009 require all specified EDBs to prepare and publish a Participant Outage Plan (POP) for audit and approval by the Electricity Authority.

The Plan is required to conform with the requirements set out in the Electricity Authority's Security of Supply Outage Plan (current version October 2009), and details how electricity distributors will manage either a total outage or rolling outages of up to 25% of normal load if there is a national or regional electricity shortage.

Our most recent Participant Outage Plan has been submitted to the Electricity Authority for audit and approved. A copy of the current Plan can be found on our website.

7.3.5 Specific contingency plans

Specific contingency plans for the restoration of supply to essential services and to individual major industrial and commercial consumers exist to complement and supplement the Participant Outage Plan. For example, if we lost both 110 kV TIM–TMK circuits that supply our Temuka 33 kV, we have a specific plan developed jointly with Transpower to ensure electrical supply continuity to the Fonterra Clandeboye dairy factory.

7.3.6 Civil Defence Emergency management

In the event of a Civil Defence Emergency, nominated staff members are sent to man the local district council's Civil Defence Emergency Operations Centre. A dedicated radio telephone link is installed in the Timaru District Council's Emergency Operations Centre for direct communication with our control room.

The Canterbury Lifelines Utilities Group[54] promotes resilience to risks, and develops contingency measures for Civil Defence Emergencies arising from natural disasters.

As a lifeline utility, we participate in the development of both regional and Civil Defence Emergency Management plans, and provide technical advice to local authorities and other lifeline utilities as requested.

We participate fully in Civil Defence's regional exercises such as 'Pandora', 'Olaf', and 'Ripahapa'. Lessons learnt from these exercises are used to enhance our current emergency response planning.

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[54] We were a founding member of the South Canterbury Lifelines Group, which amalgamated with the Canterbury Lifelines Utilities Group.

7.4 Risk management planning for network assets

All our activities involve risk. We manage risks by anticipating, understanding, and deciding whether or not to modify the activity to mitigate the risk. The purpose of risk assessment is to provide empirical knowledge and analysis to make informed decisions on the treatment and method of resolution of particular risks.

We will accept risk in order to achieve or exceed our objectives, provided that the risks are understood and appropriate mitigation is in place to ensure the risk is within our bounds of acceptable risk.

We assess and treat risk as part of asset management. For confidence and consistency, we undertake our risk management activities in accordance with our Risk Management Policy. The Policy was approved by the Board of Directors, and the CEO, effective from 15 October 2015. Our Risk Management Policy is consistent with the international standard *AS/NZS/ISO 31000:2009 Risk Management—Principles and Guidelines*, and was peer reviewed by experts in risk management.

We aim to integrate high quality risk management activities with all critical processes so that we are able to recognise and respond to risk before events occur. Responsibility for managing risks rests with all staff and the Board of Directors, as described in Table 7.1. Accountability for risk management includes ensuring that the necessary controls to modify the risks and control assurance activities are in place and are effective at all times.

Title	Responsibility
Board of Directors	The Board is responsible for approving of the Risk Management Policy, determining our risk criteria, ensuring the Policy can be implemented, monitoring ‘very high’ risks (with assistance from the Audit and Risk Committee), the correct functioning of critical controls, and effective implementation of the Policy.
Chief Executive Officer (CEO)	The CEO is accountable to the Board for approving our risk management standards, and ensuring the standards are applied consistently to all planning and decision making.
Group Manager—Corporate Services	The GM—Corporate Services is accountable for: • developing and maintaining our risk management standards • providing technical risk management support, and associated tools and practices • reporting to the Audit and Risk Committee (excluding Health and Safety matters).
Executive Management Team (EMT)	The EMT is responsible for monitoring and reviewing our risk management activities and performance, including consistency with AS/NZS ISO 3300 and our guidelines and procedures.

Title	Responsibility
Managers and team leaders	Managers and team leader are responsible for applying our standards to the assessment and treatment of risk in their business areas, and for monitoring the correct functioning and ongoing applicability of controls.
General Manager—Safety and Risk	The GM—Safety and Risk is accountable for: • developing and maintaining our Health and Safety risk management standards • providing technical risk management support, and associated tools and practices.
All personnel	All personnel are accountable for fulfilling their specific risk management functions.

Table 7.1 Risk management responsibility and accountability

Assurance of good governance will be achieved through the regular measurement, reporting, and communication of our risk management performance by ensuring that the resources, delegations, and organisational arrangements are in place. We are in the process of establishing an assurance programme to help us monitor our progress.

With our Risk Management Policy aligned to AS/NZS/ISO 31000:2009 Risk Management—Principles and Guidelines, the risk management process involves risk

- identification
- analysis
- evaluation
- treatment
- monitoring and review.

Our network is exposed to a range of internal and external influences that can have an impact on our business objectives. These influences provide a context for risk identification. The nature of electricity networks means that the network may be exposed to events that push the integrity of the components past design capability. The subsequent failures have to be reviewed to determine the impact on the network, consumer supply, and our ability to limit the disruption through risk mitigation.

A risk management study based in AS/NZ 4360:2004—Risk Management, and the EEA's Guidelines for Security of Supply in NZ Electricity Networks, was undertaken for sub-transmission and zone substation assets in the 2005/06 financial year. The findings are presented in Table 7.5 and Table 7.6.

The EEA has since published a revised Guide for Security of Supply August 2013. With our Risk Management Policy in place, a full review of the risk management study will need to be undertaken in the 2016/17 financial year.

The appropriate plan of action in response to an identified risk may include capital development, maintenance or operational enhancement, business planning or training, and contingency planning. Our maintenance programme includes routine inspections to ascertain asset condition and regulatory compliance. Our policies rank public and environmental safety as top priority.

7.4.1 Risk identification

Identification of network risk is an iterative process. While our process is well developed, new techniques for predictive condition support and proactive risk management are being developed based on long-life assets (for example, the recent release of the new EEA guide—Asset Health Indicators).

Consequences of risk on our network can be grouped into the following categories:

- reputation
- natural environment
- compliance
- financial
- asset utilisation
- reliability of supply
- security of supply

7.4.1.1 Environmental risks

We are committed to operating in a manner that is environmentally sustainable.

There are many events outside of our control that threaten to interrupt the operation of our distribution network (e.g. floods, high winds, lightning, snow, earthquake tsunami, fire, etc.). To counter the effects of such events on the environment and the public (e.g. chlorofluorocarbon gas emissions, oil spills, arc flash exposure, failure of line supports, etc.), we place great importance on the selection and installation of our network components.

7.4.1.2 External risk

Risk to the network can be introduced by the public through:

- inadequate control of trees adjacent to overhead lines
- operating plant or stockpiling material without adequate clearance from overhead lines
- lighting fires adjacent to overhead lines
- moving irrigators under overhead lines
- undermining pole foundations
- colliding with our assets (e.g. car vs pole)
- illegal access into authorised areas
- leaving electric fence wire or other conductive material where wind or birds may carry it up into overhead lines.

7.4.2 Risk analysis

Risk analysis is used to determine the most effective means of risk treatment. A number of dimensions must be satisfied to meet our objectives of managing our assets in a safe, reliable, and cost-effective manner.

We have undertaken a qualitative assessment of risk that we face to determine its ranking. Table 7.2 lists the qualitative measures of likelihood we use in our risk assessment.

Level	Descriptor	Description	Indicative return period
5	Certain	Will occur frequently	Once or more per annum
4	Likely	Will occur infrequently	Once in 1–4 years
3	Possible	Might occur	Once in 4–10 years
2	Unlikely	Will seldom occur	Once in 10–50 years
1	Rare	Theoretically possible but unlikely to occur	Once in 50–100 years or less

Table 7.2 Measure of risk likelihood

Table 7.3 describes the qualitative measures of consequence or impact that we use in our risk assessment.

Consequence level	Insignificant	Minor	Moderate	Severe	Extreme
Reputation	No interest outside Alpine Energy	Local papers, brief criticism, little controversy	Local and regional media, criticism not widespread, brief	Regional and national criticism for more than two days	Regional and national media criticism, highly adverse, sustained for a week or more
Natural environment	Little or no impact	Small scale contained event, short-term impact, managed internally	Event restricted to one locality, localised impact on habitat/environment; some external support required	External support required to contain, notifiable, potential long-term impacts	Massive environmental contamination damage to endangered flora/fauna

Consequence level	Insignificant	Minor	Moderate	Severe	Extreme
Compliance	No breach	Breach of legislation, code of practice, or industry standard; no applicable penalties	Financial penalty of up to $10,000	Prison term of less than two years and/or financial penalty of up to $100,000	Prison term of more than two years and/or financial penalty of over $100,000
Financial	Potential loss or cost of up to $20,000	Potential loss or cost of $20,001–$100,000	Potential loss or cost of $100,001–$1 million	Potential loss or cost of $1 million–$5 million	Potential loss or cost of > $5 million
Asset utilisation		Network asset (to the value of under $100,000) underutilised or stranded	Network asset (to the value of $100,000–$1 million) underutilised or stranded	Network assets (to the value of $1 million–$5 million) underutilised or stranded	Network assets (to the value of over $5 million) underutilised or stranded
Reliability of supply	Unplanned outages (Class C): <0.02 SAIDI mins or <40 ICP interruptions per event	Unplanned outages (Class C): 0.04<>0.02 SAIDI mins or 100<>40 ICP interruptions per event	Unplanned outages (Class C): 10.06<>0.04 SAIDI mins or 1000<>100 ICP interruptions per event	Unplanned outages (Class C): 1<>0.06 SAIDI mins or 1,500<>1,000 ICP interruptions per event	Unplanned outages (Class C): >1 SAIDI mins or >1,500 ICP interruptions per event
Security of supply	Non-compliance on loads below 0.2 MVA	Non-compliance on loads 1<>0.2 MVA or inability to supply new load within three months	Non-compliance on loads >1 MVA or inability to supply new load within 12 months	Non-compliance on loads >9 MVA or inability to supply new load within 24 months	Non-compliance. Causes negative growth or inability to supply new load within 48 months

Table 7.3 Measure of risk consequence

Figure 7.3 combines the qualitative assessment of consequence and likelihood to provide a level of risk matrix.

Likelihood	Insignificant	Minor	Moderate	Severe	Extreme
Certain	Low	Medium	High	Very High	Very High
Likely	Low	Medium	High	High	Very High
Possible	Low	Medium	High	High	Very High
Unlikely	Low	Low	Medium	Medium	High
Rare	Low	Low	Low	Medium	High

Consequence

Figure 7.3 Risk matrix

Based on the risk score, specific response and reporting requirements are determined. The requirements are described in Table 7.4.

