ALPINE ENERGY LIMITED

Asset Management Plan 2015 - 2025

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Asset Management Plan 2015–2025

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Alpine Energy Limited
Meadows Road
PO Box 530
Timaru
7940
New Zealand
Tel: +64 3 687 4300
Fax: +64 3 684 8261
Web: www.alpineenergy.co.nz

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Foreword

The purpose of our 2015 Asset Management Plan (AMP) is to provide insight and explanation on how we intend to provide electricity distribution services. We will achieve this 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 for our stakeholders.

Our distribution network is in a fair to good condition. Assets built in the 1950s and 1960s are near the end of their 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 their useful life or have become uneconomic will be retired and replaced with alternative products.

We continue our reinvestment phase by identifying and committing funds for network developments. These developments are identified to best serve our consumers for the next 50 years (the average life of an electricity distribution asset).

Our tariffs and pricing methodology continue to support us to stay within the default price path set by the Commerce Commission.

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.

Please note that for 2015 our AMP consists of two documents. The first document, the 2015 Asset Management Plan (AMP), is similar in layout and content to the 2014 AMP. However, information on major network assets and Transpower GXPs has been placed into a second document called the Major Network Asset Management Plan. This has been done to provide our staff and contractors with key information on major assets and development in the most accessible form.

Together, the AMP and MNAMP have been published to meet our regulatory requirements for asset management under the Electricity Distribution Information Disclosure 2012.

We encourage consumers to comment on both our MNAMP and AMP, as well comment on the approach taken to maintain a cost effective, safe, and reliable supply to South Canterbury.

The Directors

Alpine Energy Limited

Liability disclaimer

The information and statements made in this AMP are prepared on the assumptions, projections, and forecasts made by us, and represent our intentions and opinions at the date of approval—25 March 2015.

Circumstances will change, assumptions and forecasts may be proved to be wrong, events may occur that were not predicted, and we may, at a later date, decide to take different actions from those we currently intend to take as expressed in this AMP.

We cannot be held liable for any loss, injury, or damage arising directly or indirectly as a result of use or reliance on any information contained within this AMP.

Director certification

Certification for Asset Management Plan 2015 to 2025

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 2015 to 2025 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
25 March 2015

Alister John France
25 March 2015

1. Executive summary

1.1 The purpose of the plan

The AMP provides insight and explanation on how we intend to provide electricity distribution services. We will achieve this 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 for our stakeholders.

The AMP identifies the major initiatives and projects that will meet stakeholder and consumer requirements for the planning period. Preparation of the AMP in this format enables us to comply with the mandatory disclosure requirements set out at *Attachment A—Assets Management Plans* of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015).

1.2 Key assumptions

Our asset management decision making processes are based on key assumptions. These assumptions are described further below and throughout the document, where highlighted.

1.2.1 General economic assumptions

NZ 90 Day Bank Bill interest rates were at a high of 3.67%[1], up from 2.79% in December 2013, a year previously.[2]

ANZ's NZ Economic Outlook of December 2014 reported that New Zealand's inflation rates are expected to fall below 1% by the end of 2014 and are expected to remain well below the midpoint of the inflation target until well into 2016. These low interest rate conditions support the investment rates as proposed in our AMP.

The signals reported in ANZ's report of last year that interest rates might begin to rise during 2014, as inflationary pressures from outside increase their effect on the New Zealand economy, did not occur. The RBNZ's four OCR increases appear to have had the desired effect.

The "ANZ Regional Trends" of November 2014 reported national year-on-year economic growth peaking at 4.0% in June 2014. Growth in the South Island reached +4.3% y/y compared with +3.5% y/y in the North Island.

Canterbury Region's year-on-year growth of 4.7% was second only to Northland's of 6.3% [3]. The report noted that business sentiment in Canterbury was down but higher than the other regions. The sliding dairy prices in 2014 had affected sentiment but the majority of respondents were positive with focus on the medium-term outlook.

[1] As at 31 December 2014.
[2] Refer to the Reserve Bank of New Zealand's (RBNZ) latest Financial Stability Report of November 2014 for details of the RBNZ's current view of the New Zealand economy.
[3] Compared to 6.2% for the year to June 2014.

ANZ's "NZ Economic Outlook" of December 2014 has estimated the GDP growth in 2014 at 3.2% (compared with 2.6% in 2013). They estimate the GDP annual average growth in 2015 will be 3.0%.

1.2.1.1 Meeting increasing demand

The demand for new connections to meet additional load for irrigation and dairy conversions was steady in 2014. There has been an increase in upgrades and rationalisations to existing connections.

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

Locally, network growth is driven by irrigation development and is close to historical long-run averages throughout the planning period.

Uptake of heat pumps will have an impact on network capacity. However, diverse demands for energy hide heat pump growth, making this difficult to assess.

1.2.1.2 Capital investment

We have reported capital investment on our network over 10 years based on projects which have high priority. These projects have high priority because of capacity or security constraints. Some projects will be conditional on third-party decisions or developments such as consumer projects proceeding and resource consents for irrigation schemes. Appendix B at page 245 summarises Capex spent on these projects.

1.2.1.3 Investment in transmission assets

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

The Commerce Commission will approve or decline the pass through (recovery) of expenses for the 110 kV non-core transmission grid assets. These assets include the Lower Waitaki Valley circuits and the 110 kV line through to Timaru. These assets allow supply security and reliability to be preserved, and economic growth to continue throughout the region.

We will continue to deliver Transpower GXP capacity, grid support projects, and security requirements to current service levels. We also pass through the costs of maintaining service levels to consumers.

1.2.1.4 New technology

We assume no new technologies will be developed within the planning period, which will substitute for electricity network development. Distributed generation is viewed as an enabling technology for network support rather than network replacement.

1.2.1.5 NETcon is our preferred contractor

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 the Electricity Authority respectively. We will, during the period, ensure compliance with relevant Acts and Regulations.

1.2.1.7 Shareholder requirements

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

1.2.1.8 Year-on-year lines charge increases

In November 2012 the Commerce Commission reset the default price-quality path (DPP) that applies to all non-exempt electricity distribution businesses for 2013–14 and 2014–15. Under the reset, our price increases are capped at CPI + 11% in each year. The DPP requires us to increase prices by CPI + 11% or forgo revenue.

We will comply with the price path and will not increase prices higher than the price cap in either year. However, when we make a decision as to the appropriateness of pricing up to the price cap, we will consider both our obligation of an appropriate return to our shareholders and the equity of price increases on our consumers.

1.3 Period covered by the AMP

This AMP covers the period 1 April 2015 to 31 March 2025 and was approved by our board on the 25 March 2015. Our AMP was publicly disclosed by the 31 of March 2015 in accordance with the Electricity Distribution Information Disclosure Determination 2012.

1.4 Asset management systems

The Publically Available Standard 55 (PAS 55) is the internationally recognised standard for asset management. It defines an asset management system (AMS) as:

‘the set of collective governance, asset management policy, strategies, objectives, and plans that direct the lifecycle activities to be applied across the portfolio of assets in accordance with their criticalities, condition, performance and chosen risk profiles to achieve the organizational strategic plan’.

A description of our AMS is made throughout the document and includes descriptions on our strategies and policies as well as discussion 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 around 10,000 square kilometres, 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 at Figure 3.1 on page 29. Our asset base has a replacement value of over $150 million.

Electricity is delivered to the network via seven GXPs and one embedded generator. The network delivers some 752 GWh of energy a year, and had a half hour average coincident Maximum Demand of 127.1 MW recorded in February 2014. Energy consumption is up from the previous high of 750 GWh and the maximum demand is slightly up from 126.5 MW experienced in February 2013.

1.6 Service levels

We set levels of service in conjunction with the expectations of shareholders and consumers. Under the default price-quality path, the Commerce Commission sets quality standards, which determine reliability levels.

We discuss with consumers the price/quality trade-offs associated with levels of service and reliability, determined by the present network configuration. This provides an understanding of the level of network performance and helps to develop available options for consumer reliability expectations.

Formal consumer surveys, unsolicited correspondence, and direct conversations are used to determine consumer expectations. Previous consumer engagement across both large industrial and mass-market consumers revealed a high-level of support for keeping line charges the same in return for delivering similar levels of supply reliability.

1.7 Network development plans

We identify asset enhancement and development projects through consumer requests or network studies. Published Ministry of Economic Development guidelines 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 projection 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 readily developed. Unfortunately, electricity supply is only one reason considered when establishing large industrial loads, with priority given to transport corridors, land use restrictions, labour force, location of resource, etc.

Table 1.3 at page 10 provides the capital expenditure (Capex) forecast for the next 10 years. The figures are a summary of Appendix C at page 247. Costs are GST exclusive and in constant (real) dollars.

1.8 Life cycle asset management

Databases 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, or replacement of assets. The collection of further data improves the confidence level of asset condition and performance. Current hard copy plans and records are being transferred into the GIS's electronic format with pole assets field captured via GPS. Data entry for new or modified plant will be ongoing.

A review of the existing legacy databases is under way recommending an update to our overall AMS to improve efficiency, reliability, and usability.

1.9 Risk management

A risk management study based on AS/NZ 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 discover asset condition and regulatory compliance. These policies rank public and environmental safety as a top priority.

1.9.1 Health and safety

We uphold excellence in health and safety management. We will take all reasonable steps to ensure the work we do is safe to prevent any harm to people or damage to property.

Systems for managing health and safety have been adopted and are reviewed biannually. External contractors are required to disclose health and safety management programs, staff safety, and competency certification.

1.9.2 Emergency response and contingency planning

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

- emergency response procedures, as covered in detail in the 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 Lifeline Utilities Group. This Group promotes utility resilience and is involved with the review and development of disaster recovery plans for Civil Defence emergencies as required under the Civil Defence Emergency Act.

1.9.3 Environment

We will act in a manner required by both the Resource Management Act 1991 and the Hazardous Substances and New Organisms Act 1996.

1.10 Evaluation of performance

This AMP is used to measure asset management performance. Plans to maintain and improve the performance of asset management are based on the following:

- 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, upgrading, and extension of the network
- reviewing the asset management system with a view to updating and/or replacing its existing components
- actioning 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/real dollar terms.

1.10.1.1 Management of uncertainty

The statistics relating to performance against plan are taken from the last financial year summary details (2014–2015) to compare actual vs target results over a 12 month period in line with existing disclosure information.

There is an obvious degree of uncertainty in any predictions of the future and, accordingly, the AMP contains a certain level of uncertainty. The presence of several large electrical loads driven by turbulent commodity markets, current international economic crisis, public policy trends, and possible generation opportunities within our network demand profile, means the future is perhaps less certain than many other infrastructure businesses that have greater scale.

However, the management of present assets and asset condition creates a level of knowledge which can be utilised to appropriately plan and maintain a safe and reliable network, servicing our present consumer expectations into the future.

Accordingly, we have attached the following certainties to the timeframes of the AMP as shown in Table 1.1.

Table 1.1 AMP timeframe certainties

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

1.10.1.2 Use of nominal/constant dollar values

Both Capex and Opex values are expressed in constant dollar amounts (real dollars) unless specified. They have been adjusted using an inflator of 2%[4] 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, therefore, means that adjusting this amount by inflation each year would lead to Opex values that do not change for the next 10 years (in nominal terms).

1.10.1.3 Forecast variance for 2013/14

Table 1.2 shows the variance between forecast expenditure and actual expenditure for the 2013/14 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 Schedules 11a and 11b. A copy of the schedule in Excel format is available on our website.

[4] From most recent Treasury forecasts.

Table 1.2 Variance between actual expenditure and the previous year's forecast

Variance between actual expenditure and previous year forecasts	Forecast ('$000) 2013/14	Actual ('$000) 2013/14	Variance As a %
Capital expenditure			
Customer connection	2,703	3,701	+37
System growth	9,228	8,775	-5
Asset replacement and renewal	3,524	2,688	-24
Asset relocations	0	265	+100
Reliability, safety, and environment	5,841	2,585	-56
Subtotal—capital expenditure on network assets	*21,295*	*18,015*	-15
Operating expenditure			
Service interruptions and emergencies	1,485	1,979	+33
Vegetation management	123	110	-10
Routine and corrective maintenance and inspection	2,946	3,232	+10
Asset replacement and renewal	798	572	-28
Subtotal—operating expenditure on asset management	*5,352*	*5,893*	+10
Total direct expenditure on asset management	**26,647**	**23,908**	**+10**

Table 1.3 AMP forecast expenditure 2015 to 2025 (in $'000 and constant prices)

Expenditure	Actual	Forecast										
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Capital												
Customer connection	3,701	2,890	2,925	2,925	2,900	2,925	2,875	2,475	2,425	2,400	2,400	2,350
System growth	8,775	1,390	3,645	3,830	4,180	730	620	630	620	520	480	450
Asset replacement and renewal	2,688	3,920	5,039	6,203	5,194	4,150	3,642	3,642	3,842	3,630	3,510	3,310
Asset relocations	265	-	105	-	-	-	-	-	-	-	-	-
Reliability, safety, and environment	2,585	1,740	1,953	1,240	990	940	820	820	820	785	820	760
Subtotal—network Capex	**18,015**	**9,940**	**13,667**	**14,198**	**13,264**	**8,745**	**7,957**	**7,567**	**7,707**	**7,335**	**7,210**	**6,870**
Capex on non-network assets	1,268	942	5,887	3,955	3,380	3,605	450	355	425	380	380	380
Total Capex	**19,283**	**10,882**	**19,554**	**18,153**	**16,644**	**12,350**	**8,407**	**7,922**	**8,132**	**7,715**	**7,590**	**7,250**
Operating												
Service interruptions and emergencies	1,979	1,895	1,421	1,391	1,366	1,339	1,313	1,287	1,262	1,237	1,237	1,237
Vegetation management	110	94	490	480	471	462	453	444	435	427	427	427
Routine and corrective maintenance	3,232	2,764	2,746	2,687	2,639	2,587	2,537	2,487	2,438	2,390	2,390	2,390
Asset replacement and renewal	572	595	586	573	563	552	541	531	520	510	510	510
Subtotal—network Opex	**5,893**	**5,348**	**5,243**	**5,130**	**5,040**	**4,941**	**4,844**	**4,749**	**4,656**	**4,564**	**4,564**	**4,564**
Opex on non-network assets	9,379	9,079	8,165	8,488	8,629	8,601	8,545	8,481	8,449	8,422	8,400	8,382
Total Opex	**15,272**	**14,427**	**13,408**	**13,618**	**13,669**	**13,542**	**13,389**	**13,230**	**13,105**	**12,986**	**12,964**	**12,946**
Total Expenditure on assets	**34,554**	**25,309**	**35,962**	**31,771**	**30,313**	**25,892**	**21,796**	**21,968**	**21,152**	**20,701**	**20,554**	**20,196**

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

2. Building blocks of the Asset Management Plan

2.1 Introduction

This chapter 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 that 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 lifecycles from the proposal phase to de-commissioning
- identify risks and have appropriate processes in place to mitigate those risks
- make appropriate provision for funding the stages of the asset lifecycle
- make informed decisions with systematic and structured frameworks at each level within the business
- have robust information about 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 not a detailed description of our assets, but a description of the policies, strategies, plans, and resources we use to manage our 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 do this 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 out of communications with our key stakeholders.

Our strategic goals and objectives 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, publicly and socially responsible company.

2.4.1 Stakeholder engagement

Stakeholder engagement is essential for our decision making. Communicating our AMP to stakeholders forms part of our engagement process.

Table 2.1 describes our stakeholder interests and how we accommodate those interests.

Table 2.1 Identification and management of stakeholder expectations

Stakeholder	Identification and management of expectations	Key interests
Shareholders: Lines Trust South Canterbury and district councils	Through approval and/or required 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.	• Lines 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 • Lines 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.
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.

2.4.1.1 Accommodating common stakeholder interests

Table 2.2 describes how we accommodate common stakeholder interests.

Table 2.2 Accommodating 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.
Price	Price is a key means signalling underlying costs. Getting prices wrong has economic implications for both us and our stakeholders.	Failure to gather sufficient revenue to fund reliable assets will interfere with consumers' business 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. In this period we intend to scope asset management systems in which to more effectively record our assets.

2.4.1.2 Managing conflicting interests

Conflicting stakeholder interests are managed by taking account of how they impact on the following 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. These documents include the *Statement of Corporate Intent*, *Strategic Management Plan*, *Asset Management Plan*, *Annual Works Plans* (for both Capex and Opex plans), and the *Alpine Energy Safety Management System* related documents.