Level of risk	Urgency for implementation of treatment	Authority for continued tolerance of risk	Reporting
Very high	Immediate corrective action to rectify or mitigate the impact of the identified risk to be implemented ASAP under GM—Network's supervision	CEO	Advise GM—Network immediately, and the GM to advise CEO immediately after receiving advice and to include in next reporting cycle. CEO to advise Risk and Audit Committee (Board) as appropriate and to include in next reporting cycle.
High	Action plan to be developed within [x][55] days of the identification to GM—Network (or such other period that is practical in the circumstances).	GM—Network	Advise GM—Network within 24 hours of identification, and the GM to advise CEO as soon as practicable after receiving advice and to include in next reporting cycle.
Medium	Action plan (if necessary) to be developed within [x] months of identification to the GM—Network (or such	Managers	Advise GM—Network within five days of identification. If necessary, include in next reporting

[55] Where [x] days or months, the number is determined by the GM—Network to suit the circumstance.

Level of risk	Urgency for implementation of treatment	Authority for continued tolerance of risk	Reporting
	other period that is practical or necessary in the circumstances).		cycle.
Low	Treat in line with other priorities. Ongoing monitoring.	Manager	Advise Manager or, if appropriate, relevant committee or group (e.g. Planning Committee).

Table 7.4 Response by risk level

Risk analysis evaluates the factors that influence the consequences and likelihood of an event, as well as the effectiveness of existing controls and management strategies.

Quantitative analysis is used where specific performance measures are in place, e.g. oil sample testing of zone substation transformers. The testing provides a review of compounds in the oil sample to determine health and position on the age curve based on known operating history. The quantitative approach allows us to manage assets with the highest event consequence cost throughout expected service life.

Our distribution network is built in a hierarchical structure with Transpower substations providing supply points for 33 kV sub-transmission to zone substation assets (plus 110 kV at BPD). The zone substations have multiple feeders that connect the 11 kV distribution lines. Distribution lines traverse the region and support 11 kV assets and distribution level transformers, which break down into the LV networks and some 30,000 consumer connection points.

Failure of a hierarchy asset at the Transpower connection level carries the serious consequence of disrupting a large number of consumers. Fortunately, such a failure is a very low probability event.

Please note that the levels of risk summarised in Table 7.4 and Table 7.5 are based on the AS/NZS 4360:2004 guidelines. The risk assessments will be updated in the 2016–17 financial year using the risk management framework described in our Risk Management Policy.

Identified Risk categories for Substations																
Site	Loss of SubTransformer	Protection mal-operation	Bus Fault	CB failure	Switchboard failure	Building failure	Vandalism	Operating error	Line Hardware equipment failure	Backup protection operation	Snow	Wind	Flood	Earthquake	Incoming Supply	Ripple Plant
Timaru 11/33 kV	M	M	M	L	-	L	M	M	L	L	L	M	L	M	L	H
Grasmere St 11 kV	-	L	L	L	L	L	L	H	-	H	L	L	L	L	L	-
Hunt St 11 kV	-	M	M	M	M	M	L	M	-	M	L	L	L	L	L	-
North St 11 kV	-	L	L	L	L	L	L	M	-	M	L	L	L	L	L	-
Pleasant Point 33/11 kV	H	M	M	L	M	L	L	L	-	M	L	L	M	L	H	-
Pareora 33/11 kV	M	M	L	M	M	L	L	M	L	L	L	L	L	M	H	-
Temuka 33/11 kV	M	M	M	L	M	L	L	M	L	M	L	L	M	M	M	M
Geraldine 33/11 kV	H	M	M	L	M	L	L	L	-	M	H	L	M	M	H	-
Rangitata 33/11 kV	M	M	L	L	L	L	L	L	L	L	M	L	L	L	M	-
Clandeboye 1 33/11 kV	M	H	M	L	M	L	L	H	L	H	L	L	L	H	M	-
Clandeboye 2 33/11kV	M	H	M	L	M	L	L	H	L	H	L	L	L	H	M	-
Studholme 11 kV	-	-	M	L	M	L	L	M	-	M	L	L	H	L	L	M
Bell’s Pond 110/11 kV	H	M	M	L	M	L	L	L	L	L	L	L	L	L	L	M
Albury 11/33 kV	H	M	M	L	M	L	L	L	L	M	M	M	L	M	H	H
Fairlie 33/11 kV	H	M	M	L	M	L	L	L	M	M	M	L	L	M	H	-
Tekapo 33/11 kV	H	M	M	L	M	L	L	L	M	M	H	L	M	M	H	H
Glentanner 33/11 kV	H	M	-	L	-	-	L	L	L	M	H	H	L	H	H	-
Unwin Hutt 33/11 kV	H	M	-	L	-	-	L	L	L	M	H	H	L	H	H	-
Balmoral 11/22 kV	H	M	-	L	-	-	L	L	L	M	H	H	L	H	H	-
Haldon / Lilybank 11/22 kV	H	M	-	L	-	-	L	L	L	M	H	H	L	H	H	-
Twizel 33/11 kV	H	M	M	L	M	L	L	L	L	M	H	H	L	H	H	H

Table 7.5 Substation risk level

Asset Category	Cable joint failure	Cable termination failure	Cable unsupported and failing	Cable over rated	Cable thermal runaway	Earthquake	Cable strike	Operating Error	Ferroresonance	Foundation undermined	Insufficient ground clearance	Pole rot	Cross arm failure	Insulator failure	Stay wire failure	Tree contact	Contractor/land owner accidental contact	Vehicle	Wildlife	Overload	Snow loading	Wind loading	HV Line Contact	Lightning	Rust	Flooding	Short circuit	Vandalism	Public access
33 kV Cables	H	H	H	M	M	H	H	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11 kV Cables	L	L	L	M	M	H	H	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtransmission lines	-	-	-	-	-	H	-	L	-	L	M	M	L	L	L	M	L	-	-	-	L	L	-	-	-	-	-	-	-
Distributions lines	-	-	-	-	-	M	-	L	-	L	L	L	L	L	L	M	M	M	L	L	M	M	-	-	-	-	-	-	-
11 kV Distribution Cables	L	L	L	M	M	H	M	M	M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Transformers (OH	-	-	-	-	-	M	-	-	-	-	-	-	-	-	-	-	-	-	-	M	L	L	-	L	L	-	L	-	-
Distribution Transformers (GM	-	-	-	-	-	H	-	-	-	-	-	-	-	-	-	-	-	-	-	M	-	-	-	L	L	L	L	L	L
Voltage Regulators	-	-	-	-	-	H	-	-	-	-	-	-	-	-	-	-	-	-	-	L	-	-	-	M	L	-	L	L	L
Reclosers (pole top)	-	-	-	-	-	M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	L	M	-	M	L	-	-	-	-
Ring Main Units	-	-	-	-	-	M	-	M	-	-	-	-	-	-	-	-	-	M	-	-	-	-	-	L	L	L	L	L	M
LV Overhead Lines	-	-	-	-	-	L	-	-	-	L	L	L	L	L	L	M	L	L	L	L	M	M	M	-	-	-	-	-	-
LV Underground cables	L	L	L	L	L	L	L	L	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LV Distribution Boxes	-	-	-	-	-	L	-	-	-	-	-	-	-	-	-	-	-	M	-	L	-	-	-	-	L	L	M	M	M

Table 7.6 Risk level by asset category

7.4.3 Network asset risks

Further review of the outcomes from Table 7.4 identifies the loss of a power transformer at a single transformer zone substation as a high risk. Our approach of maintaining critical spares lowers the risk to a moderate level. Other procedures such as regular oil sampling and major maintenance when a transformer is moved from one location to another further lower the likelihood of asset failure.

With growing demand on the network, some substation sites do not have N-1 security at all times. Accordingly, we regularly review our contingency plans for transformer failure and replacement.

Bus bar faults and circuit breaker failures are classified as moderate risk and can be tolerated with provision of existing spares inventory.

To date, instances of vandalism have been low. The installation of security alarms, perimeter fences, and locks keep risk at a low level.

7.4.3.1 Mobile generator and substation

In 2014 we commissioned two projects.

- A mobile generator set (AMG) made up of two 900 kVA machines able to base load at 500 kW each or 1 MW in total. The machines can be used at 11 kV or 400 V to allow maintenance of distribution substations or provide small community back-up.
- A mobile substation (AMS) that steps 33 kV to 11 kV with a 9 MVA rating. We are preparing all of our single transformer substations so that the AMS can be installed in parallel to allow the release of the substation for maintenance.

7.4.3.2 Risk to substation assets

The risk from line hardware at substations is acceptable due to regular maintenance and surveillance systems that are in place. Provided these are maintained, the risk levels are unlikely to change.

There is a high risk at HNT, CD1 and CD2 substations should the protection fail to operate and clear the faulted zone. The backup protection will isolate a large area of consumers by impacting their supply. Isolation protects other feeders supplied from the common bus bar and cannot be improved without major work.

To prevent the level of risk at HNT from increasing, we regularly test the remaining legacy protection schemes and conduct peer reviews of protection setting alterations. An upgrade of the electromechanical relays to microprocessor controller assets at end of life will reduce coordination and discrimination problems, lowering the level of risk at the substation.

Procedures for operating at CD1 and CD2 substations require regular enforcement, so as to prevent configuring the system to expose risks of backup protection operation.

Previously there was a moderate risk to the dual fibre optic cables' primary protection at GRM, HNT, and NST due to improper excavation. Recent upgrades cover circumstances where the cables are severed—the protection prevents circuits from tripping. The two new sub-transmission cables from TIM GXP to NST substation mean that if the load is beyond setting, the protection will clear that feeder without risk to the rest of the network. The remaining cables will not overload before the upgrades.

Transformer and switchgear upgrades in 2012 to both RGA[56] and PAR[57] substations have reduced the risks from high and medium to low. With the exception of the existing PAR switchboard, the risk has been lowered from high to medium due to both half busses sharing the same room and the absence of arc flash containment or ducting to the exterior of the building. The two new PAR 33 kV switchrooms, one for each half bus, do have flash containment and ducting to the exterior and so are rated as low risk.

The arc flash protection and containment at GRM and NST reduces the risk while housing 11 kV buses in the same room at each substation. Transpower's new TIM GXP 11 kV substation has separate rooms for each bus and also full arc flash containment, reflecting the relative importance of the substation.

The new RGA T2 11 kV switchboard arc flash protection and containment rating and is in a separate building from the older T1 11 kV switchboard without flash protection or containment.

7.4.3.3 Risk to incoming supply

The highest risk category of substations is the reliability of the incoming supply. Typically, the incoming supply is provided by Transpower. In cases where the substations are supplied via a single feeder, necessary repairs result in outages. To reduce the level of risk, detailed studies are undertaken to determine the costs and benefits of duplicate feeders or alternative generation options.

7.4.3.4 Risk to ripple injection plant

Our ripple injection plants are a critical element in the management of controllable load on our network. With constraints in the transmission network requiring load to be shifted, failure of a ripple injection plant creates the risk of load curtailment during a constraint period and a financial penalty in the form of excess transmission charges. All ripple injection plants require critical spares to be kept.

7.4.3.5 Environmental risks

Snow and wind typically create high risks in the Mackenzie area of our network. Our design standards ensure appropriate materials that meet the extreme weather conditions are used. For example, the 11 kV switchroom at the STU substation has been elevated to minimise flood risk. Transpower will elevate any new work at the substation.

[56] Addition of T2 transformer including 33 and 11 kV switchgear.
[57] Replacement of both banks with larger transformers and indoor 33 kV switchgear.

Earthquakes pose a significant risk of network interruption and difficulty in supply restoration. The likelihood of an earthquake on our network has been deemed 'possible'. The possibility of an Alpine Fault[58] event is 1 in 50 years. The impact of an earthquake event would be moderate, making this a high risk event for our network.

Following an earthquake, checks will be required to ensure substations close to the fault are seismically restrained. An earthquake on the Alpine Fault could cause some Twizel and Tekapo consumers to be without supply for several weeks. The high risk at CD1 and CD2 substations reflects the nature of supply security, while the Mackenzie substations are closest to the Alpine Fault and the area of the largest expected disruption.

The 2012 transformer upgrades at PAR and RGA substations have reduced the earthquake risk from moderate to low due to the addition of new seismically designed assets, foundations, and buildings.

An extreme tidal wave would be a risk to STU, PAR, and TIM substations. The likelihood of a tidal wave is high and, accordingly, the level of risk is unacceptable.

The NST substation has additional room and facilities to provide a second base for control room operations and back-up ICT servers in the event of a disaster damaging or destroying the Washdyke offices and depot.

7.4.4 Risk management strategies

We manage risk through:

- elimination
- isolation
- minimisation.

In section 7.4.4 we outline how we use our three strategies to manage risk to our network assets. How we review our process in relation to assigned risk levels, evaluate new risks, and apply treatments to lower risk for each asset category is discussed below.

Table 7.5 summarises the qualitative results for the level of risk for the remaining asset categories after applying the risk matrix for the likelihood and consequences of each listed event.

7.4.4.1 Sub-transmission

The 33 kV cables (sub-transmission) on our network are high risk as they have the potential to interrupt supply to a large number of consumers. Restoration takes from one to two days, and sub-transmission is expensive to repair. The main hazard is cable strikes (from digging by third parties). Fortunately, 33 kV cables are few in number, and the risk treatment is relatively inexpensive and is mitigated by contractors obtaining plans of cable locations prior to planned excavations and requiring supervised excavation near cables.

[58] The Alpine Fault is a geological, right-lateral strike-slip fault that runs almost the entire length of the South Island. It forms a transform boundary between the Pacific and Australian Plates. More information can be found at http://en.wikipedia.org/wiki/Alpine_Fault

We are now a member of 'beforeUdig'. Contractors can request plans of our assets through www.beforeudig.co.nz.

Cable strike risk also applies to the TIM 11 kV sub-transmission cables, but with two extra cables recently added the risk is reduced. The 11 kV cable feeders supplying the Washdyke industrial area are now the focus of our attention. The risk will be further reduced through load growth driven feeder upgrades.

The 11 kV network has a higher degree of redundancy in urban areas due to the cables being installed in a ring configuration. Rural 11 kV distribution cables are typically radial feeder to a dedicated transformer. Risk mitigation relies on maintaining a stock of critical spares and providing location plans to contractors who need to excavate adjacent to in-service cables.

Risk to sub-transmission and 11 kV lines is controlled by utilising asset management practices to inspect, maintain, and renew assets proactively by identifying deterioration before the situation becomes critical.

7.4.4.2 Underground cables

We mitigate the high risk[59] to our cables by holding stock in critical spares[60]. Further work to fully assess the vulnerabilities of our cable network is underway in conjunction with the Civil Defence Emergency Management Group's (CDEMG) studies on lifeline utility performance during natural disasters and the interdependencies of utility systems. For further details, please see Section 7.3—Emergency response and contingency planning.

7.4.4.3 Transformers

Overhead and ground mounted transformers are at a high risk from earthquakes (low probability/high impact). To mitigate the risk, we hold transformers in critical spares, and asset management practices are in place to meet the medium and lower risk exposures.

Voltage regulators, reclosers, and ring main units have moderate to low risk levels and are catered for through design standards and stock held in critical spares.

7.4.4.4 Low voltage (LV)

LV lines and cables are generally low risk. Risk is mitigated through stock in critical spares and our asset management practices that ensure quality standards are maintained.

LV distribution boxes are a collection of different box types and configurations. Different box materials carry different risk profiles. Ground mounted fibreglass boxes carry the highest risk as they can be damaged by vehicles. We keep the level of risk moderate to low through our programmed condition assessments, regular surveillance to ensure integrity is maintained, and work and design standards.

[59] The higher the cable voltage, the greater the impact on system reliability and supply restoration.
[60] Stock is generally held for normal repairs rather than natural disasters due to high stock holding costs and availability from suppliers.

7.4.4.5 Buildings

The risk of building failures has been addressed through seismic reinforcement projects completed shortly after the Canterbury earthquakes.

7.4.5 Network capacity

Our policy is to provide sufficient capacity to meet consumer demand. Accordingly, we design expansions on our network taking into consideration the projected load growth for the area.

7.4.6 Operational security

Operational security is the risk of disruption to electricity supply and inadequate network capacity. Capital investment for network security is evaluated based on:

- the estimated cost to consumers of energy not supplied (based on the Electricity Authority's Value if Lost Load)
- the probability of an outage and the expected duration.

7.4.6.1 Resource Management Act 1991

The Resource Management Act 1991 is one of our major drivers. Of particular relevance to us are the provisions relating to:

- the discharge of contaminants into the environment
- the duty to avoid unreasonable noise
- the duty to avoid, remedy, or mitigate any adverse effect on the environment.

Our assets can be located in environmentally sensitive areas, requiring us to act in a manner that respects the environment.

The Act requires appropriate consent for new work and management systems for environmental and public safety issues of existing works. Our practices have been developed on the basis of being a reasonable and prudent operator who ensures that environmental and public safety issues are addressed.

7.4.6.2 Management of pollutants

Oil is widely used as an insulating and cooling medium in distribution assets, and replacement of these assets with non-oil filled types is not anticipated in the short or medium term. Control of this hazard is through oil containment provisions at zone substations and the routine inspection of all oil filled distributed assets. We have oil spill response procedures in place, and oil spill kits are available at all zone substations and on most contracting line trucks.

Noise arises from large transformers invariably associated with zone substations. Maintenance programmes include the upkeep of sound enclosures. Although noise complaints are occasionally received and investigated by the local councils, no remedial action has been required to date.

7.4.6.3 Electromagnetic fields

Health effects of power frequency electromagnetic fields (EMF) have commanded international attention in the past. However, no conclusive evidence has emerged in regard to the negative health effects of such fields. Copies of the National Radiation Laboratory booklet on the effects of EMF are made available to concerned customers.

7.4.6.4 Risk management improvements

Plans to improve the management of risks on our network will require the qualitative study to be extended with the completion of a formal risk register. The register will strengthen our risk management process and drive regular reviews of risk performance and new risk development, thereby providing continuous process monitoring and risk review.

In accordance with the Health and Safety in Employment Act 1992 and the Electricity (Safety) Regulations 2010, we have a database that records and manages risks to our network.

8. ASSET MANAGEMENT MATURITY ASSESSMENT

8.1 Introduction

Chapter 8 discusses our asset management maturity and identifies improvements that we intend to make to asset management systems and processes.

8.2 Asset Management Maturity Assessment Tool

The Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT) forms part of the Information Disclosure Requirements[61], and consists of 31 questions, which are a subset of the 121 questions of the Institute of Asset Management's PAS55 Asset Methodology. The AMMAT is intended to assist interested persons to assess the way that we manage our processes and people through the following capability assessment areas:

- asset strategy and delivery—process
- documentation, controls, and review—process
- systems, integration and information management—process
- communication and participation—process
- structure, capability, and authority—people
- competency and training—people.

The AMMAT requires electricity distribution businesses to self-assess asset management maturity by applying a score of 0 to 4 to each question. We scored ourselves with a maturity level of 1 to 3.

- 1—we have a basic understanding of the standard and are in the process of deciding how the elements of the standard will be applied, and we have started applying the standard.
- 2—we have a good understanding of the standard and have decided how we will apply the elements of the standard, and work is progressing on implementation.
- 3—all the elements of the standard are in place, are being applied, and are integrated.

We use the latest EEA Guide to the AMMAT[62] (EEA AMMAT Guide) to help us identify our level of maturity for each AMMAT question. For each question the Guide lists a number of requirements that should be evidenced in order to score a particular maturity. When we fulfil the evidence requirements for a maturity level and only partially fulfil requirements for the next maturity level, we score ourselves at the level we partially fulfil (i.e. we round our scores up).

Table 8.2 provides an extract of the information that we provide in Schedule 13: Report on asset maturity. The table provides the question number, the question, the score that we gave ourselves, as well as a comment as to what the score means in regard to our asset maturity.

[61] Commerce Commission, Electricity Distribution Information Disclosure Determination 2012, No. NZCC 22, 1 October 2012, clause 2.6.1(5).
[62] Electricity Engineers' Association's Guide to Commerce Commission Asset Management Maturity Assessment Tool, March 2014.

8.2.1 Changes to our AMMAT scores from last year

Our AMMAT scores have stayed static from last year with the exception of questions number 37 and 105, where our scores have increased from 2 to 3 and 1 to 3 respectively. The main reason for improvements in the scores is our decision to invest in the OneEnergy asset management system. The process undertaken to utilise the OneEnergy system has satisfied a number of evidentiary requirements in the AMMAT review, namely through the scope of our asset management requirements and an audit of our current system.

Once the new system is implemented, we expect a steady improvement in our AMMAT scores. The restructure of our Network Department that is currently underway (please see Chapter 2 for more information) is a result of the review of our network and asset management requirements and will also contribute to higher AMMAT scores.

8.3 Continuous improvements to our asset management system

Our current Asset Management Policy was approved in July 2011 and has been communicated to all staff via InfoWorld, our new file storage and information sharing system. A new Policy is currently in draft. Currently, our Asset Management System is inherent in the AMP. As part of our AMMAT self-assessment we plan to make the EAM a separate document

The AMS will be created using the EEA AMMAT Guide, in conjunction with the AMMAT to assess our present level of maturity and to identify what action is needed to reach our target maturity level. Identified actions are grouped into asset management areas and prioritised within the Network Development Plan. The actions required for each asset group will form the group's asset strategy, while the collective group strategies will form the EAM and, ultimately, the AMP. Our asset management framework is described in Figure 8.1.