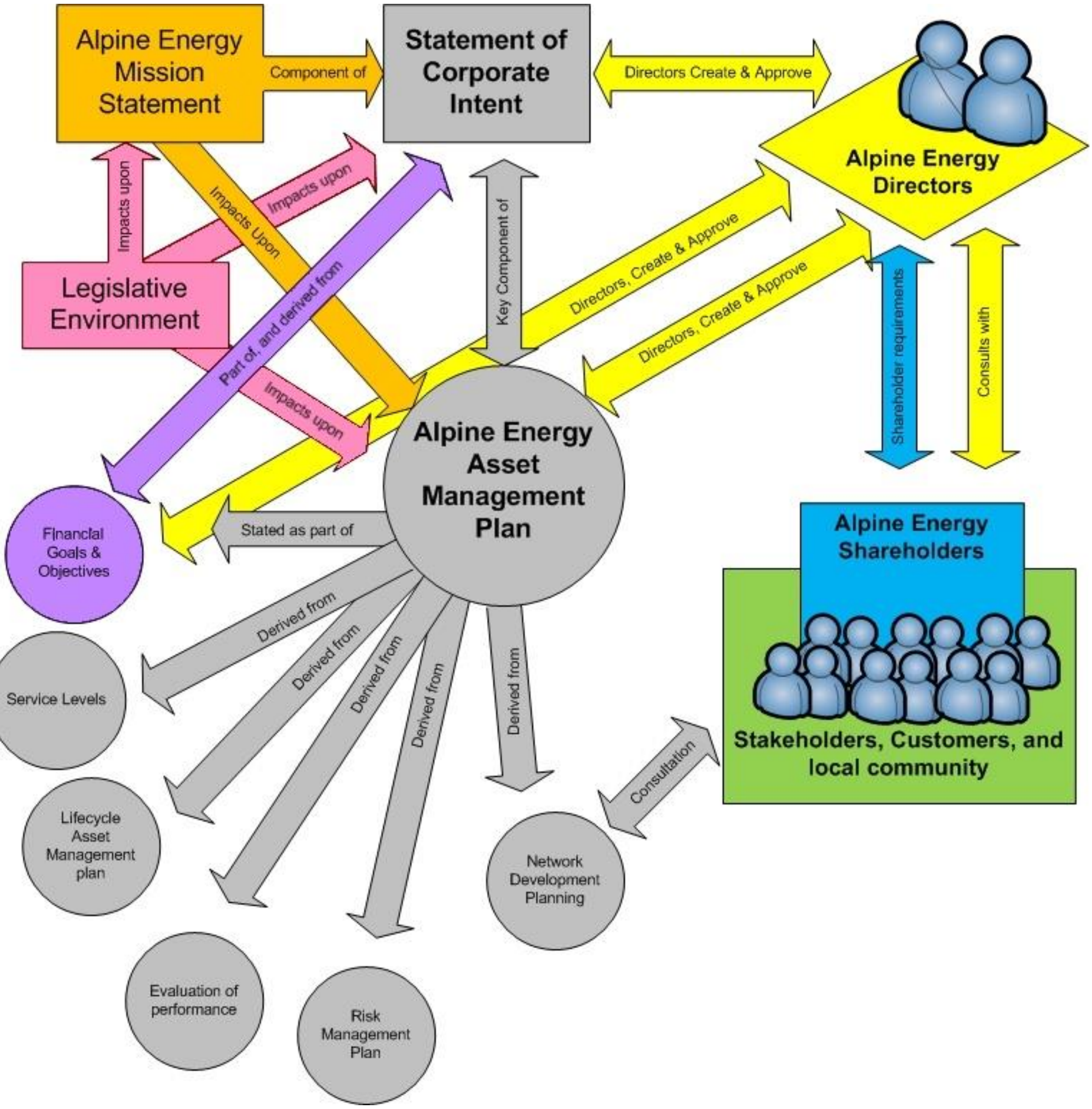
Figure 2.2 shows the interaction of our key planning documents with our strategic goals and objectives.

2.5.1 Statement of Corporate Intent

Our Statement of Corporate Intent (SCI) sets out our strategy for delivering our goals and objectives over the next three years (i.e. 1 April 2015 to 31 March 2018) 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 having accounting policies that support compliance
- setting financial and operating 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.

Figure 2.1 Interaction of key processes and entities



2.5.2 Asset management strategy

Our asset management strategy describes the asset management processes (actions) that we undertake to achieve our strategic goals and objectives. At present our strategy is not a formal document; instead, it is inherent throughout our AMP. Please see section 8.3—Continuous improvements to our asset management system at page 227, for details on how we intend to formalise an asset management strategy.

2.5.3 Annual works plan

Our works plan ensures that our activities and projects are prioritised and aligned with our goals and objectives for the year in question. It reflects on existing projects and adjusts for recent commercial and operational issues, while also contributing to long term planning.

The works plan also details how a project should be implemented. Projects in the works plan reflect projects described in our 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 at page 204.

2.6 Planning assumptions

Our planning takes into account assumptions and uncertainty about the social, economic, and political environment in which we work. These 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 requirements[5] require us to provide information on the state of our asset maturity, including our systems and processes. This assessment has identified that our systems and processes for life cycle asset management need to be further established and developed. A summary of this 'self-assessment' is found in chapter 8—Asset Management Maturity Assessment. Details can be found in Table 8.2.

2.7.1 Key systems and processes

The present state of our AMS and processes is discussed below. Further detail on Life Cycle Asset Management is found in chapter 6. We are enhancing our systems and processes. For further information please refer to chapter 8—Asset Management Maturity Assessment.

[5] Commerce Commission, Electricity Distribution Information Disclosure Determination 2012, Decision No. NZCC 22, 1 October 2012.

2.7.1.1 *Information technology for asset management*

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

Table 2.3 Description of information technology databases

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

2.7.1.2 *Operating processes and systems*

To ensure safety to personnel, public, and plant, our operating processes and systems 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 and network control and operating procedures.

2.7.1.3 *Maintenance processes and systems*

Our maintenance processes are based on the manufacturer's specifications and maintenance requirements. Generally, asset condition is based on age and condition. The assessment will determine whether the asset is replaced, refurbished, maintained, or recorded as being in 'good condition' and left until the next scheduled inspection.

Present maintenance processes and systems are a combination of manual and paper-based systems (i.e. maintenance and test cards, test reports, and spread sheet schedules) supplemented by 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—a wholly owned subsidiary of the Alpine Energy Limited group. NETcon use detailed planning maintenance schedules for our substations and plant. The schedules are held and maintained by NETcon on our behalf.

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 assessments indicate that an existing asset is at risk, the item is scheduled for renewal. Often, assets will age or exhibit deterioration at different rates. A decision then needs to be made in regard to replacing an entire series or individual assets on successive visits. The economics of either approach needs to be evaluated on a case-by-case basis, and must also account for the risk of extending the assets' service life.

Inspection programs for overhead lines are routinely undertaken. The remaining strength of the support pole is assessed to determine 'end of life' so as poles are replaced 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 these inspections is collated, reviewed, assessed, and used by us to inform our planning decisions.

2.7.1.5 Upgrading or extension processes and systems

Load growth often reduces capacity headroom. Our forecasting and network modelling tools indicate when feeders are likely to need to be supported by capacitors or regulators, or reconducted with larger conductor; or whether zone substation transformer capacity needs to be increased.

Network modelling software programs like ETap provide a valuable tool for forecasting when up-sizing may be required due to voltage performance limits being reached on substation feeders.

For further information on our planning processes please refer to section 5.2—The planning process at the strategic level.

2.7.1.6 Reliability enhancement processes and systems

We review faults and investigate causes to provide insight into 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 *Security of Supply Standards* (EEA Standards Guide). We take into account our network conditions when using the EEA Standards Guide to evaluate for risk calculations and adjust, where appropriate, for:

- local geography

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

The adjustment will produce different security of supply levels for individual sites or installations from those produced by the EEA Guide, if applied mechanistically.

Each year we review our 10 worst performing feeders to determine the supply failure mode and what remedy can be implemented to reduce reoccurrence. Remedies include: building a new feeder, splitting urban areas from rural areas to avoid remote rural faults affecting urban areas, and installing additional reclosers to reduce the number of consumers affected by a single fault.

2.7.1.7 Customer connection processes and systems

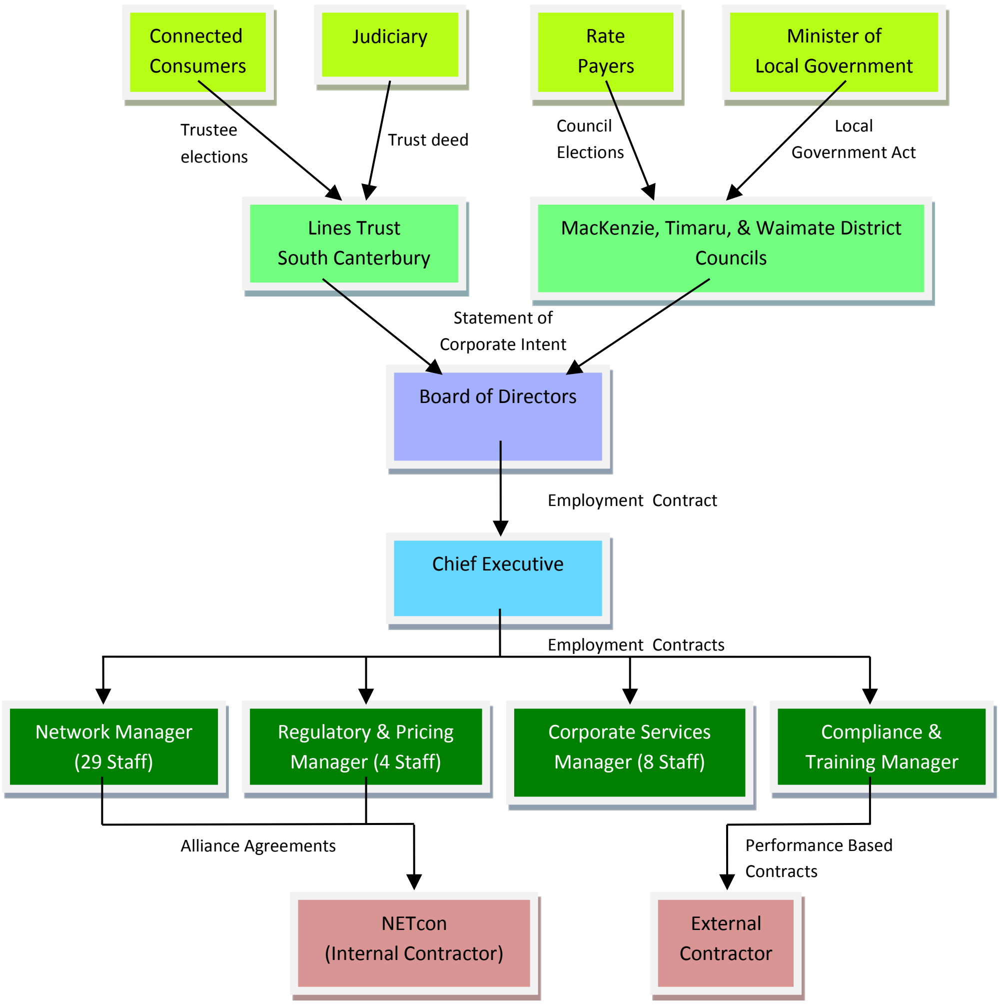
Customer applications for connection to our network are processed through a standard system, with contractor quotes used to determine connection price.

Photograph 2.1 NETcon is our preferred contractor

2.8 Accountabilities for asset management

Figure 2.2 shows our asset management accountabilities and mechanisms.

Figure 2.2 Accountabilities for asset management



Our accountabilities for asset management are discussed in detail in the following sections.

2.8.1 Accountability at ownership level

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

- Lines Trust South Canterbury - 40%
- Mackenzie District Council (MDC) - 4.96%
- Timaru District Council (TDC) - 47.5%
- Waimate District Council (WDC) - 7.54%.

This means we are owned by the community we serve.

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 their ratepayers through the local body election process and also to the Minister of Local Government under the *Local Government Act 2002*.

2.8.2 Accountability at governance level

Our directors are accountable to shareholders through our Statement of Corporate Intent (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 targets to meet SCI goals and objectives.

2.8.4 Accountability at management level

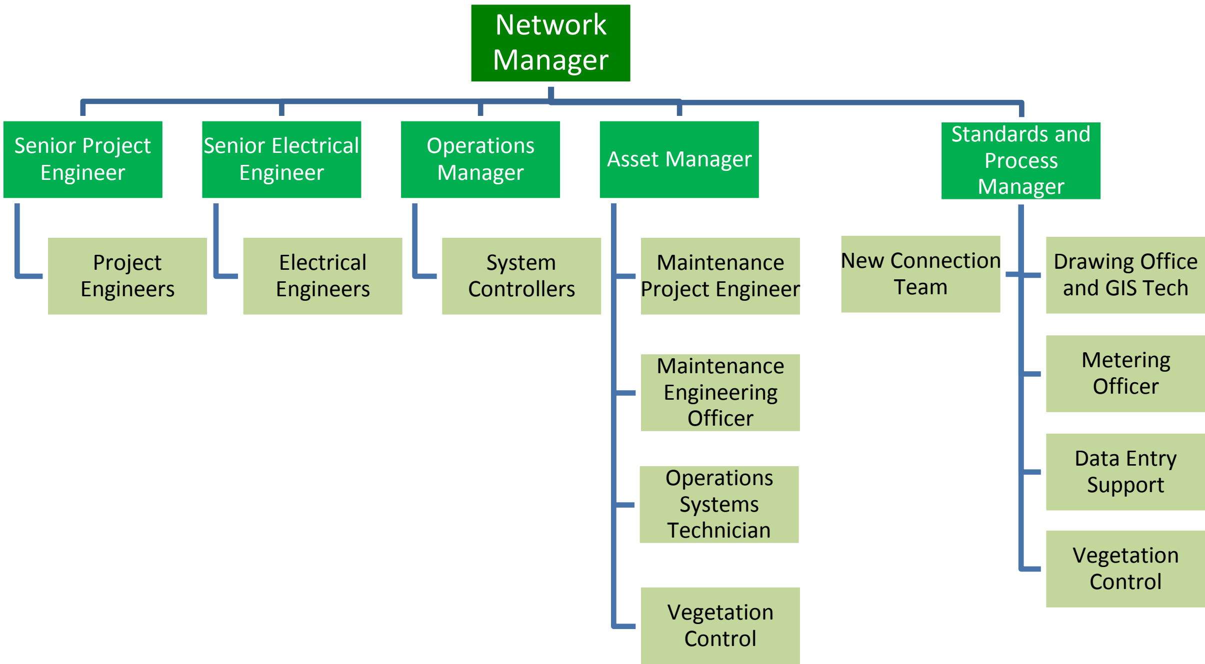
Accountability for asset management ultimately lies with our Network Manager who has delegated accountability to five second-tier managers.

- Senior Project Engineer—accountable for overhead line design.
- Senior Electrical Engineer—accountable for the development of new network assets through long-term planning such as capacity, security, and asset configuration.
- Asset Manager—accountable for managing the lifecycle activities of existing assets.
- Operations Manager—accountable for the management of the day-to-day running of the network including control, operating, reporting, and dispatch of switching and fault response work to contractors.
- Process and Standards Manager—accountable for our standards and processes, New Connections and Drawing Office (including GIS) teams, and legacy metering.

There is a strong team focus between the operations, asset, and network managers to balance budgets and co-ordinate maintenance, renewal, and operation of the asset portfolio as directed under the framework of the AMP and business strategies.

Figure 2.3 shows our areas of accountability for asset management at the network level.

Figure 2.3 Accountabilities of asset management at network level



2.8.5 Accountability of our contractors

2.8.5.1 Contractor accountability

NETcon is accountable through an Alliance Agreement as our preferred contractor for capital and maintenance services on our network. NETcon has approximately 70 staff that are able to provide a scalable resource for us during adverse weather events or large projects via relationships we have under Mutual Aid Agreements 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 an Alliance Agreement).

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

Specialist jobs are undertaken by outside contractors who quote to a scope or specification, on a competitive basis (for example, some engineering design (by consultants), civil design, and construction 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 of Directors 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 Capex projects i.e. over $450,000.

Directors meetings are typically held once every two months.

The budget detail and review of the AMP are driven by the asset and network managers. Specialist engineering knowledge and information is provided from the Engineering Department under leadership of the Senior Electrical Engineer.

The approval of projects by the Board of Directors is achieved by means of the AMP and Capex instruments.

2.8.6.1 Network Group

The Network Group consists of the following four teams:

- Operations
- Asset Management
- Engineering
- Process and Standards.

Operations Team

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 provides valuable feedback as part of the asset management process by providing practical safety, operation, and asset performance/condition information that helps refine assets and procedures.

Asset Management Team

The Asset Management Team is responsible for all existing primary and secondary electrical assets. The team's responsibility extends to the reliability of the network, the technology on the network, and the secondary systems such as SCADA as well as vegetation management.

Engineering Team

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

Process and Standards Team

The Process and Standards Team is responsible for the design and commercial management of new connections and extensions to the network. The team meets this responsibility through the management, creation, and updating of network drawings, GIS and other asset database entries, and the management and preparation of job packs for issue to and return from contractors.

The Process and Standards Team has been the driver behind business process mapping and scoping of the proposed new asset management system.

2.8.6.2 Corporate Services Department

The Corporate Services Department manages the financial, accounting, and ICT system functions. The department provides contract and financial analysis, and expertise for items outside the network's routine work, such as business development.

2.8.6.3 Regulatory and Pricing Department

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

2.8.6.4 Compliance and Training Department

The Compliance and Training Department manages compliance and training matters, as well as our human resource functions. The department ensures that all contractors working on our network are authorised to access the network and complete their work to the required standards. The Compliance and Training Department champions our health and safety culture through promotion of best practice and continuous improvement of safety on the network.

3. Network Assets

3.1 Introduction

This chapter describes the key drivers which influence energy demand in our area of operations and the design and configuration of our assets to meet this demand.

Chapter 5—Network Development Planning describes how these same factors are taken into account during our network development planning.

3.2 An overview of our area of operations

Our network stretches over 10,000 square kilometres, 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 supply boundary, as shown in Figure 3.1.

Please note, the Hakataramea and high country bounding on Aviemore and Benmore lakes are part of Network Waitaki Limited (NWL).

The three district councils—MDC, TDC, and WDC—provide infrastructure assets across the area and are also three of the four shareholders.

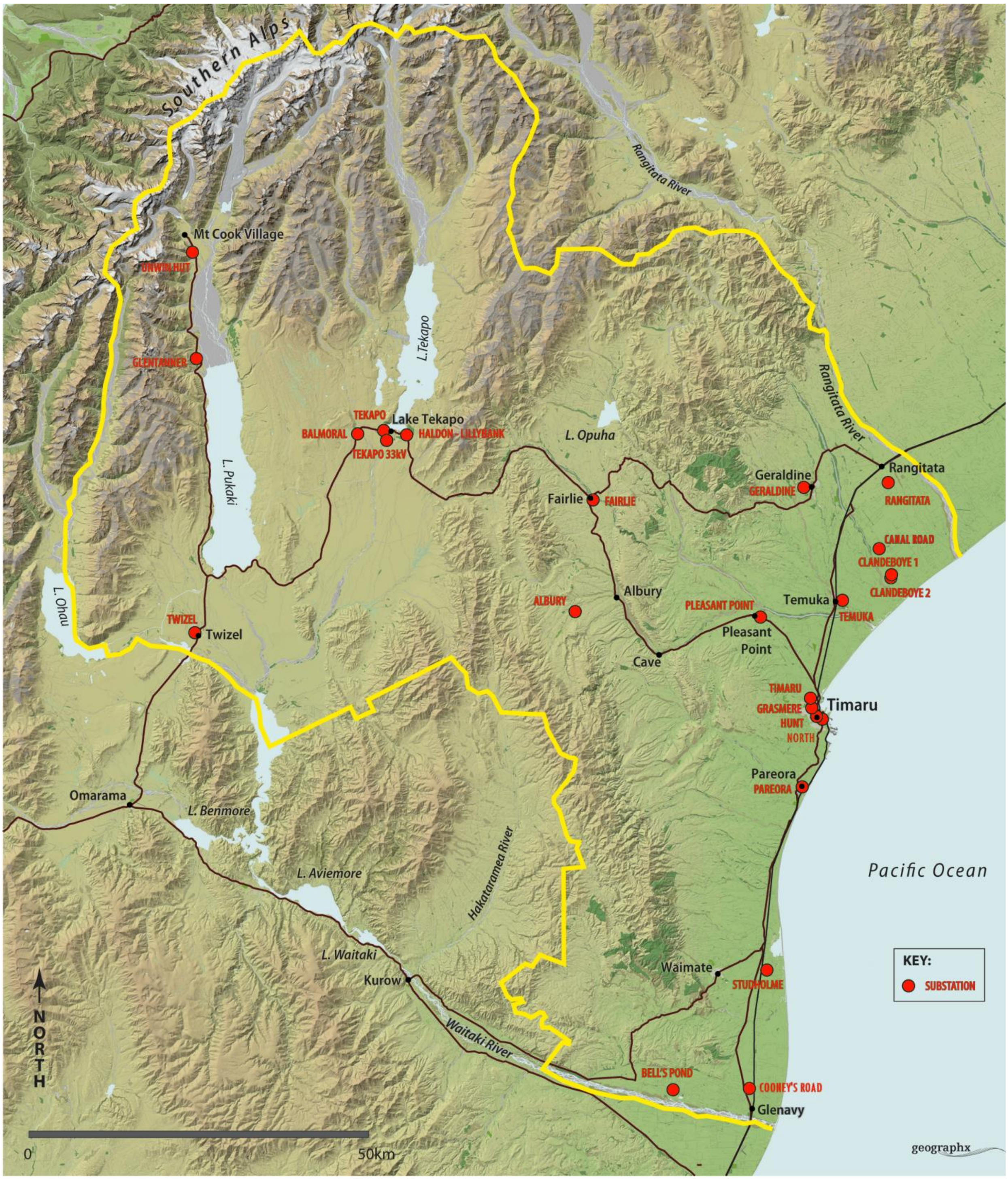
The population figures for the three council districts for 2013 (including population growth from 1996 to 2013) are listed in Table 3.1.

Table 3.1 Population growth (source: Statistics NZ)

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 above shows that growth in the population is small. Most of this growth occurs in urban areas while most of the growth in load is from the irrigation requirements of dairy farming. This is further described in the next section.

Figure 3.1 Our area of supply



Timaru

The majority of consumers live in Timaru City situated on the East Coast, with about 13,500 of our 30,576 consumers living in or near the Timaru area. 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 works, a container, timber export, and bulk cement terminal port, a brewery, wool scour, and food processing industries. Residential growth is steady, with higher demand from new industrial development.

The second largest population group lives at Temuka, 20 km north of Timaru. This area is surrounded by rural plains used for farming. Our largest customer, Fonterra (30 MW instantaneous maximum demand), operates a milk processing factory at Clandeboye and continues to expand its operation while stimulating development in the local economy. The areas north of Temuka, and up to the Rangitata River, continue to see extensive development in cropping and dairying with supporting irrigation.

Geraldine, Peel Forest, Pleasant Point, and Pareora are rural support towns with stable populations that are serviced by the TDC.

Mackenzie

The Mackenzie area is situated 40 km west of Timaru and extends to the southern divide. This is an alpine area requiring assets to be strengthened for snow and wind loading. MDC is located in Fairlie and administers 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 burgeoning subdivision and hotel accommodation development.

Twizel is the operational centre for Meridian's power generation assets. Genesis also has generation assets at Tekapo (Tekapo A and B). Growth is predicted to increase in the Tekapo and Twizel areas, particularly with plans for further irrigation development in the Twizel district, and a new retail development in Tekapo Township planned for 2015.

Waimate

The Waimate area is administered by the WDC and is the southern area in South Canterbury. Sizeable irrigation development has occurred in this area, serving to stabilise the population of the Waimate Township.

3.2.1 Load growth in our network

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

The total energy consumed has been in the region of 700 GWh to 800 GWh over the last four years, varying from one year to the next according to wet or dry irrigation seasons, and/or severe or mild winters.

The anytime maximum demand (AMD) is presently 127.1 MW[6]. Growth in AMD has been approximately 2.38% per year over the last 17 years.

3.2.2 Significant economic and environmental influences

The key economic activities in our area of operations strongly influence the configuration of our network, particularly activities that stem from primary industries.

There has been significant growth in dairy farming and dairy processing which brings an increased demand for load for irrigation purposes, as well as a need to supply the recently commissioned dairy factory in Glenavy and other established dairy plants in Studholme and Clandeboye. Other large industrial customers, such as Alliance Smithfield and Silver Ferns Farms meat processing plants, have a substantial effect on the network.

Altogether the viability of arable farming and the availability of water will have a significant impact on the economy and a direct impact on the configuration of the network.

The port operations at PrimePort Timaru continue to be an important element in the local economy. Although of late Fonterra, as well as some shipping companies, had preferred to use Lyttleton Port of Christchurch, the recent change in management of PrimePort Timaru has seen a resurgence in local container operations. In addition, Holcim cement recently decided to use PrimePort Timaru, a partner of the Port of Tauranga, for movement of its bulk cement in the South Island and beyond.

Photograph 3.1 PrimePort Timaru

[6] As at December 2014.

3.2.2.1 Peak loading

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

Winter peak demand occurs for TIM and TKA GXPs. However, other areas, such as Fairlie and Geraldine, also have significant demands for load during the winter months when temperatures can drop below -10^{o}C.

Winter load demand may rise due to stronger regulation around air quality and particulate matter which may restrict the use of fires for heating. This will place a greater demand on the network to service the load requirements of heat pumps, etc.

3.2.2.2 Large customers

Our large customers can have a significant impact on the design of the network. Our top five customers, based on demand, are described at Table 3.2.

Photograph 3.2 CNR substation with ODL dairy factory behind

Table 3.2 Top five large customers

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 2 x 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	10 x 11 kV RMUs (one switching and two spare). 7 x 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. 15 x 11 kV RMUs (3 spare). 12 x 11/0.4 kV distribution transformers.

Impact on the network	Significant, but transformers and switchgear could be reused over time elsewhere in the network.
Silver Fern Farms	
Location	**Pareora**
Dedicated assets	Two existing dedicated 11 kV CB feeders to customer-owned switchgear at works.
Impact on the network	Significant, with growing irrigation load in the Pareora area and provision needed to back up the supply to the south of Timaru.

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 at Table 3.3.

Table 3.3 GXP energy and maximum demand figures

GXP area	Asset utilisation (GWh)	Max demand[1] (MW)	Load factor (F=W/(Pmax.T))	Transpower capacity utilisation (Pmax/Ptxfr)	Long-term growth trend (based on 17 year historic)
ABY	8.797	4.255	0.24	85%	1.44%
BPD	19.934	7.380	0.31	37%	4.83%*
STU	59.226	11.430	0.59	52%	3.20%*
TKA	16.716	3.890	0.49	39%	3.36%
TMK	268.946	51.294	0.60	50%	3.71%
TIM	351.585	63.434	0.63	67%	0.69%
TWZ	12.733	3.004	0.48	8%[2]	2.32%
Exported	-19.500				
Generation	33.639				
Total	**752.076**	**127.1**			**2.38%**

Note 1: the individual GXP's MDs are not coincident with either each other or the total system MD.
Note 2: the TWZ GXP is shared by two other customers; their utilisation of the asset is not added to ours.

Inspection of the TIM and TMK GXP maximum demand trends appears to show that the maximum demands for these two GXPs have plateaued over the last six years.

Forecast growth in demand has maximum demand increasing to 130 MW in 2014-15 and to 146 MW in 2019–20, assuming a constant growth rate of 2.38% over a six year period. More information on our demand forecasts can be found at Schedule 12c: Demand Forecast at Appendix I.

3.3 Network configuration

This section describes our network assets in relation to Transpower's GXPs. A brief summary is offered for GXPs, zone substations, and sub-transmission assets (more detail can be found in the Major Network Asset Management Plan). A summary of the condition of these assets is found in the Commerce Commission's Schedule 12a: Asset Condition. A copy of the schedules is available on our website.

It should be noted that, on limited occasions, network asset age profile data (below)[7] is shown to have inconsistencies. We address these issues on a case-by-case basis and through the enhancement of our AMS ICT systems. For more information on the latter, see section 8.3—Continuous improvements to our asset management system.

3.3.1.1 Historical constraints on our network

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

- The compact MED area was 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 110/33/11 kV supply in the adjacent Temuka and Geraldine rural areas means that the historical areas cannot be easily and safely meshed to improve security of supply.
- There are areas of supply at the boundary of the previous businesses that can be improved by greater integration of the assets of the two legacy networks (for example, by upgrading 11 kV lines and cables and introducing additional, or upgraded, points of connection between the two networks).

[7] The age profiles 11 kV CBs, ripple plant, and LV cables are presently under review.

3.3.2 Bulk supply configuration

Detailed information on Transpower's GXPs is found in the Major Network Asset Management Plan. A summary of GXP asset information is given in this section.

Figure 3.2 shows the configuration of the GXPs from a transmission perspective.

Figure 3.2 Transpower GXPs

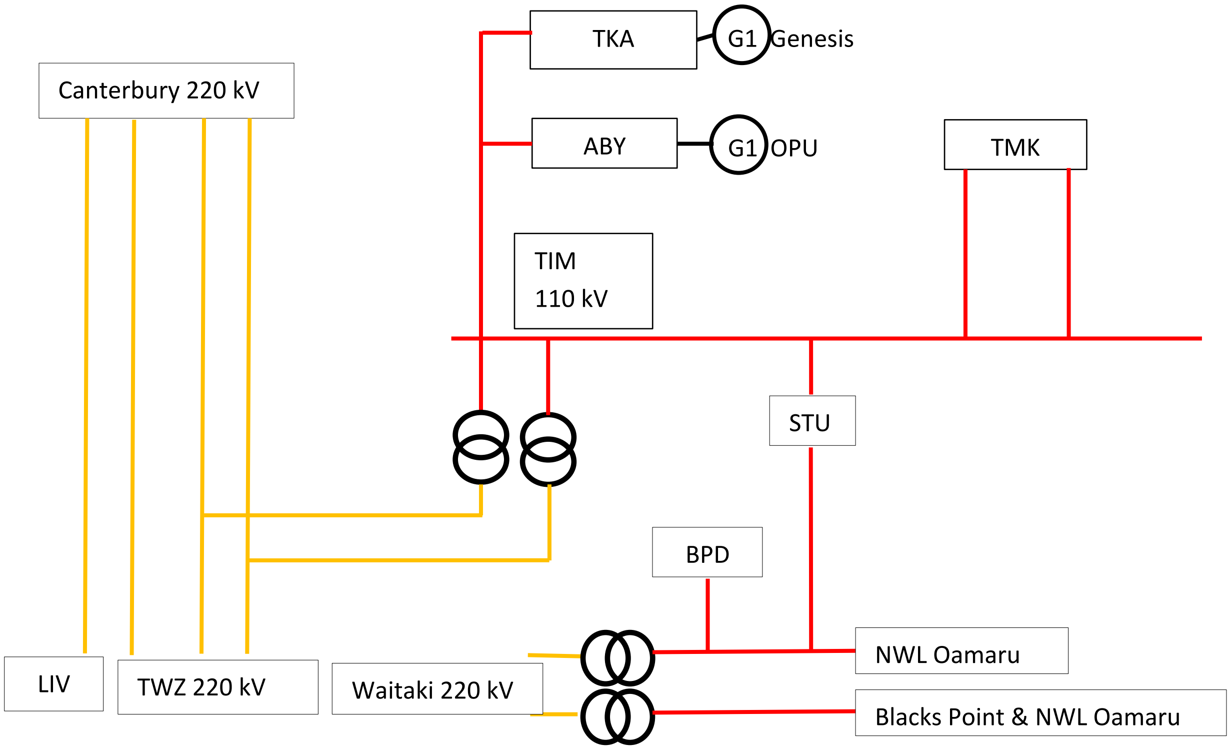


Table 3.4 summarises key GXP details.

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

GXP	GXP voltage(s), transmission	GXP supply 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	7.4 MW	
STU	110 kV	11 kV	24 MVA	12 MVA	11.4 MW	
TKA	110 kV	33 kV	6.7 MVA	0	3.9 MW	
TMK	110 kV	33 kV	122 MVA	61 MVA	51.3 MW	
TIM	220 kV, 110 kV	11 kV	141 MVA	94 MVA	63.4 MW	
TWZ	220 kV	33 kV	40 MVA	20 MVA	3.0 MW	

****Note:** GXP capacity source: TP51989/35.dwg, Sep 14.*

3.3.3 Assets by category

Our assets can be grouped as detailed in Figure 3.3.

Figure 3.3 Assets by category

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).

3.3.4 Sub-transmission and zone substation configuration

Detailed information on sub-transmission and substation assets can be found in the Major Network Asset Management Plan. This section provides a summary of this information.

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

Table 3.5 Sub-transmission and zone substation configuration

GXP	Sub-transmission and zone substation configuration
ABY	ABY 11/33 kV step-up substation, supplying single circuit 33 kV line to FLE, and from there the 33 kV line to the privately owned OPU Power Station. Two 11 kV feeders.
BPD	110/33/11 kV zone substation with three 11 kV feeders.
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 circuit to 33/11 kV TEK zone substation with four 11 kV feeders, and 33 kV 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 circuits to TIM 2 x 11/33 kV step-up substation, supplying one single 33 kV line to PLP, and two predominantly single circuit and some double 33 kV 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 circuit to 33/11 kV TVS substation with four 11 kV feeders.

Table 3.6 provides a breakdown of the peak load installed capacity and security of supply classification for each of our substations. A summary of the condition of assets is found in the Commerce Commission's Schedule 12a Asset Condition. A copy of the schedules in Excel format is available on our website.