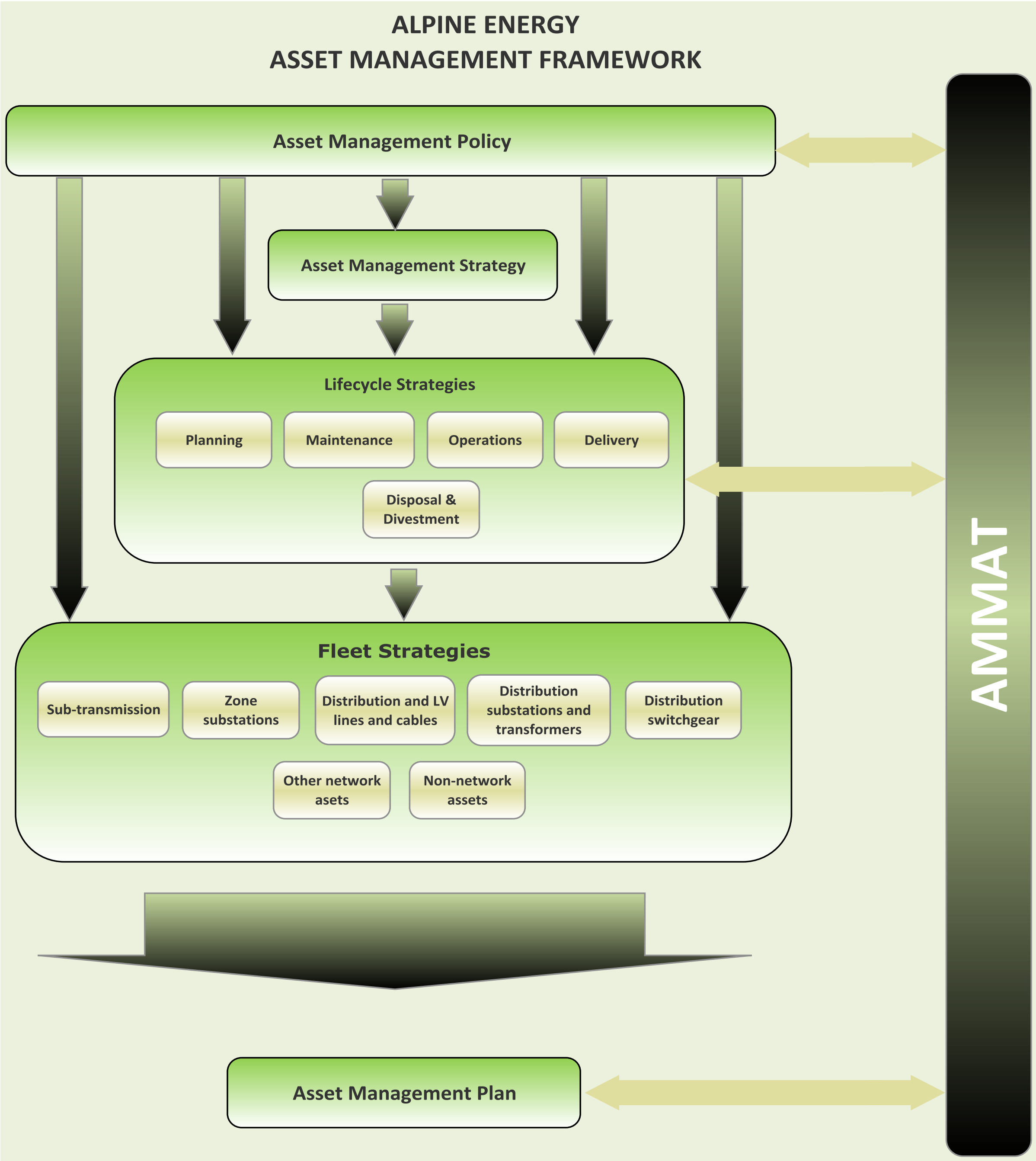

Figure 8.1 Planned document hierarchy and the AMS

In accordance with the framework we are updating our business process maps (BPMs) and developing our asset management related ICT systems.

8.3.1 Business process mapping

During 2014 we commence Stage 2 of our business process mapping. Through Stage 2 we are reviewing all of our existing business process maps to confirm that the process, as it is mapped, remains relevant, effective and efficient, and, where appropriate, change the existing process to take advantage of continuous improvements identified since Stage 1.

8.3.2 Asset Management System's information upgrade

We are in the process of upgrading, replacing, and securing a number of our information technology systems *ICT), which are integral to our EAM. In August 2011 we engaged Deloitte to carry out a complete review of our ICT needs. The report highlighted the fact that our systems were outdated, and we were inadequately prepared for disaster recovery. Based on Deloitte's findings, we decided that we needed a fresh approach to ICT for the company as a whole.

Over the next five years we plan to completely overhaul our ICT systems to give us the tools we need to provide better service to our customers.

With the exception of GIS and our operational asset register database, our systems are not fully integrated. Consequently, individual data is often entered separately into more than one package in order to satisfy the different database and software package requirements. All of our systems will be integrated with the implementation of the OneEnergy asset management system. Where appropriate, the new system will also replace paper and spreadsheet based processes.

8.3.2.1 Improving asset knowledge quality

Effective asset management, as well as any improvements to related ICT systems, can only happen with quality data (e.g. technical asset description, age, condition, and location of assets).

The field capture of our overhead distribution system has improved the accessibility and quality of our asset data, although gaps remain. Among the improvements is the unique pole identification system, which allows field staff to reference a number from the field back to the electronic record. However, information on underground cables will remain a paper based system until it is practical to place this information on GIS.

Asset condition information also remains a key area for enhancement. Significant progress has been made over the recent years with condition assessments conducted by NETcon on distribution boxes and distribution transformer installations.

GIS software and application development now allows accurate GPS information to be processed on the move.

8.3.2.2 GIS upgrade

Our GIS is an internally developed system that is an integral element of the EAM. We are in the process of completely replacing the current system with a new ESRI GIS system. The new system will provide:

- a fit-for-purpose facility for identifying assets to ensure compliance with the Electricity (Safety) Regulations 2010, clause 46 (1): '[t]he owner of works must keep such records and plans of those works as will enable the owner, if required, to readily locate any fittings or works'
- information for operational purpose (both normal day-to-day and emergency use), not including switch or isolation statuses
- easy reporting on asset types and asset information for maintenance purposes

- asset details to allow our New Connections Team to design and plan new extensions
- a single source of truth for all asset data for load flow modelling (using Powerstation ETAP)
- a compatible interface with other applications within the EAM, including the OneEnergy asset management system, SCADA, and the ICP Database.

8.3.3 SCADA upgrade

We have completed the upgrade from our existing iFix system to Survalent. The upgrade was triggered by our increasing demand for data acquisition from the field, the current version of iFix coming to the end of its life cycle, and the improvements in functionality and system stability that the Survalent system offers compared to the new version of iFix. We have also upgraded the hardware the systems run on and moved to a dedicated server environment.

8.3.4 Supporting documentation

The development of the AMP is closely tied to the overall development of our asset management systems and processes. As systems and processes mature, we will be better able to communicate our systems and procedures in our AMP. We plan to enhance the AMP in three stages, over a three year period. Stage one and two includes the restructure of the document through incremental changes, including the layout and overall structure. Stage three will commence once we finalise our EAM, as described earlier in Section 8.3—Continuous improvements to our asset management system.

Table 8.1 shows areas in our AMP identified as in need of enhancement.

Description of Compliance Requirements from Attachment A of the 2012 Information Disclosure	Intended measure to resolves
1.3 Close alignment with corporate vision and strategy	Stakeholder requirements for the efficient, safe and reliable delivery of energy are found throughout the AMP. However the introduction of the NDP (see Section 5.10) will make linkages more identifiable.
2.4 Specifically support the achievement of disclosed service level targets	We are enhancing our processes so that our service level targets better impact on our planning and lifecycle management. The AMMAT review (described in Section 8.3) will help to improve our Capex planning process in terms of resourcing, while the NDP will help align available resources with planning options.
2.8 Consider the organisational and contractor competencies and any training requirements	The AMMAT review (described in Section 8.3) will help to improve our Capex planning process, while the NDP will help align corporate goals with planning options.
2.9 Consider the systems, integration and information management necessary to deliver the plans; • how the asset management strategy is consistent with	See Section 8.3—Continuous improvements to our asset management system..

Description of Compliance Requirements from Attachment A of the 2012 Information Disclosure	Intended measure to resolves
the EDB's other strategy and policies	
3.14 An overview of asset management documentation, controls and review processes	We are enhancing our review processes, details can be found in Section 8.3—Continuous improvements to our asset management system
3.14 (ii) describe the processes developed around documentation, control and review of key components of the asset management system; (v) audit or review procedures undertaken in respect of the asset management system.	We are enhancing our review processes, details can be found in Section 8.3—Continuous improvements to our asset management system.
3.15 (i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants	We do not have a communications plan at present, which is consistent with other electricity distribution businesses (EDBs) of our size. However the AMMAT review, see Section 8.3 of the 2015 AMP may impress on us the need for a communication plan.
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation	We are enhancing how we measure asset performance. See Section 8.3 for more information.

Table 8.1 Areas in the 2016 AMP identified for further development

Assessment category	Question no.	Question	Current year	User guidance
Asset strategy and delivery	10	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?	1	An early draft of resource requirements is in place. We have yet to draft a resourcing strategy.
	11	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	1	An early draft of communication strategy is in place. We have yet to draft a communication plan.
	26	How does the organisation establish and document its AMP(s) across the life cycle activities of its assets and asset systems?	2	Our AMP is in place, but we are yet to fully develop our AMS. When the AMS is completed we can ensure that the AMP aligns with the AMS.
	33	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?	4	We have a comprehensive Emergency Preparedness Plan in place that supports us to manage the continuity of critical asset management activity in an emergency event. Our plan is part of our Public Safety Management System that ensures consistency between our policies and strategies around asset management objectives.

Assessment category	Question no.	Question	Current year	User guidance
Asset strategy and delivery	69	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	We have developed a Risk Management Policy and are in the process of identifying asset related risk across the asset lifecycle. We are in the process of implementing a risk management framework.
	91	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of AMP(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	1	We have an early draft for implementation and control of AM activities in place, the draft however does not contain detailed information on AM processes.
	109	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non–conformance?	3	We have comprehensive and proven processes for routine and preventive inspection, maintenance and performance programmes. Our investigation processes fully document incidents of asset failures taking note of nonconformities to establish root cause. Determining if there is appropriate preventative action to ensure similar incidents do not occur in the future is a key part of that process. Chapter 6, of our AMP provides detailed description of our inspection and maintenance programmes.