Table 3.6 Capacity of substation major assets

Existing zone substation	Current peak load (MVA)	Installed firm capacity (MVA)	Security of supply classification (type)	Transfer capacity (MVA)
ABY	4.30	0.00	N	2.5
BML	0.15	0.00	N	0
BPD	7.40	0.00	N	3.5
CD1	16.00	20.00	N-1	0
CD2	14.00	25.00	N-1	0
CNR	0.00	0.00	N	1.8/0.8/0.6*
FLE	2.40	0.00	N	0.5
GLD	6.10	0.00	N	4
GTN	0.20	0.00	N	0
HLB	0.30	0.00	N	0
PAR	8.70	15.00	N-1	4
PLP	4.70	0.00	N	2.5
RGA	9.80	15.00	N-1	4
STU	11.40	11.00	N-1	3.5
TEK	2.60	0.00	N	0
TMK	11.70	25.00	N-1	4
TIM 11/33	12.30	25.00	N-1	0
TVS	3.00	3.00	N-1	0
UHT	1.10	0.00	N	0

**NOTE: CNR sub has three transfer capacities: winter/summer/BPD off-load.*

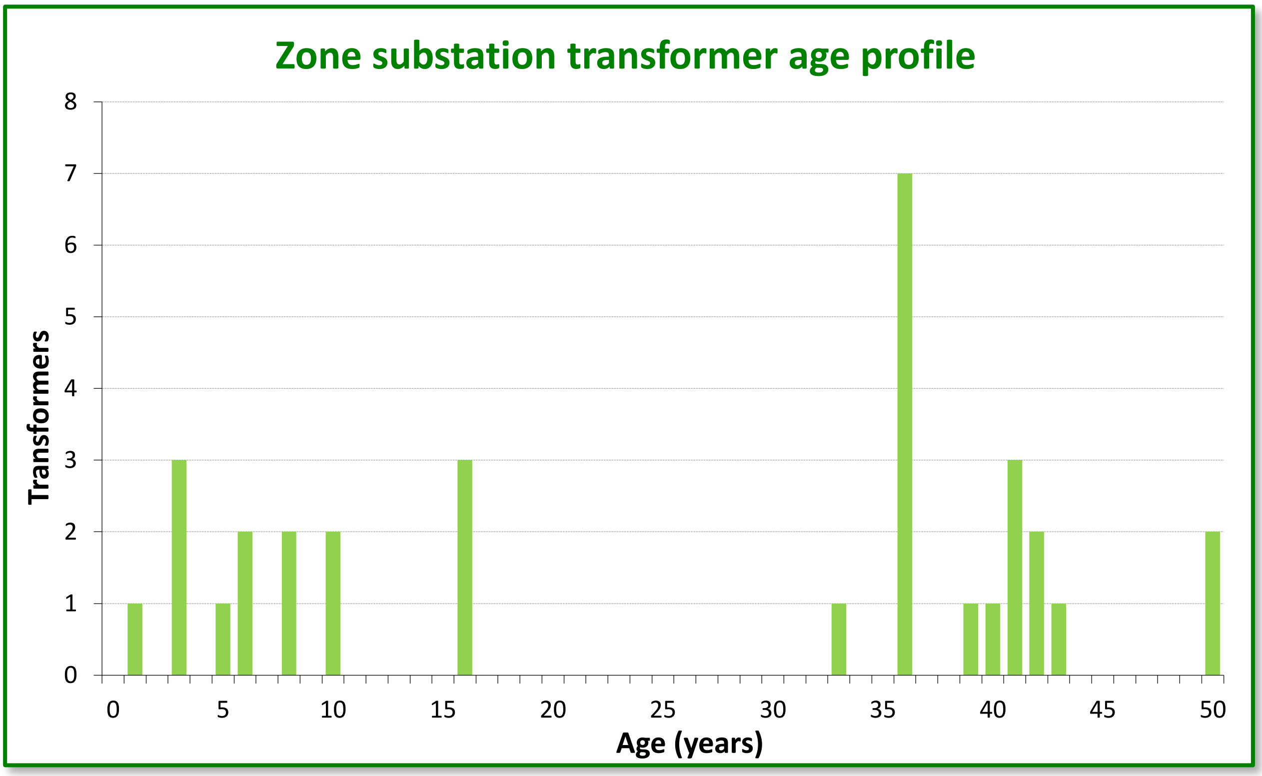
3.3.5 Major zone substation assets

The following section describes the age and condition of substation transformers, as well as 33 kV and 11 kV substation switchgear and ripple injection plants. For greater detail on these assets please refer to the Major Network Asset Management Plan.

Zone substations convert sub-transmission voltage to distribution voltage. In our case this is typically 33 kV to 11 kV.

The age profile of zone substation transformers provided in Figure 3.4 shows that, while some transformers have been replaced in the last 10 years, the majority of our transformers date back prior to 1980 and four to the 1960s.

Figure 3.4 Zone substation age profile



The zone substation transformer population is generally in good condition.

The older transformers are at generally lower loaded sites and have been refurbished mid-life to ensure they reach their expected life of 50 years of service. Some further minor refurbishment will be undertaken as some of these older transformers are replaced and relocated.

The two 5/6.25 MVA transformers released from PAR sub in October 2012 were manufactured in 1973 and 1977. These 36 and 40 year old transformers were refurbished and returned to Washdyke Depot in 2013–14 for storage until they are able to be reused at FLE and TEK substations to upgrade the 3 MVA units. Following the successful refurbishment they should have another 20+ years of useful life at those two substations.

The 5/6.25/9 MVA transformer released from RGA in September 2012 requires its conservator to be enlarged due to an oil expansion contraction issue when fully loaded. This 1982 unit is planned to be refurbished in 2014–15 at the same time that it has its conservator upgraded. The manufacturer is preparing a proposal for this work.

Four new 9/15 MVA transformer sets were purchased (three in 2011), installed, and commissioned at PAR and RGA in 2012.

Photograph 3.3 RGA transformer

The Major Network Asset Management Plan contains detailed information on the zone substation developments planned over the next few years.

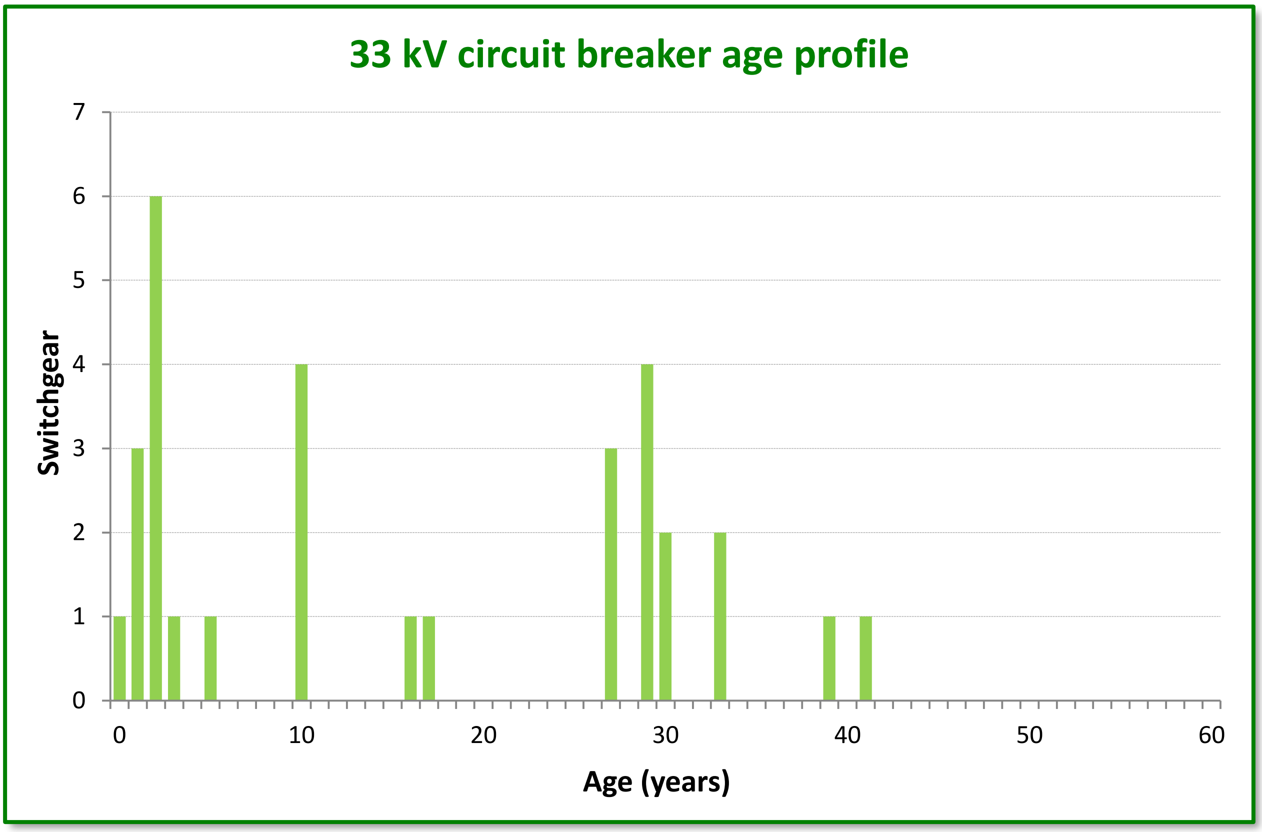
In 2014 another 33/11 kV 9/15 MVA power transformer was procured and installed at CNR Substation for the new ODL dairy factory near Glenavy.

3.3.5.1 Switchgear

Figure 3.5 shows the age profile of 33 kV switchgear. The age of switchgear varies from 0 to 40 years, with 43% of the network 33 kV switchgear older than 25 years.

In 2014, one 110 kV SF6 outdoor CB (operated at 33 kV) and a switchboard of 11 kV vacuum switchgear was procured and installed at CNR substation for the new ODL Dairy Factory near Glenavy.

Figure 3.5 33 kV switchgear age profile



There are 30 x 33 kV circuit breakers and reclosers on our network. The majority are situated within zone substation compounds to protect zone transformers or sub-transmission lines. Each circuit breaker has associated protection relays and/or controller.

Most of the 33 kV circuit breakers and reclosers have vacuum mechanisms contained in bulk oil tanks. Three 33 kV circuit breakers are due for replacement during the period of the plan.

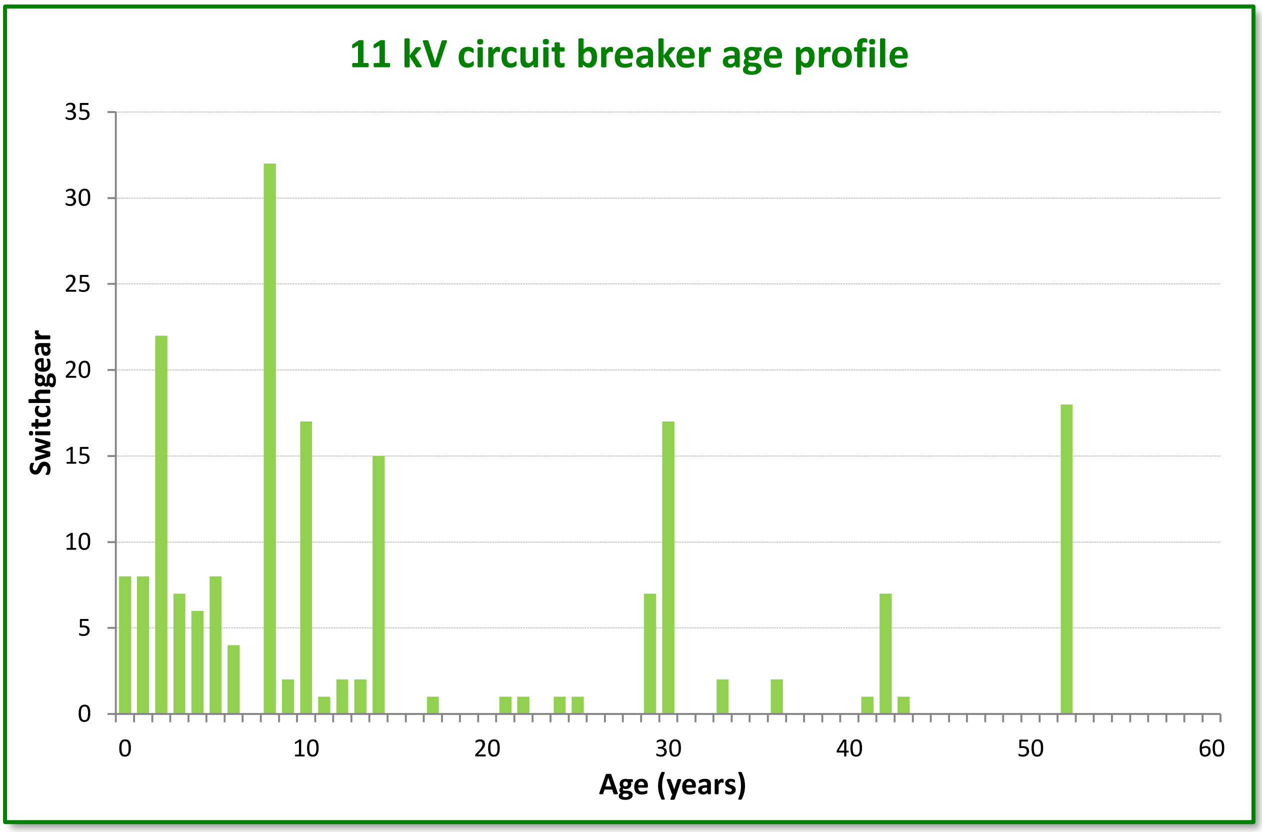
The six new 33 kV vacuum CBs commissioned at PAR sub in 2012 are indoor type with SF_6 insulated chambers. Two old vacuum/oil reclosers were decommissioned and one is available to be redeployed.

The two new 33 kV SF_6 puffer type CBs commissioned at RGA sub 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 3.6 gives an indication of the age of the indoor 11 kV circuit breakers on the HV network. Earlier circuit breakers are of the bulk oil variety and were installed between 1962 and 1985. More recently vacuum type circuit breakers have been installed and account for the circuit breaker population after 1985. They are being used for new installations, and where bulk oil circuit breakers are being replaced.

Figure 3.6 Indoor 11 kV switchgear age profile



The suites of 11 kV indoor circuit breakers at GRM (1962) were replaced with new VCB boards (20 VCBs) in the spring and summer of 2012–13 using the existing, but upgraded, building.

Ideally we would inspect circuit breakers in line with manufacturer's recommendations but, due to a lack of trained technicians nationally, there is pressure to meet this target. Following maintenance, circuit breakers are only returned to service if the condition guarantees sufficient remaining life for the next maintenance period.

The maintenance database allows circuit breakers that have not been serviced within the manufacturer's recommendations to be flagged. Flagged breakers are inspected when possible.

Battery banks installed at zone substations have now been replaced with sealed recombinant type batteries which have a higher initial cost but give a far greater life (up to 10 years but are typically changed out at 7 years) and also have 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 tested regularly; if the tests determine the asset is reaching the end of its reliable service life, then it will be programmed for change-out.

The condition of existing zone substation control and alarms varies considerably throughout the system, and is generally dependent on the age of the substation.

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 maintenance is undertaken as and when necessary.

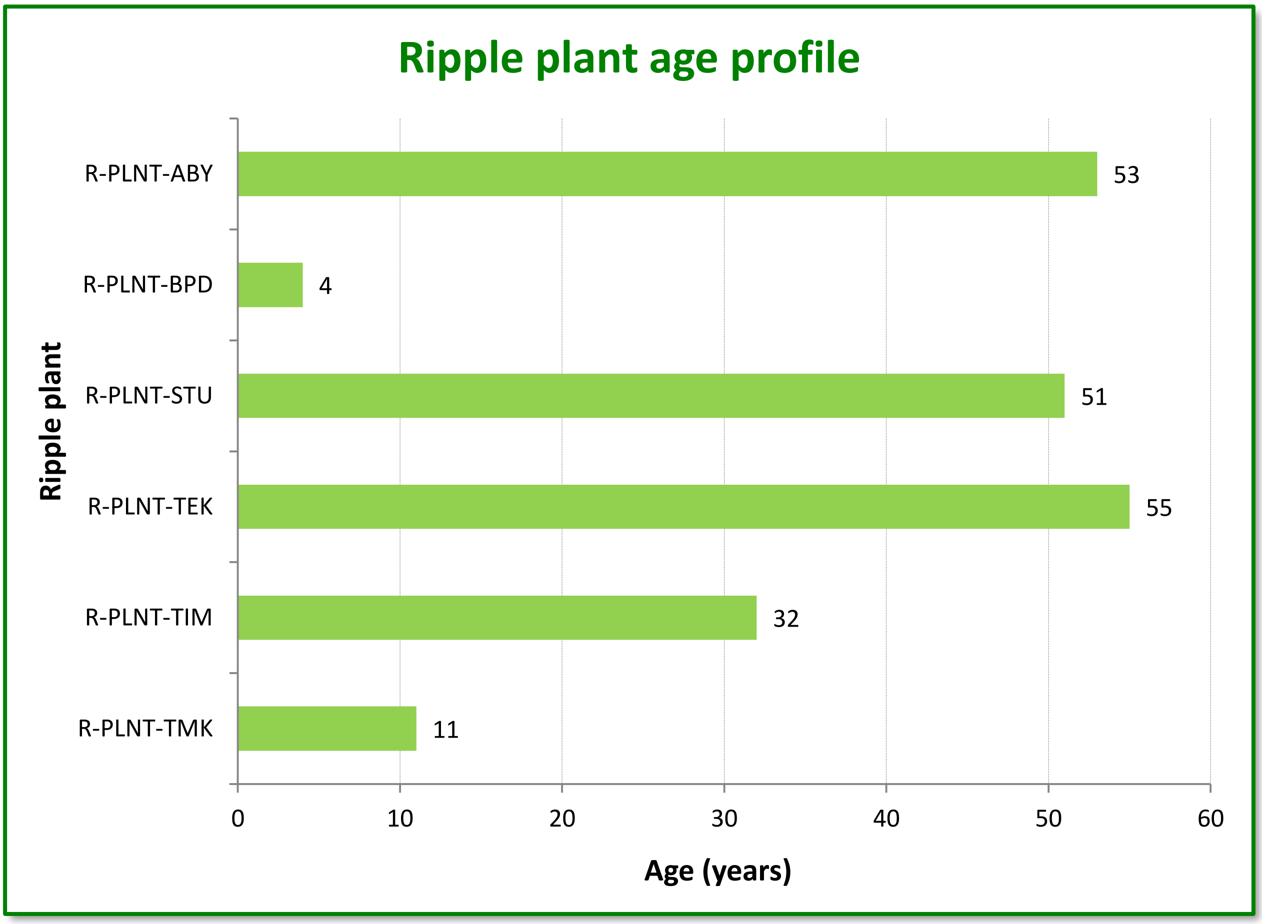
Chapter 6 deals in detail with the life cycle of the network assets, including asset condition assessment, replacement, and maintenance.

3.3.5.2 Ripple plant

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

Photograph 3.4 STU ripple plant

Figure 3.7 Ripple plant age profile



A 10 year program to replace or decommission the old rotating ripple injection plants commenced in 2000. This programme was delayed in 2008 while a short wave radio load control system was considered. Smart meters may provide suitable load control in the future but this is not considered soon enough to meet our immediate requirements for replacing outdated load control assets.

Therefore, it has been decided to recommence the original plan to replace the old rotary injection plants with modern electronic equipment. The replacement of ripple receive relays will be coordinated with the updated replacement programme as shown in Table 3.7.

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 TKA and ABY.

A shared ripple plant has been established at TWZ with NWL. Its frequency is akin to NWL's as they hold the larger population of ripple receivers. With the TWZ 33 kV bus being run split, and NWL being 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.

Table 3.7 Ripple plant replacement programme

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 (to be 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	2015–16	Build and commission new plant at TEK (approximately 800 relays to change).
11	2015–16	Decommission rotating plant at TEK, subject to Item 10 which replaces with modern electronic plant (date revised).

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

The TMK ripple plant was upgraded in 2013 with an automatic selection on its local service supply.

In 2013, two new padmount transformers were sited outside the ripple building and commissioned from D/O fuses off two local 11 kV feeders. These two new transformers supply a new change-over LV local service switchboard inside the ripple building and the old transformers and RMU were decommissioned and removed from the building.

The Albury study of the ripple plant's local service supply proposes replacing the old oil filled CBs and transformer with a modern switch and transformer.

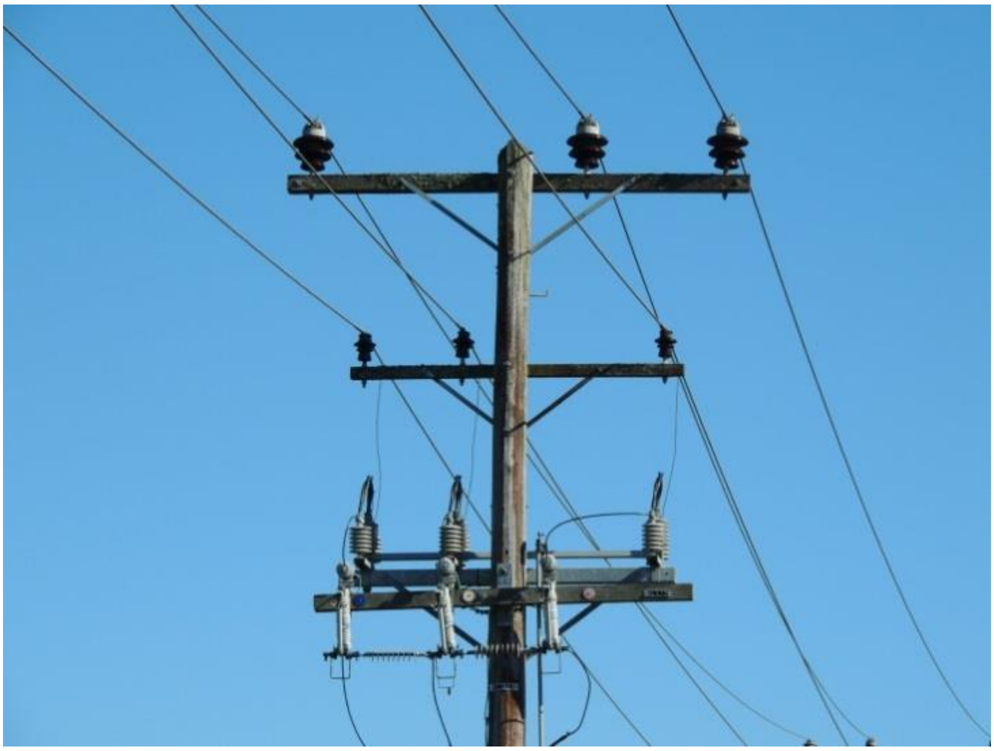
The STU ripple plant has insufficient power output to suit the network due to the growing load. It is suggested by the supplier, after site testing of the asset, to increase the size of the injection cell from 40 kVA to 80 kVA.

With the deployment of smart metering now confirmed, these meters will have the ability to replace the traditional ripple relays. Priority for the deployment of the smart meters is given to the Albury/Fairlie area and the Twizel area. This means that the existing time clocks do not have to be replaced with ripple relays and thus provide a saving in capital expenditure.

3.3.6 Sub-transmission, and distribution lines and cables

The network consists of interconnected overhead circuits and underground cables operating at voltages of 33 kV, 22 kV, 11 kV, 6.6 kV, and 400 V that distribute electricity from zone substations to rural and urban localities. The majority of rural networks are overhead with poles made from soft and hard woods, as well a concrete. Urban networks are a mix of both underground cables and overhead lines.

Photograph 3.5 Running both high voltage (above) and low voltage (below) on a wooden pole



Photograph 3.6 Example of concrete poles used for Fonterra 33 kV line

The percentage of overhead and underground circuit kilometres to total circuit kilometres, regardless of construction type (i.e. three-phase, single phase, and SWER) at each voltage is shown in Table 3.8.

Table 3.8 Percentages of total circuit length for overhead and underground circuits

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

3.3.6.1 Overhead lines

The overhead electrical network has been developed over several decades and it would be difficult to identify a single overhead feeder that had reached its predicted 50 year asset life and still contained all of its original components.

However, there would be original subsections still performing well. This underlines that regular inspection and maintenance occurs to extend the service delivery of overhead systems in a manner that can distort the actual age of an asset segment well beyond the expected life calculated from its initial construction date.

3.3.6.2 33 kV sub-transmission

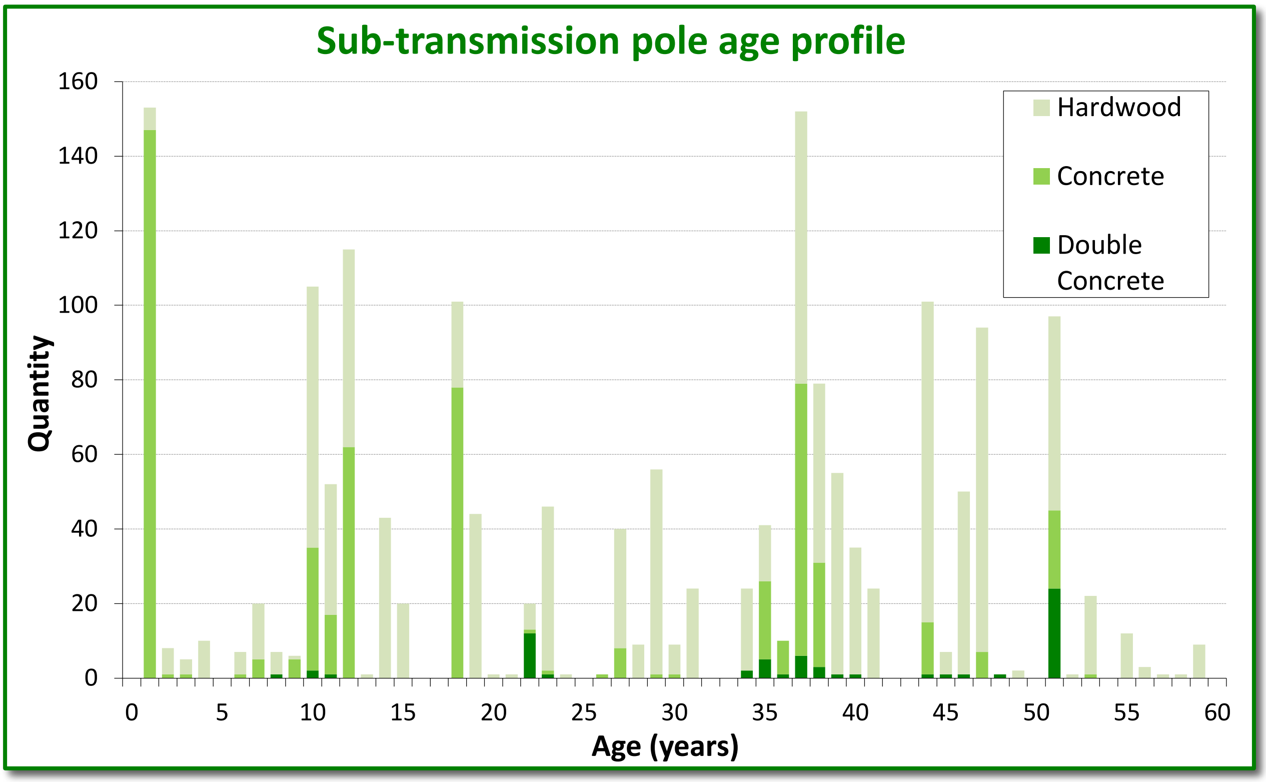
The majority of the 33 kV sub-transmission network was installed during the 1960s and 1980s to meet the growing demand in the rural network. The growth spike that occurred in 1996 resulted from the development of the 30 MVA dairy factory at Clandeboye. In 2004 a new 33 kV line was constructed to supply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

The line to the factory at Clandeboye has experienced vibration since construction and this was measured early in 2012. The results from two recording locations were well below the estimated endurance limit for reverse bending amplitude. Therefore, it is safe to conclude that the existing vibration dampeners are active and effective in containing vibration amplitudes well below the safe vibration limits. No further action is required to reduce aeolian vibration on this line.

Photograph 3.7 Construction of 33 kV lines to Clandeboye Dairy Factory

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

Figure 3.8 Sub-transmission pole age profile



The transmission lines built in the last 10 to12 years will be due for inspection and maintenance in their 20th year of service, unless their condition suggests inspection and maintenance needs be done sooner. Their age and route lengths are shown in Table 3.9.

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

Table 3.9 Sub-transmission lines

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
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

3.3.6.3 11 kV and 22 kV distribution

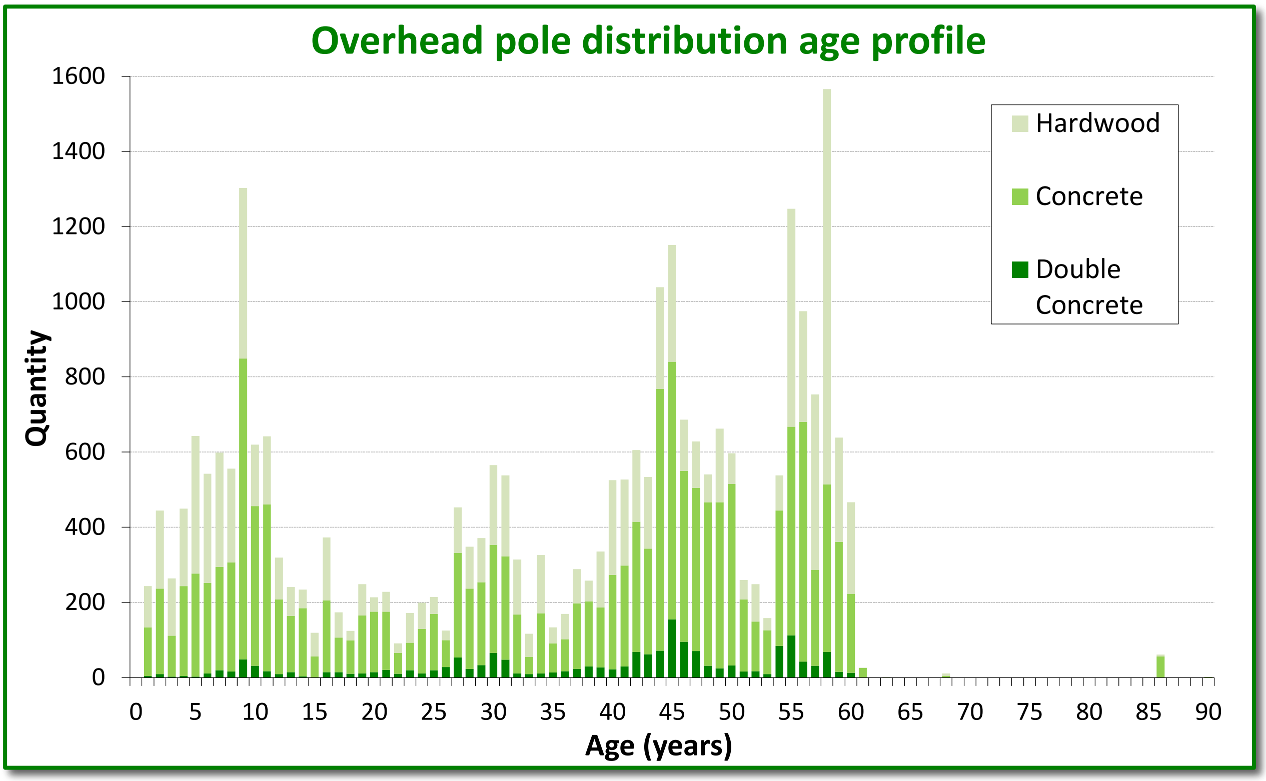
The majority of the 11 kV and 22 kV overhead distribution systems were developed during the 1950s and 1970s. There was little development during the 1980s and early 1990s, with load growth during this period being accommodated within the existing network capacity.

Figure 3.9 shows the age profile of our 11 kV and 22 kV distribution poles.

The majority of the 11 kV and 22 kV overhead distribution systems have been developed over the last 15 years as a result of the significant growth in dairy conversions and irrigation. Most of this increased load has required new line assets to be built. We have done this largely by replacing poles and lines with new poles to support larger conductor or reconstructing existing single phase lines to meet the three phase requirements from irrigation and dairy demand.

Previous AMP age profiles for the distribution (11 kV) network were based on the installation date of the asset. A significant number of the older assets have been refurbished, based on condition assessment, to extend their useful life. Therefore, the effective age of the assets is more correctly reflected in the overhead poles age profile.

Figure 3.9 Overhead pole distribution age profile



3.3.6.4 LV distribution

All new LV reticulation within urban areas must be underground to comply with the various district plans. Rural LV overhead lines are maintained in conjunction with the 11 kV system.

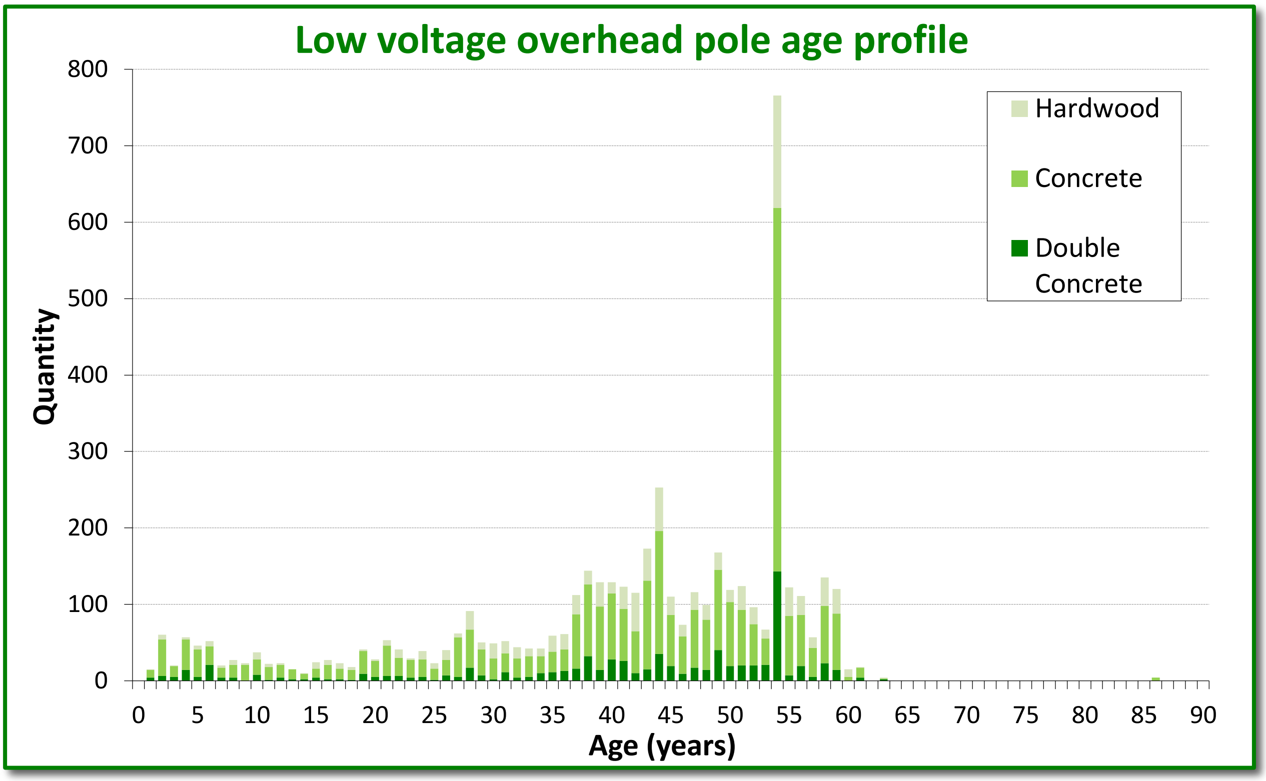
Undergrounding of existing overhead infrastructure will only take place if there is an engineering or health and safety justification for this or if it is requested by the district council.

Where existing infrastructure has to be upgraded, the services will be placed underground.

Existing LV overhead lines will be maintained with like-for-like overhead components. Some capacity problems may occur should domestic demand exceed the smaller and older conductor sizes used. Under existing district council plans, these conductors are unable to be upgraded or replaced overhead and the lines may be required to be placed underground.

Figure 3.10 shows the age profile of LV distribution poles. The majority of poles, including soft/hard wood and concrete poles, are older than 35 years.