Assessment category	Question no.	Question	Current year	User guidance
Documentation, controls, and reviews	45	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	1	We have an Alliance Agreement with our preferred contractor, NETcon. We meet weekly with NETcon to discuss performance, operational progress and other relevant issues. The meetings are recorded in meeting minutes. We have early drafts for selection criteria, contract management processes and contracts in place. We have yet to implement a review process.
	59	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	We have completed the mapping or our processes under our BPM project. Copies of all BPMs are available to staff on our intranet. During 2014 we will undertake stage two in which we will review and revise our existing BPMs for continuous improvement. We are continuing to develop out ICT systems, where appropriate, to improve and record key processes.
	82	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	1	We have compiled a compliance register that lists all of our compliance obligations. We report by exception to our board every quarter. The register is used as part of the overarching risk management plan that is linked to our asset management practices. We have yet to fully document our risk and control measures.

Assessment category	Question no.	Question	Current year	User guidance
Documentation, controls, and reviews	88	How does the organisation establish implement and maintain process(es) for the implementation of its AMP(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	We have document control measures in place for all of our asset drawings. And we have established BPMs for the building of new assets. Currently we hold information in multiple systems, which make it difficult to demonstrate that lifecycle activities are carried out under specific conditions that are consistent with asset management policies and strategies. Installing a new asset management system will greatly assist us to demonstrate that we meet this requirement. We are now reviewing our initial BPMs
	95	How does the organisation measure the performance and condition of its assets?	1	Condition assessments are predominately paper based records. There are some gaps in the historical information held. Part of the installation of a new asset management system will be data cleansing and ratification. Once complete we would expect an increase in score. We are yet to formalise or determine measures to review our processes.
	105	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	We are now installing our new AMS. Our AMS has been designed around the review of our previous asset management systems and our present and future requirements.

Assessment category	Question no.	Question	Current year	User guidance
Documentation, controls, and reviews	113	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	1	An early draft of the continuous improvement processes are in place and there is evidence of plans to complete and authorise the resulting actions.
Systems, integration, and information management	31	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	Since 2005 we have recruited additional staff to ensure that our work plan can be completed. For example, in 2005 we had one network engineer and eight support staff. In 2012 we had grown to six network engineers and twelve support staff. The Board approves unplanned works and notes monthly variances between budgeted and actual expenditure. Our current weakness is that we tend to be more reactive than proactive. We are working to resolve our weaknesses.
	37	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	The roles and responsibilities, selection criteria and review processes for the appointment of members of the asset management team are documented, but have not reviewed against our strategies and objectives. We have developed and are currently recruiting more management to look after key network appointments. The appointments have been made in line with our AM strategy outlined in Chapter 8 of our AMP.

Assessment category	Question no.	Question	Current year	User guidance
Systems, integration, and information management	62	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	We are in the early stages of capturing AM information requirements.
	63	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	1	Data verification, ratification, and cleansing are done on an ad hoc case-by-case basis. Overall our asset management system is an informal system that includes GIS, a bespoke AMS, and paper records. We will look to improve our score during 2016 as we complete the data cleansing of our existing systems as a precursor to the installation of new systems.
	64	How has the organisation ensured its asset management information system is relevant to its needs?	1	A function of the newly created ICT Manager role will be to develop the ICT systems around our AMP requirements based on the process identified by the BPM project. We are establishing a review process.
Communication and participation	27	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?	1	We circulate a copy of our AMP to our principle contractor, shareholders, large consumers, and key staff. A copy of our AMP is available, at reception and on our website. We do not, however, meet with large consumers or other smaller contractors; nor do we present all staff with the key components of the AMP. We leave it to stakeholders to read and interpret the AMP themselves.

Assessment category	Question no.	Question	Current year	User guidance
Communication and participation	3	To what extent has an asset management policy been documented, authorised and communicated?	2	We have implemented an asset management policy and have plans to review what is required to improve our score.
	42	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	1	An early draft of the communication strategy is in place.
	53	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	Our AMP is made available to all staff on our website and hard copies are distributed to the asset management and engineering teams. We meet with our contractors each month to discuss the progression of the works programme. We hold regular shareholder meetings where our asset management programme can be discussed. Our stakeholder engagement for consumers tends to be ad hoc. We will need to improve our communications to better our score.
Structure, capacity, and authority	29	How are designated responsibilities for delivery of asset plan actions documented?	1	An early draft of the designated responsibilities is in place, but we are yet to make the draft final.

Assessment category	Question no.	Question	Current year	User guidance
Structure, capacity, and authority	99	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	Our Emergency Preparedness Plan supports us to respond to emergency situations in an appropriate and timely manner. However, the manual nature of recording events does not allow us to score ourselves higher than a 2 at this time. A new asset management system that supports the centralisation of documentation will greatly assist us in improving our score in the future.
	115	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	1	We recognise the need for knowledge acquisition, but have not drafted plans for any process.
Competency and training	40	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	1	An early draft of the resource requirements is in place, but we have not yet drafted a resourcing strategy..

Assessment category	Question no.	Question	Current year	User guidance
Competency and training	48	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	We do not currently break asset management activities down to a sufficiently disseminated level to be able to demonstrate that we align activities to the development and implementation of our asset management system.
	49	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	We hold a comprehensive database of our staff competencies and those of our preferred contactor, NETcon, and subcontractors. We identify the training requirements by considering the planned work programme and the competencies that the work to be carried out will require. Enduring competency requirements are linked to our AMPs will be a function of our Alliance Agreement with NETcon..
	50	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?	3	Our comprehensive database, discussed above, is maintained by the Compliance and Training Manager as a function of the position. Our contractors are able to access the database and view and update their competencies.

Assessment category	Question no.	Question	Current year	User guidance
Competency and training	79	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	1	We have early drafts for resourcing, competency and training requirements in place and have plans to progress the drafts.

Table 8.2 Extract of Schedule 13: Report on asset maturity

APPENDIX A SUMMARY OF 11 kV FEEDERS

Table A.1 provides a summary of the 11 kV feeders on our network.

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD (MW)
ABY0111	Albury	2732	Raincliff	92	2,347.5	114	87.33	1.86
ABY0111	Albury	2742	Cave	226	4,836.5	392	207.29	1.55
ABY0111	Fairlie	F374	Cricklewood	38	1,407.5	51	31.682	0.53
ABY0111	Fairlie	F380	Fairlie Rural	290	8,667.5	650	212.594	1.34
ABY0111	Fairlie	F383	Fairlie Township	7	1,500	273	2.718	0.54
BPD1101	Bells Pond	CB12	Ikawai	110	6,600	145	69.249	3.92
BPD1101	Bells Pond	CB13	Waikakahi	84	3,465	105	55.113	1.38
BPD1101	Bells Pond	CB14	Tawai	99	5,400	305	56.17	3.67
BPD1101	Cooneys Rd	8	Drier 2					0.25
BPD1101	Cooneys Rd	9	WetProcess					1.90
BPD1101	Cooneys Rd	11	Boiler/Chiller No. 1					0.84
BPD1101	Cooneys Rd	12	Office					0.54
STU0111	Studholme	01	Otaio	194	9,222.5	310	114.628	4.98
STU0111	Studholme	02	Glenavy	75	5,607.5	107	35.971	2.19
STU0111	Studholme	03	Waimate	89	12,555	1,878	33.379	4.31
STU0111	Studholme	07	Waihaorunga	155	5,270	225	130.382	1.30
STU0111	Studholme	08	Mount Studholme	180	14,472.5	293	89.41	3.82
STU0111	Studholme	09	Morven	181	8,102.5	282	99.448	3.06
TIM0111	Grasmere	02	White St	6	2,950	364	2.17	1.42
TIM0111	Grasmere	05	Nile Street	6	2,650	572	2.571	1.53
TIM0111	Grasmere	06	Parkview Terrace	4	1,200	9	3.375	1.80
TIM0111	Grasmere	07	Douglas St	3	1,400	241	1.513	0.55
TIM0111	Grasmere	10	Ashbury Park	4	1,950	186	2.847	1.04
TIM0111	Grasmere	12	Selwyn St	7	3,100	534	2.284	1.61
TIM0111	Grasmere	15	Park Lane	6	2,600	462	2,684	1.66
TIM0111	Grasmere	16	Evans St/ North Mole	5	2,650	9	3.691	0.88
TIM0111	Grasmere	17	June Street	4	2,300	272	1.531	1.14
TIM0111	Grasmere	20	Hobbs St	5	2,600	409	2.003	1.42
TIM0111	Hunt	01	Harper Street	2	1,000	233	1.217	0.60
TIM0111	Hunt	02	Wilson St	5	1,900	325	2.357	1.16
TIM0111	Hunt	04	Baker St	4	1,900	395	2.217	1.20
TIM0111	Hunt	05	Le Cren Street	8	4,550	580	2.327	2.10
TIM0111	Hunt	07	Church Street – South Side	3	1,800	230	1.109	1.24
TIM0111	Hunt	10	Gibson St	3	1,200	173	2.266	0.83
TIM0111	Hunt	11	Rhodes St	6	2,350	590	2.594	1.44
TIM0111	Hunt	13	Clifton Terrace	4	1,900	486	1.527	2.08
TIM0111	Hunt	14	Church St – North Side	3	2,150	62	1.933	2.54
TIM0111	Hunt	16	Arthur St	6	4,200	236	1.842	1.65
TIM0111	North	03	Redruth 1					0.17