Figure 3.10 LV overhead poles age profile



3.3.6.5 Poles and cross arms

The numbers and types of poles are summarised in Table 3.10. These numbers are derived from the GIS field capture project conducted in 2007 and subsequent works updates.

All poles have now been individually identified through this field capture project (2007) and entered into the GIS/AM database (2008–09), with appropriate data relating to age, type, etc. Condition information will be laid over the asset information in successive years to build up a complete electronic asset record. In January 2014 the future use of softwood poles was reviewed. The review concluded that, based on an internal report[8], softwood poles will no longer be used in the network. Following from this, the estimated life for softwood poles has been reduced as shown in Table 3.10.

[8] Softwood Pole Review – Senior Project Engineer – 08/01/14.

The quantities of concrete, hardwood, and softwood poles in the network are shown in Table 3.10 below[9].

Table 3.10 Numbers and types of poles, and estimated life span

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

As many lines were installed during the 1950s and 1960s, this estimate may need to be increased later in the planning period. However, this action would be based on condition assessment, as many of these poles have been replaced during line upgrades to support the dairy industry load growth in the last 15 years.

There are approximately 90% more crossarms than there are poles in the network, allowing for combined HV/LV lines and double arms etc. As each crossarm has a life of 30 to 40 years, approximately 3% of crossarms should be replaced annually. Fortunately, cross arms remain in fair condition and therefore are only replaced when a condition assessment determines they are no longer capable of supporting day-to-day loads.

3.3.6.6 Insulators

Porcelain insulators used on overhead lines appear to have lives in excess of 60 years and have generally given good service. The most recent failures have occurred in recycled pin insulators, and have resulted from over-tightening. Recycled insulators are therefore no longer used. In the last 15 years it has become apparent that there is a problem with certain grey porcelain used in various switch apparatus and two piece insulators, manufactured between 1980 and 1985. The cement used to secure metal or cast components into the insulator (or porcelain to porcelain connections) slowly expands, cracking the porcelain and resulting in some insulators falling apart.

All new 33 kV lines will be insulated with a superior post type insulator instead of the pin type previously used.

Sites where the defective insulators have been used in air break switches (i.e. a disconnector) and blade or fuse disconnect equipment are being identified and prioritised for replacement or refurbishment. It is expected that all such units will be replaced either during maintenance or as required.

[9] Please note that these numbers do not include stub or service poles.

All grey and brown 11 kV porcelain strain disc insulators are now replaced with new glass discs during planned maintenance outages. All new disc insulation is glass.

Other such suspect porcelain components will be identified and replaced as required.

Composite type insulation is permitted in the network only if there is no porcelain or glass alternative.

3.3.6.7 Conductors

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

There are a number of older copper conductor lines in the network. While copper conductor has given generally 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.

Table 3.11 Overhead circuit lengths

Construction type	33 kV	22 kV	11 kV	6kV	400V
Three phase	241.0	28.3	1900.3	0.0	227.2
Single phase	0.0	115.9	851.7	0.0	62.4
Single wire earth return	0.0	0.0	0.0	0.0	0.0

Conductor lifespan has been estimated between 60 and 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 these are not considered at risk of failure.

Assessment will set a replacement priority for smaller copper conductors that have degraded in areas where the consequences of 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 have been identified over the last few years and have been predominantly replaced with ACSR. There may be, however, some isolated 11 kV lines on private land that will be replaced as and when these areas are 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 of these lines have been subject to aeolian vibration during their installed life. Periodic mechanical overloading conditions, from wind and snow, on many of the smooth body conductors will require further assessment of remaining service life.

In areas where ungreased conductors have been installed in coastal environments, between STU and Glenavy, some are now showing signs of corrosion. Due to capacity demands, large amounts of the rural overhead network have been rebuilt in recent years, resulting in many of the older inherently weak and corrosive conductors being replaced. It will be important to continue an acceptable rate of conductor replacement to meet the replacement target over the coming years.

Consultants have been commissioned to analyse samples of both Copper and ACSR conductors to assess their remaining life and recommend strategies for future conductor asset management. Further work is required to progress this objective. 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.

High strength conductors, such as Magpie, Wolf Core, Cub, Snipe, etc., are monitored where they have been installed on large spans 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) have recently been introduced to the network and have performed well to date.

Modern design standards are more conservative than previous designs and should result in a more resilient network.

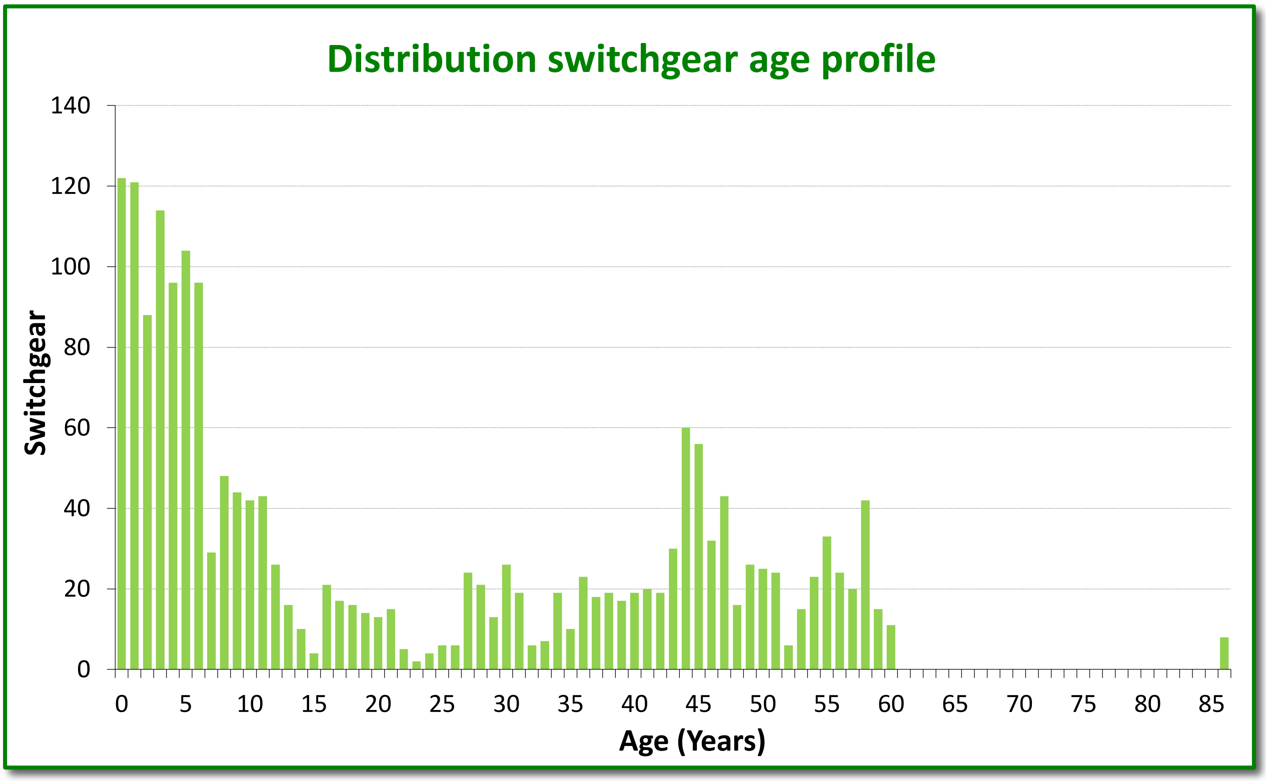
3.3.6.8 Pole mounted switchgear

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

The distribution network supports a range of switchgear from 11 kV drop out fuses, disconnectors (air-break switches) and 11 kV links through to 11 kV reclosers and sectionalisers. Transformer fuses are now excluded from the age profile in Figure 3.12 at page 60.

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

Figure 3.11 Distribution switchgear age profile



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

Photograph 3.8 Pole mounted air break switches

To avoid ferro resonance for 11 kV cable lengths over 50 m and/or transformers >1 MVA, the cable termination is protected with a disconnector (3-phase disconnect), surge arresters, and a 3-phase gang drop-out fuse unit.

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.

Reclosers and sectionalisers are being upgraded as older style oil weight and chain devices are being replaced with modern vacuum electronic equivalents. More reclosers are being purchased and installed 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 had significant reconductoring and repoling projects, as have the feeder sections from the STU substation, to support load growth in Otaio, Waimate, Morven, Waihaorunga, and Springbank. Ikawai and Glenavy areas are fed by BPD.

Voltage regulators have been added to maximise the capacity of the larger conductors that are close to the substations. These regulators provide voltage support for the lighter conductors further out from the areas that have been reinforced. This provides greater economic benefit than full reconductoring of the feeder.

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

Photograph 3.9 AVRs at Pleasant Point

3.3.6.10 Pole mounted transformers

Due to seismic constraints, the Network Standard requires any new transformer 300 kVA or larger to be ground mounted. During the next 20 years, the existing pole overhead transformer structures in urban areas not meeting this 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. These supply power at 400 V, 11 kV, and to a lesser extent 33 kV. A large number of consumers are supplied by these cables, so it is necessary to have some indication of when cabling will need to be replaced and how much this will cost. Type and quantity of cable is shown in Table 3.12.

Table 3.12 Underground circuit lengths

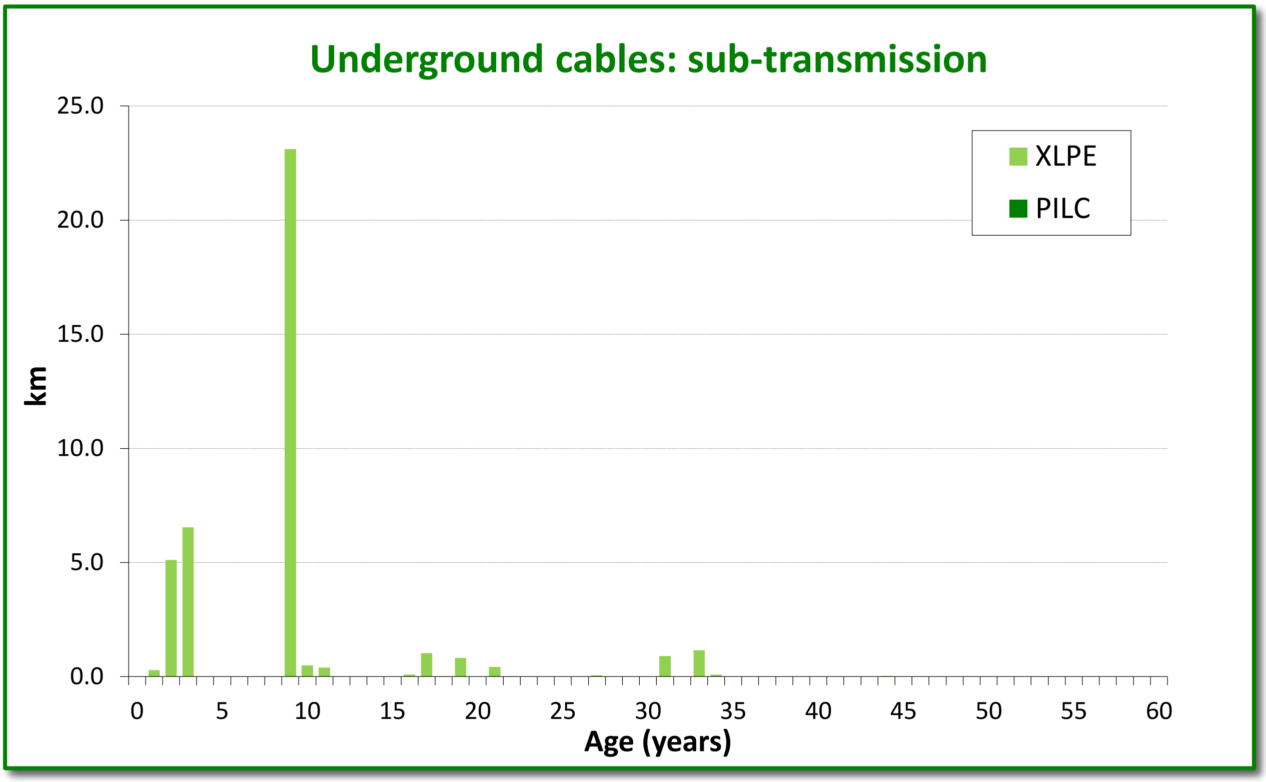
Construction type	33 kV (km)	22 kV (km)	11 kV (km)	6.6 kV (km)	400 V (km)
Three phase	28.8	0.9	291.9	0.0	315.0
Single phase	0.0	0.5	43.6	0.0	7.5
Single wire earth return	0.0	0.0	0.0	7.2	0.0

The age of underground 33 kV sub-transmission cable is shown in Figure 3.12.

Clandeboye was reinforced with two 33 kV cables during 2004 to meet Fonterra's security and supply requirements. Cabling was favoured as there was not an easy route for a double circuit overhead line without significant easement negotiation.

Partial discharge mapping was performed on the Clandeboye cables as part of Alpine's preventative maintenance programme. All 33 kV cables on our network are less than 35 years old.

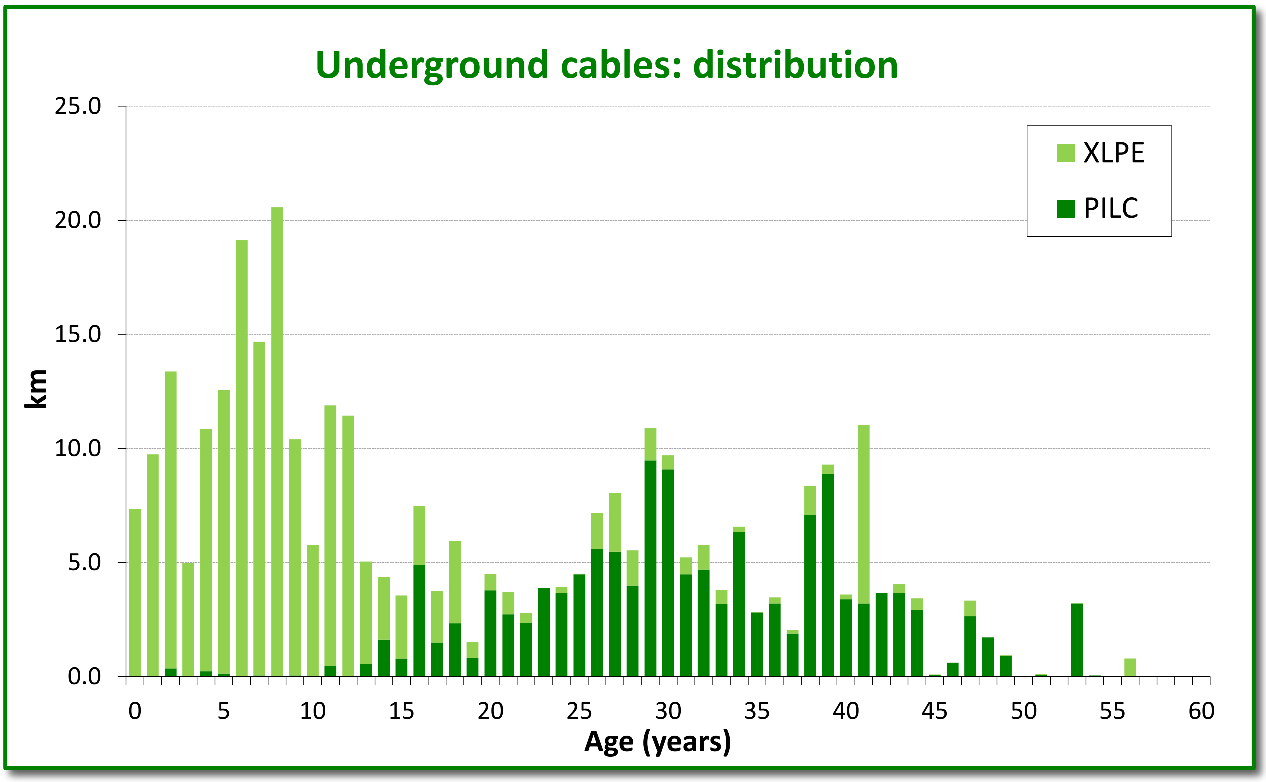
Figure 3.12 33 kV Sub-transmission cable age profile



Photograph 3.10 Damaged underground cable

The age of distribution cables is shown in Figure 3.13.

Figure 3.13 Distribution cable age profile



Major transmission cables, in previous years, were off line VLF partial discharge tested every five years to monitor their condition. Recent joint failures to the sub-transmission cables have increased the partial discharge frequency to a biannual test as a predictive means of determining change in cable joint condition. Our cable faults tend to be due to joint failure, unfavourable installation conditions, or foreign body or mechanical interference. Accordingly, we have not found a quantitative analysis method that helps to accurately predict the occurrence of cable faults.

In the absence of reliable data on the longevity of cables of either type under the conditions experienced in our network, we have assumed the lifespan of our cables to be the same as those specified by the Commerce Commission in its ODV handbook[10].

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. This difference is due to advances in XLPE materials and construction made in 1986 that lead to XLPE cables having a significantly longer service life. It should be noted that these figures are pessimistic

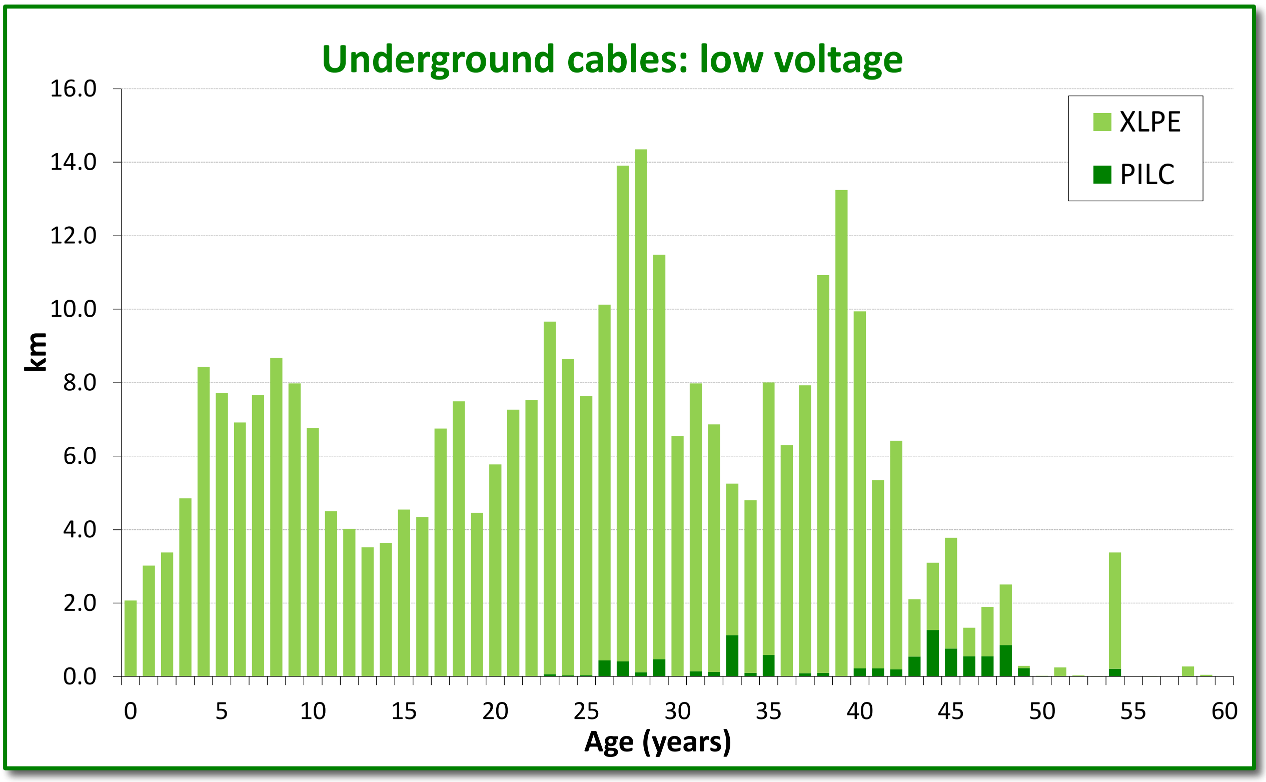
[10] Commerce Commission, *Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Lines Businesses*, 30 August 2004, Table A.1: Distribution ELB Standard Replacement Costs and Lives.

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 will remain advised in the identification of cable condition trends and make informed assessments of any premature failures to determine the effect on the remaining population's future performance.

VLF Partial Discharge testing has been adopted as the preferred HV cable test technique to avoid treeing of the XLPE insulation from HVDC test techniques.

The age of LV cables is shown at Figure 3.14.

Figure 3.14 Low voltage cable age profile



The HV and LV cable 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 within the last 25 years. The majority of the oldest cables are of PILC construction, which has a 70 year life, while the more recently installed cables have been of PVC (20 to 40 age group) and XLPE (generally more recent) construction. These more recent cables have an expected service life of 45 years.

Photograph 3.11 North Street underground cables

A system has been implemented to log cable faults to build up a history of statistical data in order to monitor performance of cables and record failure modes.

There has been, until recently, only one or two 11 kV joint failures per year which is statistically low compared to the total number of joints.

A similarly high incidence of contractor-induced cable faults was experienced in 2012 due to the large number of contractors working in the Timaru area on the ultra-fast broadband (UFB) project. 2013 has seen a smaller incidence of this type as these contractors become more experienced at locating and avoiding our cables.

However, 2008 experienced a greater number of 11 kV cable and cable joint faults than expected. These were mainly due to contractor damage to cables while working on upgrading other services such as water and sewage for the TDC. The one or two other faults were the result of ‘1987’ vintage plastic 11 kV joints succumbing to partial discharge failure.

Faulted joints from 2008 had been sent to a cable joint supplier for testing. However, the cable joint supplier was not able to provide much insight on the expected remaining service life of the suspect cable joints of the 1980 decade. The emphasis is now on interpreting partial discharge mapping, which provides valuable information on the present (at time of tests) joint condition and allows 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’s CBD is a ‘compromise underground system’. It is generally planned to maintain this system above ground unless the building is being completely demolished. The cost to completely replace it with an underground system is relatively high, at more than

$200 per metre. Maintenance over 2009–10 mainly involved replacement of LV joints and link boxes, both in original site and moved to pavement level. However, the 2010–11 earthquakes in Christchurch may encourage a review of this policy.

The majority of the cables in the underground LV network are less than 35 years old. The replacement is likely to be outside of the period covered by this AMP.

However, during condition assessments of all LV distribution and link boxes in 2009–10, including thermographic inspections, a number of the in-pavement Lucy Box link and fuse boxes in the Timaru CBD had been found to have overheated components. The investigation and analysis of this phenomenon is yet to be completed and the causes (possibly several) have yet to be reported in detail. If the problems relate 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 be within the boxes themselves only, the maintenance solution will be of a relatively lower cost.

A programme has been commenced in 2014-15 to systematically replace, over five years, all the central city Lucy Boxes with above ground distribution/link boxes so as to eliminate the Lucy Box issues and allow easier access to the underground and other distribution subs for maintenance and operation.

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. The age profile of the distribution transformers resembles the 11 kV overhead line and cable age profiles. The most significant investments were made in the late 50s, early 70s, 2000s, and now 2010s.

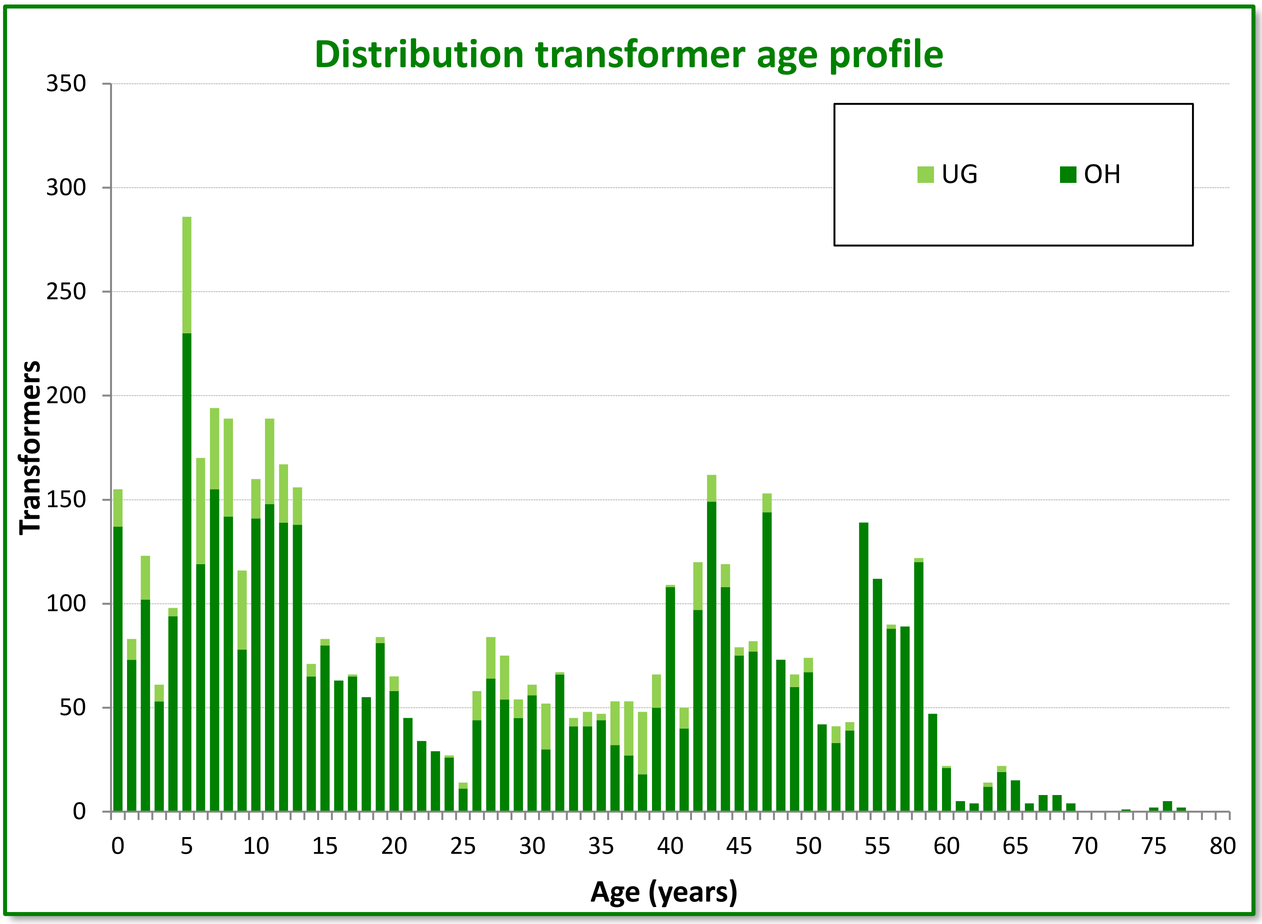
While the majority of our distribution transformers are less than 30 years old, some date back more than 70 years. The age profiles of our distribution transformers can be seen in Figure 3.15.

The expected lifespan of a typical distribution transformer is 50 years. However there is a large variation in the true life of a transformer due to ambient conditions and how hard they are operated over their lifetime.

The history of other networks has shown us that lightly loaded distribution transformers in cold conditions can be expected to last 80 years. This is very applicable as Timaru's average ambient temperature is 12^{o}C compared with the design standard of 20^{o}C.

Irrigation installations use the transformer capacity for approximately less than half of the year. 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 visual signs of age (e.g. rust) it is replaced and, if appropriate, mechanically and electrically refurbished. If the transformer can be serviced economically, it is returned to service with the next line maintenance; otherwise, it is scrapped. The frequency of this rolling maintenance program ensures that individual transformer condition is never poor and will not compromise network reliability.

At present there are only 853 transformers older than 50 years. However, if no transformers are removed, this will increase to 1,841 in the next 10 years. This large increase in the older transformer population warrants targeting this population for specific inspection, rather than through 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 of the transformers on the network at present have at least 10 years of remaining life because of the current refurbishment program. With targeted assessment of the highest aged population segment, the remaining life of these transformers will be determined during the next 10 years.

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

Table 3.13 Distribution transformer quantities by substation type and kVA rating

Type	< 20 kVA	< 50 kVA	< 100 kVA	< 200 kVA	< 300 kVA	< 500 kVA	< 750 kVA	< 1000 kVA	>= 1000 kVA	Total
Concrete pad mounted	1	70	25	63	144	86	41	7	8	**445**
Ground mounted (double end)	0	0	2	7	54	32	15	0	1	**111**
Ground mounted (single end)	2	1	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	14	13	1	2	**30**
Mounted indoors	0	0	1	1	4	13	7	6	14	**46**
Pole mounted	2,637	916	645	374	150	27	1	0	2	**4,752**
Pole mounted (1.5 pole)	0	0	0	0	1	0	1	0	0	**2**
Pole mounted (2 pole)	2	1	1	6	15	9	2	0	0	**36**
Substation (ground mounted)	1	2	3	5	8	2	10	1	4	**36**
Total	**2,643**	**990**	**677**	**456**	**380**	**214**	**111**	**18**	**33**	**5,522**

3.3.7.1 Ground mounted distribution substations

There is a variety of methods employed to safely enclose transformers which are ground mounted. The majority are commercially manufactured integral with the transformer and provide enclosures for LV and HV connections and fittings. The typical ground mounted transformers on our network are categorized as follows.

- Underground—below ground bunker (Timaru MED area only).
- Cubicle —large steel 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 oldest underground substation in Timaru currently in service was built in 1960.

A newer generation of Timaru underground substations date from a 1970 design that replaced older designs which are mostly no longer in service as substations.

The underground substations of the 1970 design 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 changing of transformers or switchgear. Removing roof slabs is rare and would normally be avoided unless absolutely necessary. Fortunately, these substations are relatively reliable with only a few incidents in the design's 40 year life.

They 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 underground substation has continuous fan-forced air ventilation for transformer cooling and operator fresh air.

They also contain a sump pump as some of these substations can be prone to flooding under heavy, extended rain conditions. They are all checked and maintained as necessary after heavy rain.

Most of these substations are entered by a pavement manhole and vertical ladder.

There are some 30 underground distribution substations on the inner city network, which should be refurbished before they reach the end of their economic life. If any earlier opportunity arises then the underground substations will be rebuilt at ground level. The availability or cost of land for these substations has been identified as a possible risk to the replacement process. Risk analysis is used for these individual cases.

For those central city underground substations which need renewal or refurbishment, but where land is not available to re-site them 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 from 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 spaces procedures before operating the equipment.

However, the cost of this option proved to be prohibitive, even when allowing the project to be spread over 20 years.

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

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

This 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 (LV and RMU units). This may include for either location above ground or upgrading with a remote operable unit. The equipment requiring less regular access and attention (transformers) would be renewed last in the overall renewal programme.

The condition of these substations is generally good but safety issues relating to accessing enclosed spaces for operating switches will result in them being refurbished, as indicated above, before the end of their economic life.

Once the proposed refurbishment design is completed, the project will study the priorities for refurbishing these underground substations over the next 20 to 30 years, in line with operational and safety considerations, as well as age and condition assessments.

This work would be done under a planned Capex asset renewal category budget.

3.3.7.3 Surface mounted subs

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

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

Most surface mounted substations would include an LV panel in the LV cabinet consisting generally 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 subs have Lucy type porcelain HRC fuse link holders fitted, with the newer kiosks, padmounts, and building subs (since the 1980s) 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 links or MCCB LV panels, these would be replaced with the modern plastic type shrouded HRC fuse link ways or modern MCCBs, as appropriate. Another exception to HRC fuse links is the use of Statter LV oil switches in underground subs, some kiosks, and on two pole subs. The renewal solutions for the Statters are: for two pole subs—either HRC fuse switch or ganged fuse holders; for underground and surface subs—plastic type HRC shrouded fuse link ways.

Photograph 3.12 Clandeboye distribution substation for Dryer 3

The main maintenance issues with surface mounted distribution subs are graffiti, rust, deteriorating paint work, accumulation of dust, leaves and other environmentally related material, weed control, and, most importantly, checks of the condition of the electrical assets and for oil leaks (rare) from the transformer and/or HV switchgear.

3.3.8 Line regulators, capacitors, and rural switches

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

This equipment includes:

- voltage regulators—to correct from 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
- load 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 (lightning) arresters.

Photograph 3.13 Disconnectors—air break switches (ABS)

3.3.8.1 Voltage regulators

Voltage regulators are automatic devices that monitor the voltage on 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.

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 where the higher line impedance of a lighter distribution line would otherwise result in unacceptably large voltage variations as the line current varies with fluctuating total instantaneous consumer load.

11 kV voltage regulators are a relatively economic solution for compensating for varying load induced voltage fluctuations compared to the cost of reconductoring. They 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 conductor upgrading.

The size of the regulators currently being used for general line regulation is 200 A. There are a few older units rated less than 200 A but newer units met the current 200 A standard for the network. One set of 300 A regulators has been installed in a heavy feeder.

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 feeders or zone substations can be realised.

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

3.3.8.2 Capacitors

11 kV capacitors are another means of compensating for voltage drop on an 11 k V line. In this case 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 the base voltage drop; it may also be used in association with one or more regulators.

3.3.8.3 Reclosers

We use pole mounted reclosers (referred to as 'reclosers') in rural areas for feeder circuit breakers in small rural zone substations. They are also used as overhead line circuit breakers for automatic fault clearance and reclosing (in case of an intermittent fault, such as bird strike or momentary tree branch contact).

Photograph 3.14 Line recloser

Reclosers are sometimes used for line protection duty permitting fault clearance of outlying faults via operation of fuses. As well, reclosers break up a long feeder into smaller sections, avoiding tripping of the zone substation circuit breakers (which supply large urban and rural loads) for remote faults. This helps to avoid both unnecessary momentary interruptions to supply 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 disconnectors)

These are generally SF_6 or vacuum insulated switches that are rated to break load but not fault current. These are capable of operation via a radio network to allow 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 and they are configured for manual operation at this time.

3.3.8.5 Load-break disconnectors (air break switches fitted with interrupters)

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

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 in a reliable condition. Since 2008, we have standardised an interrupter model which is much less prone to going out of adjustment.

3.3.8.6 Disconnectors (air break switches)

We have a large number of installed disconnectors of various models and ages. These are standard items that are required in steady quantities to allow off-load sectioning of the overhead 11 kV network and three phase breaking of connected but unloaded or very lightly loaded lines.

3.3.8.7 HV fuse links

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

The older glass type fuse links are being superseded by the more modern, reliable, and versatile drop out type.

The standard type of fuse link only allows single phase break. This means that they sometimes require to be installed in series with a disconnector when a three phase break is required. Examples include a short cable spur to a transformer or where there is a motor that must not be single phased.