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD (MW)
TIM0111	North	04	Rose St	4	2,050	348	1.875	0.87
TIM0111	North	05	Craigie Ave	8	3,500	696	3.551	1.94
TIM0111	North	08	Barnard St	5	2,500	157	1.077	1.11
TIM0111	North	09	Port 1	1	500	2	2.038	1.01
TIM0111	North	10	Fraser St	5	2,800	22	2.391	1.45
TIM0111	North	11	Hayes St	6	3,800	76	1.874	1.22
TIM0111	North	12	High St	10	3,325	242	5.266	1.05
TIM0111	North	13	Port 2	3	3,400	13	2.289	3.36
TIM0111	North	16	Victoria St	5	2,400	329	1.683	1.38
TIM0111	North	17	Stafford St	5	3,900	189	2.193	1.67
TIM0111	North	18	Redruth 2					1.05
TIM0111	Pareora	CB3	SFF No. 1	NULL	NULL	1	0.338	2.44
TIM0111	Pareora	CB4	St Andrews	218	8,935	377	129.43	2.44
TIM0111	Pareora	CB5	SFF No. 2					2.48
TIM0111	Pareora	CB6	Normanby	173	6,540	533	75.516	1.73
TIM0111	Pareora	CB7	Holmestation	169	4,182.5	280	118.442	1.88
TIM0111	Pleasant Point	01	Waitawa	119	10,102.5	241	41.31	1.65
TIM0111	Pleasant Point	02	Sutherlands	81	1,872.5	110	52.293	1.11
TIM0111	Pleasant Point	04	Totara Valley	137	7,265	506	69.151	2.12
TIM0111	Pleasant Pont	05	Pleasant Point Township	48	3,020	317	26.561	1.16
TIM0111	Timaru	2692	North Street 1					3.43
TIM0111	Timaru	2702	Morgans Rd	23	5,760	892	9.34	3.28
TIM0111	Timaru	2712	Mountain View Rd	31	5,940	886	12.042	3.69
TIM0111	Timaru	2742	Seadown	293	17,727.5	782	99.395	5.18
TIM0111	Timaru	2762	AEL Yard	17	4,980	134	7.268	4.23
TIM0111	Timaru	2832	Grants Rd	22	5,650	1,118	7,815	2.77
TIM0111	Timaru	2852	Levels	404	9,645	834	160.075	2.66
TIM0111	Timaru	2862	Meadows Rd	16	9,425	78	6.771	4.79
TIM0111	Timaru	2942	Old North Rd	18	8,300	37	4.829	3.62
TIM0111	Timaru	2952	Highfield	64	10,297.5	1,319	23.944	4.40
TIM0111	Timaru	2972	Smithfield	12	2,760	293	5.892	5.06
TIM0111	Timaru	2982	North Street 2					3.36
TKA0331	Glentanner	M210	Glentanner	6	410	12	9.091	0.12
TKA0331	Tekapo	M200	Haldon-Lilybank	48	2,950	118	121.634	1.92
TKA0331	Tekapo	M201	Simons	7	1,775	6	6.02	0.85
TKA0331	Tekapo	M205	Godley	11	525	66	20.762	0.09
TKA0331	Tekapo	M206	Tekapo Township	21	3,965	287	8.392	2.14
TKA0331	Unwin Hut	M158	Village	5	2,300	14	5.265	1.00
TKA0331	Unwin Hut	M159	Village	6	815	69	4.951	0.50
TMK0331	Clandeboye Sub 1	T600	Tie to Milk Powder 2					0.00
TMK0331	Clandeboye Sub 2	T601	Fire Services	10	8,300	NULL	0.439	4.29
TMK0331	Clandeboye	T602	Whey	6	6,500	NULL	0.149	3.71

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD (MW)
	Sub 1		Processing					
TMK0331	Clandeboye Sub 1	T603	Lactose Plant	5	7,000	NULL	1.116	2.37
TMK0331	Clandeboye Sub 1	T605	Tie to Milford Clandeboye Rd					0.29
TMK0331	Clandeboye Sub 1	T609	Milk Reception	3	2,500	NULL	0.469	0.78
TMK0331	Clandeboye Sub 1	T610	Chilled Water No. 1	4	6,000	NULL	0.55	2.64
TMK0331	Clandeboye Sub 1	T611	Effluent Plant	5	6,000	NULL	0.494	2.19
TMK0331	Clandeboye Sub 1	T612	Milk Treatment	2	4,000	NULL	0.554	1.13
TMK0331	Clandeboye Sub 1	T613	Rolleston Rd					3.03
TMK0331	Clandeboye Sub 1	T614	Tie to Powder Handling	1	1,500	NULL	0.532	1.26
TMK0331	Clandeboye Sub 2	T650	Tie to Milk Powder 1					0.00
TMK0331	Clandeboye Sub 2	T651	Milk Powder 3	7	19,000	NULL	0.246	6.31
TMK0331	Clandeboye Sub 2	T652	Tie to WPC	1	1,500	NULL	0.411	2.33
TMK0331	Clandeboye Sub 2	T653	Chilled Water 3	4	3,200	NULL	0.318	1.19
TMK0331	Clandeboye Sub 2	T654	Tie to Boiler House					0.00
TMK0331	Clandeboye Sub 2	T658	Milk Powder 2	6	16,000	NULL	0.172	3.51
TMK0331	Clandeboye Sub 2	T659	Tie to Energy Centre 1					0.00
TMK0331	Clandeboye Sub 2	T660	Refrigeration	4	5,000	NULL	0.528	1.68
TMK0331	Clandeboye Sub 2	T661	Laboratory	3	4,500	NULL	0.364	1.43
TMK0331	Geraldine	G194	Speechly	304	16,533	1,749	152.618	2.27
TMK0331	Geraldine	G191	Geraldine Township					3.88
TMK0331	Geraldine	G156	Woodbury	302	8,225	669	152.837	3.74
TMK0331	Rangitata	2	Arundel	46	3,405	56	22.476	1.62
TMK0331	Rangitata	03	Mahan Road	63	5,385	85	32.77	3.23
TMK0331	Rangitata	04	Main South Road	57	5,650	81	32.357	1.93
TMK0331	Rangitata	11	Belfield	82	5,840	110	45.703	2.22
TMK0331	Rangitata	12	Orton	14	1,170	15	11.869	1.84
TMK0331	Rangitata	13	Rangitata Island	41	3,005	58	22.537	1.63
TMK0331	Temuka	01	Temuka West	9	51,675	417	5,159	2.19
TMK0331	Temuka	02	Milford	193	13,880	466	95.53	2.77
TMK0331	Temuka	03	Winchester	211	9,937.5	571	76.665	2.97
TMK0331	Temuka	07	Rangitata	90	6,800	132	44.164	3.26

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD (MW)
TMK0331	Temuka	08	Temuka East	73	13,080	1,771	23.067	4.83
TMK0331	Temuka	09	Waitohi	170	5,435	274	101.103	1.88
TWZ0331	Twizel	Z1	Urban No. 1	22	4,230	625	6.986	1.47
TWZ0331	Twizel	Z2	Urban No. 2	29	5,370	644	11.855	1.51
TWZ0331	Twizel	Z3	Industrial	1	50	1	0.207	0.25
TWZ0331	Twizel	Z4	Twizel Rural	42	2,230	97	37.642	0.39

Table A.1 Summary of 11 kV feeders

APPENDIX B CAPEX 12 MONTH WORKS PLAN FOR 2016/17

Table B.1 below provides a list of non-material projects that we will either complete during 2016/17 or start and complete during 2016/17. For material projects, please see Section 5.7—Material capital expenditure projects.

Projects are listed in real (constant) dollars and in thousands ($000).

Alpine Energy Limited works programme projects	Budgeted cost ($000)
Various O/H refurbishment and renewals	29,664
Rolleston Rd upgrade	112
Wilkin St TMK upgrade	90
33 kV softwood pole replacements	2,000
Mt Nessing Rd upgrade	280
Lysaghts Rd refurbishments	294
Tasman River crossing	100
Chamberlain Rd	84
WDO–BPD 110 kV double circuit	4,600
ABS replacements	1,095
New ABS's	565
ABS relocations (T537, ABS 1556)	-
Transformers distribution for subdivisions, extensions and replacements	3,400
Voltage regulator and capacitor bank installations	1,320
Distribution sub refurbishment	2,020
Two pole distribution sub refurbishment	1,540
Replacement RMUs	2,550
New RMUs	1,600
Recolsers new	1,240
Recloser replacements	950
Earthing	1,100
Zone substation protection replacement	1,850
Mobile sub/gen site preparations	320
33/22 kV CB and recloser replacement	850
Ripple plant replacement and LS rework	500
Ripple plant enhancement to suit T1 addition	100
Ripple plant cell upgrade	150
New and refurbishment of equipment	1,500
Zone substation upgrade	1,900
Zone substation upgrade	420
33 kV upgrade	450
Comms and RTU	2,700
SCADA Master Station modules	1,465
SCADA and pole top equipment automation (e.g. reclosers)	1,200

Table B.1 12 month works plan projects

APPENDIX C CAPEX 10 YEAR WORKS PLAN FROM 2016/17

Table C.1 below lists the works projects for the next 10 years.

Projects are listed in real (constant) dollars and thousands ($000).

Alpine Energy Limited works programme projects	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Various O/H refurbishments and renewal	3,423	2,350	2,891	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Rolleston Rd upgrade	112	-	-	-	-	-	-	-	-	-
Wilkin St TMK upgrade	90	-	-	-	-	-	-	-	-	-
33 kV softwood pole replacements	200	200	200	200	200	200	200	200	200	200
Mt Nessing Rd upgrade	280	-	-	-	-	-	-	-	-	-
Lysaghts Rd refurbishment	294	-	-	-	-	-	-	-	-	-
Tasman River crossing	100	-	-	-	-	-	-	-	-	-
Chamberlain Rd	84	-	-	-	-	-	-	-	-	-
WDO–BPD 110 kV double circuit	50	150	2,300	2,100	-	-	-	-	-	-
ABS replacement	140	135	120	100	100	100	100	100	100	100
New ABS's	60	60	60	60	60	60	25	60	60	60
ABS relocations (T1537, ABS 1556)	-	-	-	-	-	-	-	-	-	-
New connections and subdivisions	2,400	2,400	2,400	2,400	2,000	2,000	2,000	2,000	2,000	2,000
Transformers distribution for subdivisions, replacements and extensions	450	400	400	350	350	300	300	300	250	300
Voltage regulators and capacitor bank installations	180	180	180	120	180	120	120	80	80	80
Distribution sub refurbishment	220	250	250	250	250	160	160	160	160	160
Two pole distribution sub refurbishment	200	200	200	160	160	160	160	100	100	100
Replacement RMUs	300	250	250	250	250	250	250	250	250	250
New RMUs	250	150	150	150	150	150	150	150	150	150
Reclosers new	180	180	180	100	100	100	100	100	100	100
Reclosers replacements	100	122	122	122	122	122	60	60	60	60
Earthing	200	100	100	100	100	100	100	100	100	100

Alpine Energy Limited works programme projects	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Underground cable upgrades (G)	300	300	300	350	300	300	300	300	300	300
Underground cable upgrades (R)	300	220	220	300	300	300	300	300	300	300
O/H to U/G conversions	430	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Zone substation protection replacement	200	200	150	150	150	200	200	200	200	200
Mobile sub/gen site preparations	200	120	-	-	-	-	-	-	-	-
33/22 kV CB recloser replacement	200	200	150	150	-	150	-	-	-	-
Ripple plant replacement and LS rework	100	-	400	-	-	-	-	-	-	-
Ripple plant replacement to suit T1 addition	-	100	-	-	-	-	-	-	-	-
Ripple plant cell upgrade	-	50	100	-	-	-	-	-	-	-
New and refurbishment of equipment	150	150	150	150	150	150	150	150	150	150
Zone substation upgrade	100	1,800	-	-	-	-	-	-	-	-
Zone substation upgrade	420	-	-	-	-	-	-	-	-	-
33 kV upgrade	200	250	-	-	-	-	-	-	-	-
Comms and RTU	400	300	250	250	250	250	250	250	250	250
SCADA Master Station modules	210	50	200	105	150	150	150	150	150	150
SCADA and pole top equipment automation (e.g. reclosers)	200	200	100	100	100	100	100	100	100	100
Consultants' investigations and reports	150	150	150	150	150	200	100	100	150	150
WDO GXP	-	-	2,700	3,100	-	-	-	-	-	-
33 kV cable from TIM to SDW	4,200	-	-	-	-	-	-	-	-	-
Second 11 kV switchboard and T1	1,500	3,000	-	-	-	-	-	-	-	-

Table C.1 10 year works plan projects

APPENDIX D APPENDIX D SCHEDULE 14a

Company name Alpine Energy Limited

For Year Ended 31 March 2016

Schedule 14a Mandatory Explanatory Notes of Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015))

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is part of the audited disclosure information, and so is not subject to the assurance requirements specified in Section 2.8—Accountabilities for asset management.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a).

In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

To derive the capital expenditure in nominal dollar terms, the constant price forecasts were inflated by approximately 1.5% per annum, on a straight line basis, based on New Zealand Treasury forecasts. To derive the 10 year forecast, 1.5% was selected as a conservative inflationary rate. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 1.5% per year.

Commentary on difference between nominal and constant prise operational expenditure forecasts (Schedule 11b).

In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year, as disclosed in Schedule 11b.

To derive the operational expenditure in nominal terms, the constant price forecasts were inflated by approximately 1.5% per annum, on a straight line basis, based on New Zealand Treasury forecasts. To derive the 10 year forecast, 1.5% was selected as a conservative inflationary rate. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 1.5% per year. The real expenditure is reducing to reflect the expected efficiency gains per annum that will be found by improvements to our processes and practices. We expect to share realised benefits with consumers by reducing our operating expenditure, in real terms, over the next 10 years. Therefore the difference between nominal and constant operational expenditure forecasts is a reduction of 1.5% per year.

APPENDIX E SELECTION OF EQUIPMENT

Equipment selected is based on the theoretical and electrical characteristic as outlined in the previous sections that includes selecting equipment that helps to meet our objectives of safe, efficient, reliable, and cost effective energy delivery.

We also attempt to standardise as much as possible, which in practical terms translates to the following materials and equipment being specified and used.

E.1 Sub-transmission lines

For more information on our sub-transmission lines, please refer to the AMP—Major Assets. Table E.1.1 describes key characteristics of equipment chosen for our sub-transmission lines.

Equipment type	Description
Conductor	Jaguar ACSR, 210.6 mm^2 Al equiv, 19.3 mm dia, 47 kN, 420/640 A at 50/75 °C Iodine AAAC, 118 mm^2 Al equiv, 14.3 mm dia, 27.1 kN, 290/450 A at 50/75 °C Mink ACSR, 63.1 mm^2 Al equiv, 11 mm dia, 21.8 kN, 185/285 A at 50/75 °C The above ratings were largely taken from the General Cables web page on 8/2/2010.
Poles	18.5 m, Hardwood, 12 kN (BPD-CNR 110 kV) 17 m 12 kN prestressed concrete, Humes ex Gladstone, (RGA Cct 2) 11 to 17 m, 8 kN and 12 kN Hardwood, 12.2 m 7.35 kN and 12.5 m 8 kN prestressed concrete, ex Firth 10.7 m mass reinforced concrete, ex NETcon.
Insulators	We have where possible kept with traditional glass and porcelain insulation. Surge arresters are the main exception. For the sake of public safety polymers other than EDPM are installed. Most polymer surge arrester housings are aging prematurely. Porcelain insulators – general range of product from NZI catalogue. All new 33 kV lines will be insulated with a superior NZI post type insulator instead of the pin type previously used. Strain insulators – generally glass disc ex Chinese manufacture for 11 and 33 kV work. Ball and socket ex Sediver have been adopted for 110 kV work. Post insulators – 110 kV NZI catalogue insulators have been adopted for 110 kV work. Due to supply and demand issues Sediver and McLeans composite insulators have also been used for 110 kV work to cover the porcelain short fall.
Zone protection	We have no Zone protection on 33 kV overhead lines. New sub-transmission will have a form of unit protection if it forms a mesh. Our standard substation protection comes from the SEL catalogue, a device like the 311C may be adopted. If the sub-transmission is a spur forming a transformer feeder, instantaneous over-current elements will be set as long as the element does not reach into the LV bus bar at the far end zone substation. Devices like the 311C or 351S or 351R will be applied.

Table E.1.1 Characteristics of equipment used for sub-transmission lines

E.2 Sub-transmission cables

For more information on our sub-transmission cables, please refer to the AMP—Major Assets. Table E.2.1 describes key characteristics of equipment chosen for our sub-transmission cables.

Equipment Type	Description
Cables	400 mm^2 Al 1C and 3C, Al XLPE/HD CWS/MDPE, 11 and 33 kV, 530 A direct buried vis 424 A at 20% derating or 24.2 MVA at 33 kV or 8 MVA at 11 kV 300 mm^2 Al 1C and 3C, Al XLPE/HD CWS/MDPE, 11 and 33 kV, 467 A direct buried vis 373 A at 20% derating or 21.3 MVA at 33 kV or 7 MVA at 11 kV 1200 mm^2 Al 1C Al XLPE/HD CWS/MDPE installed for new sub-transmission 33 kV assets. Sub-transmission to NST is presently run at 11 kV. 945 A direct buried vis 756 A at 20% derating or 43.2 MVA at 33 kV or 14.4 MVA at 11 kV
Terminations	Generally heat shrink termination technologies are used. Very little use of cold shrink or elbow type technologies have been adopted to date. EN50181, Type C, outer cone cable couplers are used with the GHA 33 kV CB panels as standard for this class and type of switchgear.
Surge arresters	110 kV, ABB Exlim Station class porcelain 33 kV, ABB Exlim Station class porcelain, Ohio Brass Station and Riser Class ESP. 11 kV, Ohio Brass Station Class ESP, Cooper Evolution 10 kV Silicon.
Zone protection	New sub-transmission will have a form of unit protection if it forms a mesh. Our standard substation protection comes from the SEL catalogue, a device like the 311L may be adopted. If back up protection is required a device from Siemens/Reyrolle may be adopted. If the sub-transmission is a spur forming a transformer feeder, instantaneous overcurrent elements will be set as long as the element does not reach into the LV bus bar at the far end zone substation. Devices like the 351S or 351R or 751A will be applied.

Table E.2.1 Characteristics of equipment used for sub-transmission cables

E.3 Zone substations

For more information on zone substations, please refer to the AMP—Major Assets. Table E.3.1 describes key characteristics of equipment chosen for our zone substations.

Equipment type	Description
Sites	Sites are selected so that they are either central to the load of the day if expansion is going to be uniform throughout the existing area or toward the edge of an industrial area should expansion plans be identified for that area. Land purchase negotiations may alter the best site selection; options are required.
Buildings, yards, and structures	Modern design is undertaken so that: • buildings fit the local architecture • yards have equipment fitted on a low profile basis where possible Suitable landscaping is established to fit the local community.
Transformers	Zone substation transformers are either purchased new or transferred from another site/stock. New transformers are generally tendered, with offers called from three or four different manufacturers with local NZ representation and after sale service. To maintain commonality of design, a previously successful tenderer may be contacted for further supply, if the tenderer can successfully justify any changes to terms and conditions.

Equipment type	Description
	Stock transformers are installed in either a refurbished condition or as is. The decision to refurbish is based on many criteria including size, age, perceived loss of life diagnosed by insulation aging testing and insulation testing. Smaller aged units may just be painted and not fully refurbished as the costs incurred are not justified.
Switchgear	We prefer to avoid SF_6 switchgear, but often SF_6 switchgear is unavoidable. Standard procurement is presently: • 110 kV, Areva GL312 • 33 kV, Areva GL107X adopted for sites at and above 4 kA fault level • 110 and 33 kV instrument transformers generally from Arteche's catalogue • 33 kV, Cooper NOVA (now VWVE38 obsolete) for sites below 4 kA fault level • 11 kV, RPS LMVP range of product for zone substations • 11 kV, Cooper NOVA for sites below 6 kA fault level • 33 and 11 kV NCT from TWS's catalogue. Some instrument transformers are also purchased from TWS. The first of procurement for evaluation of the following switchgear, 33 kV, Schneider Electric GHA
Protection	New zone substation transformers will have a form of unit protection, Our standard substation protection comes from the SEL catalogue, a device like the 387 may be adopted. Bus bars will either have an under impedance relay zone with a small time delay to grade with close in feeder protection or operation or high impedance bus bar protection fitted. Devices like the 311C may be adopted for under impedance relays and 587Z for bus bar protection from the SEL catalogue. Indoor switch gear may have arc flash detection protection fitted via inputs to the 751A relay from the SEL catalogue.
Auxiliary systems	Each station has a d.c. system of either 24 V or 110 V to supply essential equipment in the case of an a.c. power system failure. We prefer rectifiers and converters of d.c. to be convection cooled or have filters to avoid the ingress of foreign matter into the equipment. If a dual a.c. local service supply is not available a generator plug is installed on the wall of the station so essential services can be supplied after a portable generator is connected. If a new dual a.c. local service is installed, a manual/automatic change-over system is used, with manual/auto selection to a portable generator input should both local services be out of service.

Table E.3.1 Characteristics of equipment used for distribution lines

E.4 Distribution cables

Table E.4.1 describes key characteristics of equipment chosen for distribution cables.

Equipment type	Description
Cable	Selection of cable is based on two criteria: • required power flow • fault level presented with applied protection considered Cable types include: • 400 mm^2 Al 1C and 3C, XLPE/HD CWS/MDPE, 11 kV, 530 A direct buried vis 424 A at 20% derating or 8 MVA at 11 kV. 37.8 kA 1 sec or 21.8 kA 3 sec phase fault and 13.1 kA 1 sec earth fault. • 300 mm^2 Al 1C and 3C, XLPE/HD CWS/MDPE, 11 kV, 467 A direct buried vis 373 A at 20% derating or 7 MVA at 11 kV. 28.4 kA 1 sec or 16.4 kA 3 sec phase fault and 13.1 kA 1 sec earth fault. • 185 mm^2 Al 1C and 3C, XLPE/HD CWS/MDPE, 11 kV, 362 A direct buried vis 290 A at 20% derating or 5.5 MVA at 11 kV. 17.5 kA 1 sec or 10 kA 3 sec phase fault and 13.1 kA 1 sec earth fault. • 95 mm^2 Al 1C and 3C, XLPE/HD CWS/MDPE, 11 kV, 255 A direct buried vis 204 A at 20% derating or 3.8 MVA at 11 kV. 9 kA 1 sec earth fault. • 35 mm^2 Cu 1C, XLPE/HD CWS/MDPE, 11 kV, 191 A direct buried vis 152 A at 20% derating or 2.9 MVA at 11 kV. 5.1 kA 1 sec earth fault. • 35 mm^2 Al 3C, XLPE/HD CWS/MDPE, 11 kV, 149 A direct buried vis 120 A at 20% derating or 2.2 MVA at 11 kV. 3.4 kA 1 sec earth fault.
Terminations	Generally heat shrink termination technologies are used. Very little use of cold shrink or elbow type technologies have been adopted to date.
Surge arresters	11 kV, Ohio Brass Station Class ESP, Cooper Evolution 10 kV Silicon.

Table E.4.1 Characteristics of equipment used for distribution cables

E.5 Distribution substations—pole mounted

For more information on our pole mounted distribution substations, please refer to the AMP—Major Assets. Table describes key characteristics of equipment chosen for our pole mounted distribution substations.

Equipment type	Description
Poles	10 to 15 m, Hardwood 8 and 12 kN. 10 to 15 m, Softwood 8 and 12 kN. 9.5 and 11 m, prestressed concrete, ex Busck. 9.7 and 10.7 m, mass reinforced concrete, ex NETcon (soon to be out of manufacture).
Transformer	We seek supply of transformers, up to 2 MVA from NZ manufacturers. We find that industrial type transformers above 2 MVA can be economically procured from Australia so on the occasion we require alternative prices from New Zealand manufacturers.
HV switchgear	We predominately use 'drop out' or 'cut out' style fuses on a single phase basis for pole mounted transformers. Both fuses are suitable up to 12.5 kA fault levels. The occasional use is made of ganged drop outs for installations that may be subject to ferro resonance or a three phase spur fuse to three phase loads. If the fault level is above 12.5 kA ring main units are used. Ring main units have ratings up to approximately 20 kA.
LV fusegear	We predominately use HRC fuses in a range of holders. If a three phase service is taken then a ganged holder is preferred so that a clean three phase break is made.

Table E.5.1 Characteristics of equipment used for pole mounted distribution substations

E.6 Distribution substations—ground and underground mounted

We avoid the use of integrated substations, i.e. substations with HV switchgear included in the end box. If one component fails, we consider it easier to replace on component than replace a complex site.

We are sourcing 'T-Blade' type transformers to eliminate legacy transformer end box located 11 kV HRC fused cable 'T' connections. The philosophy is to have RMU, then 'T-Blade', then RMU, then 'T-Blade', and so on. The arrangement aids sites that do not have sufficient space to install an RMU for the transformer tee-off and reduces costs. Our preference is for the 'T-Blade' transformer connection to have diversity in that it has its LV interconnected to other transformers' LV windings.

Table E.6.1 describes key characteristics of equipment chosen for the selection of sites.

Equipment type	Description
LV fusegear	Sites are selected so that they are: • as safe as possible from public and traffic thoroughfare • removed from walls and outside of buildings to reduce fire hazards where possible • central to the load of the day if expansion is going to be uniform throughout the existing area • toward the edge of an industrial area should expansion plans be identified for that area • ideally within 200 m of significant loads • preferred to be on council road reserve rather than private residential land with easement For industrial sites the preference is to have the transformer as close as possible to the sites 415 V MCC, 11 kV switchgear may be remote. It is essential that the 11 kV switchgear is accessible, so there is a preference for berm mounting.
Enclosure	We prefer the use of Citypad then minipad and micro pad style transformers. We have not installed covered sites for a number of years.
Transformer	We seek supply of transformers from NZ manufacturers.
RMU switchgear	We have accepted the use of SF_6 filled ring main units (RMU). The supply of traditional oil filled equipment has either ceased or we have been advised that production has stopped. The general rule for new RMU purchase is: • for transformers requiring an HRC fuse of 40 A or less an ABB Safelink, so as to grade with the tight protection in the Timaru City, or • for transformers 500 kVA and above Schneider RN2c Ringmaster if the HV fuse in an ABB unit cannot be graded with upstream OC protection. Where a site is complex, that is, more than a cable in and out and a transformer tee, a four booth Safelink may be adopted (pending fuse size); otherwise a nest of RMUs is preferred over establishing a bus. The bus system reduces flexibility during releases and makes fault repair complex.
LV switchgear	At industrial sites the LV switchgear is generally the responsibility of the developer. Where there are multiple transformers we require all transformer secondary's to be run isolated from each other, which leads to interlocking systems being required on bus couplers. Our distribution substations generally have 400 V fuse-link board made up of: • DIN 1 vertical disconnect with solid links, 800 A rated up to 500 kVA, 1600 A for 750 and 1000 kVA. • DIN 3 vertical disconnect units, normally 630 A rated with fuse elements to suit. • Smaller DIN00 vertical disconnect unit to allow light wire connections for street light controls and maximum demand recording via electronic instrument. Transformers for a sole supply to a load may have a simple panel with one or two horizontal fuse disconnects.
Auxiliary equipment	Padmount transformers are generally fitted with a maximum demand instrument and street light controls from the ripple relay system.

Table E.6.1 Characteristics of site selection

E.7 Low voltage reticulation

For more information on LV reticulation, please refer to Section 3.3.9—LV reticulation lines and cables (including link and distribution boxes).

Table E.7.1 describes key characteristics of equipment chosen for LV reticulation.

Equipment type	Description
Cables	Selection of cable is based mainly on required power flow and length of run to avoid volt drop. The LV side of transformers can deliver very high fault currents, but circuits are generally protected with fuses that have very fast clearance times so fault current withstand is not normally taken into account. Neutral screen cables are used. General sizes are: • 300 mm^2 Al, 476 A direct buried vis 380 A at 20% derating or 264 kVA 400 V. At 200 m run this cable will supply 247 A or 162 kVA with 5% volt drop. • 185 mm^2 Al, 364 A direct buried vis 291 A at 20% derating or 200 kVA 400 V. At 200 m run this cable will supply 165 A or 109 kVA with 5% volt drop. • 95 mm^2 Al, 251 A direct buried vis 200 A at 20% derating or 138 kVA 400 V. At 200 m run this cable will supply 94 A or 62 kVA with 5% volt drop. We avoid the use of four core cables in public areas. It is preferred that a neutral screen is present as it is safer in case there is a piercing of the cable.
Link boxes	Link boxes are commonly installed in meshed reticulation so that two substations can be easily connected when the release of one substation is required. Non–metallic boxes are preferred with a common bus and a series of DIN3 vertical disconnect units. The actual make up varies as per the installation.
Distribution boxes	A range of locally procured distribution boxes are installed. Non-metallic boxes are preferred with reticulation cables rising for jointing via lugs and nut and bolt, then services taken to Red Dot or similar HRC fuse holders. Larger consumers may have smaller horizontal fuse disconnects installed.

Table E.7.1 Characteristic of equipment used for LV reticulation

APPENDIX F SCHEDULE 12c(ii) SYSTEM DEMAND

Maximum coincident system demand (MW)	Current year 31 Mar 16	CY + 1 31 Mar 17	CY + 2 31 Mar 18	CY + 3 31 Mar 19	CY + 4 31 Mar 20	CY + 5 31 Mar 21
GXP demand	134	137	140	143	146	149
Distributed generation output at HV and above	7	7	7	7	7	7
Maximum coincident system demand	141	144	147	150	153	156
Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
Demand on system for supply to consumers' connection points	141	144	147	150	153	156
Electricity volumes carried (GWh)						
Electricity supplied from GXPs	812	830	848	865	883	90114
Electricity exports to GXPs	14	14	14	15	15	15
Electricity supplied from distributed generation	26	27	27	28	28	29
Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
Electricity entering system for supply to ICPs	824	842	860	879	897	915
Total energy delivered to ICPs	794	812	830	547	865	882
Losses	29	30	31	31	32	33
Load factor	67%	67%	67%	67%	67%	67%
Loss ratio	3.6%	3.6%	3.6%	3.6%	3.6%	3.6%

Table F.1 Demand forecast

Table F.2 Schedule 12c(ii): System demand

GLOSSARY

The following acronyms and abbreviations are used throughout the AMP.

A	—	Ampere
AAC	—	All Aluminium Conductor
AAAC	—	All Aluminium Alloy Conductor
ABS	—	Air Break Switch
ACSR	—	Aluminium Conductor Steel Reinforced
ABY	—	Albury Transformer Substation
ADMD	—	After Diversity Maximum Demand
AMMAT	—	Asset Management Maturity Assessment Tool
AMP	—	Asset Management Plan
Al	—	Aluminium
BCL	—	Broadcasting Communications Ltd
BML	—	Balmoral Zone Substation
BPD	—	Bell's Pond Substation
Bus	—	Bus Bars
Capex	—	Capital Expenditure
CB	—	Circuit Breaker
CBD	—	Central Business District
CDEM Act	—	Civil Defence Emergency Management Act
CD1	—	Clandeboye No.1 Substation
CD2	—	Clandeboye No.2 Substation
CFC	—	Greenhouse Gas
CFL	—	Compact Fluorescent Lamp
CNL	—	Canal Road Substation
CNR	—	Cooney's Road Substation
Consumer	—	A person that consumes or acquires electricity lines services
Cu	—	Copper
Customer	—	A body which AEL has a direct contractual relationship with, normally in the form of a user of supply agreement, for example retailers and larger businesses
DCIU	—	Data Control and Interface Unit
DGA	—	Dissolved Gas Analysis
DNP	—	Direct Numeric Protocol

DO	—	Drop Out fuse
Dyn11	—	Transformer vector group
EC	—	Electricity Commission
EDB	—	NZ Electricity Distribution Businesses
EEA	—	Electricity Engineers’ Association
EF	—	Earth Fault
EMF	—	Electro Magnetic Field
FM	—	Frequency Modulation
FLE	—	Fairlie Substation
GEC	—	General Electric Company
GIS	—	Geographic Information System
GLD	—	Geraldine Zone Substation
GRM	—	Grasmere Zone Substation
GST	—	Goods and Services Tax
GTN	—	Glentanner Zone Substation
GWh	—	Giga Watt Hours
GXP	—	Grid Exit Point
HDI	—	Hunter Downs Irrigation
HLB	—	Haldon/Lilybank Zone Substation
HNT	—	Hunt Street Zone Substation
HV	—	High Voltage
Hz	—	Hertz
ICP	—	Installation Control Point
ICT	—	Information and Communications Technology
ID	—	Information Disclosure
IED	—	Intelligent Electronic Device
IPCC	—	Intergovernmental Panel on Climate Change
ISL-LIV	—	Islington Livingston
kN	—	kilo Newton
kV	—	kilo Volt
kVA	—	kilo Volt Ampere
kvar	—	kilo Volt Ampere reactive
LOS	—	Loss of supply

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At Alpine Energy we recognise that your complaint is important to you, and to us. We will endeavour to contact you within two working days of receiving your complaint to discuss the concerns you have and how we can find a resolution.This is a free service. In the first instance, any complaints should be sent to:

ALPINE ENERGY LIMITED

Chief Executive Officer
PO Box 530 Timaru 7940

Ph: 03 687-4300
Fax: 03 684-8261

mailbox@alpineenergy.co.nz
www.alpineenergy.co.nz

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ELECTRICITY AND GAS COMPLAINTS COMMISSIONER

PO Box 5875, Lambton Quay, Wellington 6145

04 914 4630
04 472 5854

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