Photograph 3.15 HV fuse link for spur line

3.3.8.8 Surge (or lightning) arresters

These are often associated with particular items of assets such as transformers, regulators, HV cables, etc. as well as for general line surge protection.

Surge arresters are designed to passively detect and limit over-voltage surges due 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 over-voltage. This allows current to flow to earth, dampening the steep leading edge of the surge wave (which generally travels along the line at nearly the speed of light).

This 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 avoiding a short circuit condition 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 action to attempt to protect the arrester from damage. This prevents a short circuit developing that might trip the upstream protection. These arresters then 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 includes voltages at or below 400 V p-p, 230 V p-n.

LV overhead construction was the traditional method of reticulating urban areas, as well as rural areas, in the early days of the New Zealand electricity industry. LV overhead distribution lines exist predominantly in urban areas.

However, for many years now, new LV reticulation has been required by the district council plans to be placed underground, both in the country and in the town.

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

We still have a significant amount of existing overhead LV reticulation, both in the town and country areas. Following the resulting damage to underground cables from the Canterbury earthquakes, the decision was made to cease our overhead to underground programme and to instead convert to underground on an application basis. Accordingly, our AMP no longer includes forecast expenditure for overhead to underground conversions as was reported in prior AMPs.

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 present standard for LV reticulation includes for the use of three core Al, each core XLPE insulated, neutral screen Cu, with PVC sheath, complying to AS/NZS 4026.

3.3.9.2 Distribution boxes (boundary boxes)

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

We have a number of different types of distribution box in service as styles, materials, and technology have changed over the years. These 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.

Photograph 3.16 Link box

Similarly to the distribution boxes, there are several models of link box (of different constructions and materials) in service.

3.3.10 Protection relays, SCADA, and communications systems

Protection relays protect the network from electrical faults by detecting over-currents or over-voltages, or other out of limit conditions. They then trip circuit breakers to clear the fault or abnormal condition from the network. This is necessary to protect assets such 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 the associated UHF microwave communications system.

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, transformer tap positions, etc.; and 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.

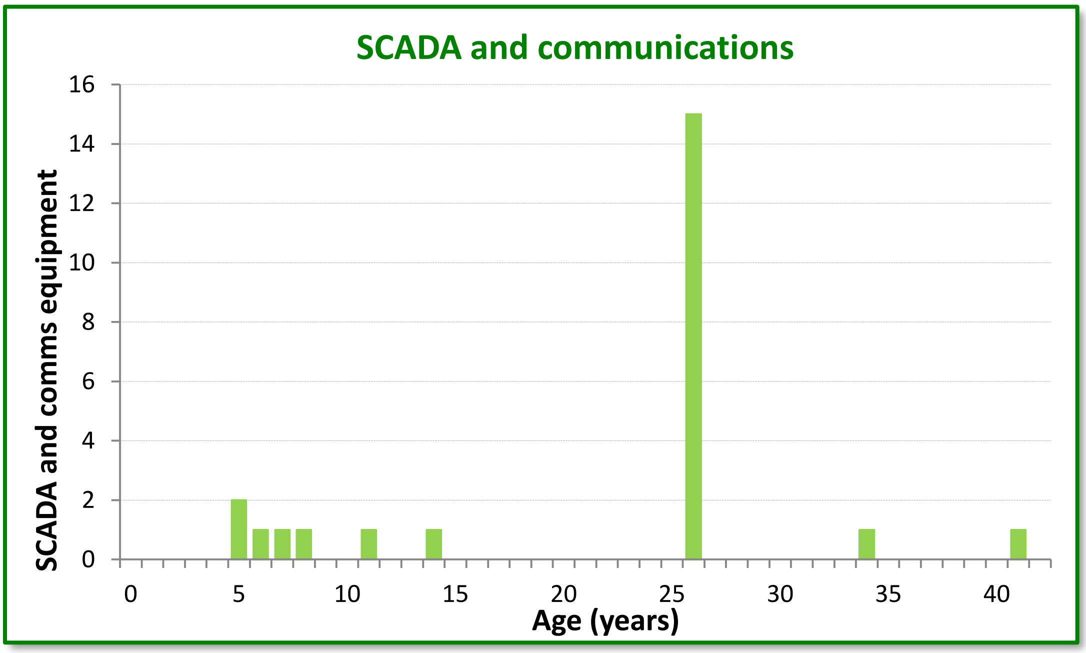
3.3.10.2 Voice radio

Our voice communication system consists of FM, E band, VHF, mobile, portable and fixed site radios operating through hill top 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 VHF signalling, to enable local repeater area operation if desired.

This voice radio arrangement is also used to return alarm signals from some zone substations. These use tone encoding signals that feed through to the SCADA master. Controls 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 age of the assets which are now requiring more servicing to maintain transmit levels within the correct power regions.

Figure 3.16 SCADA and communications age profile



Implementation is over a five year period to retain a level of service coverage to renew and extend the functionality of our radio communication system.

Cell phones are used to complement and backup radiotelephones in many situations. All communications for system operation and control are through voice radio.

3.3.10.3 SCADA communications - radio system

The company has a legacy SCADA communications system that presently comprises 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 to complement, then upgrade, then replace the legacy system. This new system is discussed further near the end of this section.

The legacy SCADA communications system paths are:

- Washdyke—Mt Misery—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 is planned to be replaced in 2014 with a more modern Survalent Master Station.

The Master Station allows for DNP3 communication to field RTUs and IEDs.

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

The new communications utilises a 5 GHz digital radio network backbone, 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.

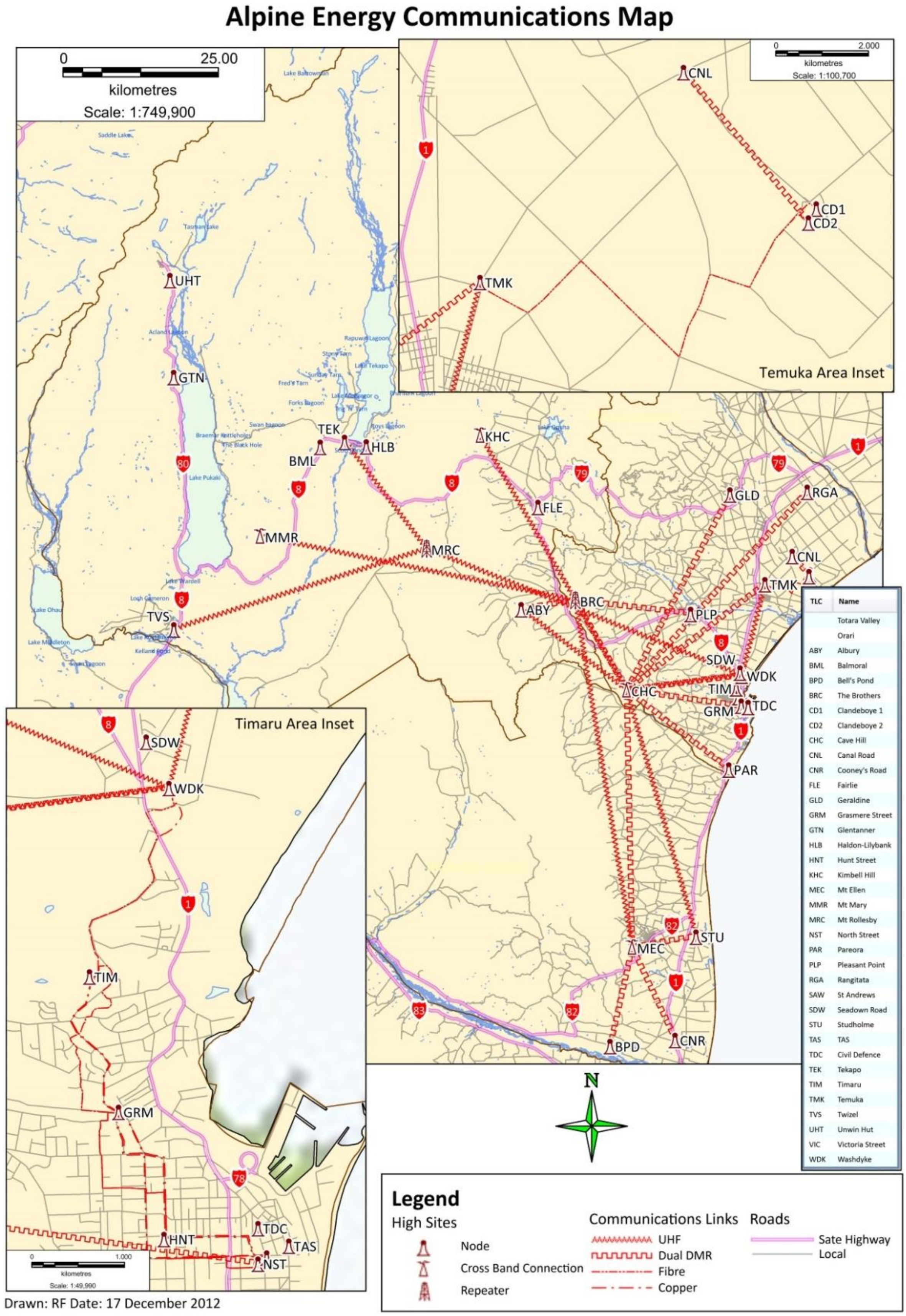
Only STU, TIM Ripple, TVS, and TEK zone substations are still using the legacy UHF/Conitel network. These substations will be upgraded into the 5 GHz network in future years.

An interim upgrade step for TVS and TEK zone subs may include replacing the aging legacy Contitel RTUs with permanent, new RTUs incorporating DNP3/IP comms. The comms would then be temporarily passed over a leased TCP/IP link from each substation to Washdyke Control Room. A FLE sub comms upgrade from the simple legacy VHF tone call alarm to a full SCADA DNP3 RTU could be catered for in a similar manner.

Then, when the 5 GHz comms is eventually established for these and other western substations, the temporary leased comms links would be phased out in favour of the new 5 GHz system.

Photograph 3.17 SCADA—remote terminal unit, Timaru

Figure 3.17 Data communications 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 operation of ripple injection plants located at TIM, STU, TMK, ABY, BPD, and TEK. Details of the plants are contained in the Major Network Asset Management Plan.

The aging legacy Conitel RTU that controls the plant at TEK sub is in urgent need of replacement. See the comment at the end of section 3.3.10.3—SCADA communications - radio system, above, concerning a temporary comms upgrade for the TVS and TEK subs.

3.3.10.5 Protection schemes

We have a number of different types of protection relays and associated assets on our network. These include:

- electromechanical relays
- electronic relays
- numerical relays
- integrated 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
- instrument transformers (e.g. CTs, NCT, VTs, etc.)
- protection relays
- wiring looms
- 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 sub-transmission, GXP, and zone substation arrangements with quite 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 TP GXP supply cables).

As part of our present Capex programme of network upgrades, older protection relays and associated legacy assets are being replaced with modern numeric relays and new associated assets as each substation is refurbished. We have plans to replace all the electromechanical and static relays in the substations not scheduled for major upgrades with numeric relays within the 10 year planning period. This 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 to use us as their MEP or seek metering services from another MEP.

We intend to include as part of our revised standard use of system agreement a provision that our meters are not displaced where a retailer does not choose us as their MEP. We view the information collected from our meters as integral to the operation of our network.

We shall still require the substation ripple injection plants to send the load control signals to the new smart meters.

A programme of recertification of meters was initiated in 2010.

3.3.11 Distributed generation

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

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

Table 3.14 below, summarises the positive and negative aspects of distributed generation.

Table 3.14 Positive and negative effects of distributed generation on the 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.

3.3.11.1 Connection terms and conditions for distributed generation

Procedures for consumers have been developed which provide a simple series of steps they can follow to have small scale (< 10 kW) and larger scale distributed generation connected to the network.

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

Distributed generation that requires a new connection to the network will be charged a standard connection fee, and may also be charged a fee to reflect reinforcement of the network back to the next transformation point.

An annual administration fee may be payable by the connecting party to ourselves.

Installation of suitable metering (refer to technical standards below) shall be at the expense of the distributed generator and its associated energy retailer.

We are happy to recognise and share the benefits of distributed generation that arise from reducing costs (such as transmission costs, or deferred investment in the network), provided the distributed generation is of sufficient size and provides consistent peak demand reduction based on transmission pricing methodologies that provide real benefits.

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

3.3.11.2 Safety standards for distributed generation

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 for distributed generation

Metering capable of recording both imported and exported energy must be installed. If the owner of the distributed generation wishes to share in any benefits accruing to 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 distributed generation will not interfere with operational aspects of the network, particularly such aspects as protection and control.

All connection assets must be designed and constructed to technical standards not dissimilar to 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 Ltd.'s irrigation scheme. The generator operates on the requirements for environmental plus irrigation flow and has a duty factor of 20% so is not available regularly for improvement in supply security. However, it can be used, subject to owners' consent, for islanding to maintain local supply during Transpower outages for one or two days per year. The generator is unable to black start, hence is not deemed a secure supply during islanding operations.

3.3.11.5 Photovoltaic generation on the network

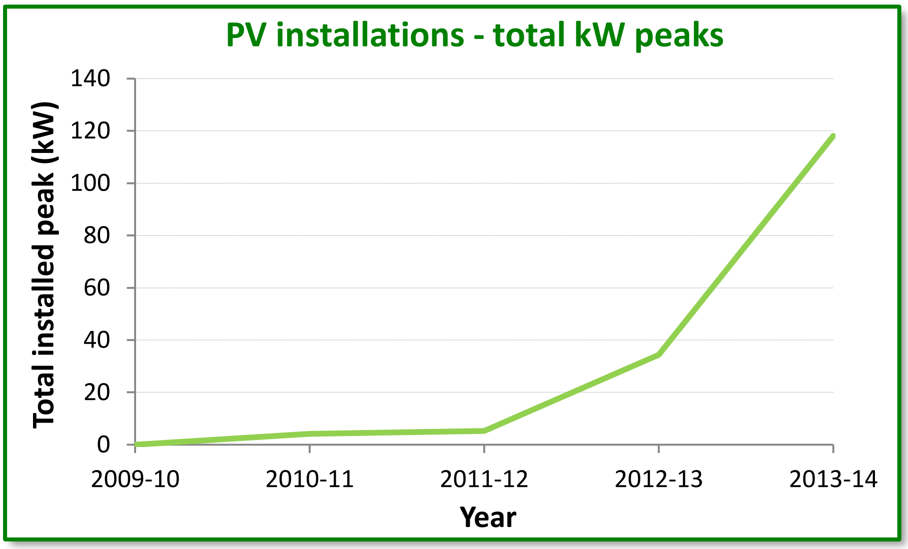
There is growing interest by consumers to install PV systems with inverters that permit export of surplus energy to energy traders back through the electricity network. The rate of connection of such installations has been approximately exponential since 2009. This is illustrated in the following Table 3.15 and Figure 3.18.

Table 3.15 PV installations – total annual installs and kW(peak) per year

Financial year	PV installs	Total installed peak (kW)
2009 - 2010	0	0
2010 - 2011	1	4.1
2011 - 2012	2	5.2
2012 - 2013	10	34.4
2013 - 2014	28	118.1

The statistics for the first quarter (April-June) of 2014–15 were 11 installations and 38.7 kW peak.

Figure 3.18 Growth in peak nominal power by photovoltaic devices from 2009-2014



To provide local data on the efficiencies and economics of such systems within our area of operations, we recently installed a PV array and inverter system on the TEK substation building. Our website provides public access to this data.

Photograph 3.18 External solar panels and the in-house display at the Tekapo substation

3.3.12 Outlook for existing asset configuration

The strong growth in South Canterbury had effectively consumed the available capacity headroom at a number of lines and substations. This has necessitated a reinvestment phase to provide additional capacity to 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 justifying assets 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. This ratio is typically in excess of 99%, meaning that very little optimisation is necessary.

In saying this, however, we also recognise that our network has been built up over 88 years by incremental investment decisions. While optimal at the time, they would probably not be optimal if the network was rebuilt in a single instance of time to supply the exact needs of existing consumers.

We create stakeholder service levels by carrying out a number of activities (described in Chapter 4—Performance Measures) on our assets, including the initial step of building assets (lines and substations). Some of these 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 switchboard with bus coupler) than our PLP zone substation supplying a residential township and farming areas north-west of Timaru City via a single overhead line. Hence the required level of investment will generally reflect the magnitude and nature of the demand.

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

- how asset ratings and configurations create service levels such as capacity, security, reliability and voltage stability
- the asymmetric nature of under-investment and over-investment, i.e. over-investing creates service levels before they are needed, but under-investing can lead to service interruptions (which typically costs about 10x to 100x as much as over-investing, as was discovered in Auckland in June 2006)
- the discrete sizes of many classes of components (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; in some cases capacity can be staged through use of modular components
- the fact that our existing network has been built up over 80 years by a series of incremental investment decisions that were probably optimal at the time but, when taken in aggregate at the present moment, due to load growth and changing land practices may now be clearly sub-optimal
- 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 it created were equal to the service level required. In a practical world there are asymmetric risks, discrete component ratings, non-linear behaviour of materials, and uncertain future growth rates. Accordingly, we consider an asset to be justified if its resulting service level is not significantly greater than that required, subject to allowing for demand growth and discrete component ratings.

All assets are necessary to meet the load and maintain the reliability and security of supply expected by consumers, as well as meeting regulatory voltage requirements. A small number of assets have been optimised for ODV purposes (most recently in 2004). However, all of these optimisations have been capacity-related (i.e. 33 kV line operating as 11 kV therefore recorded as an 11 kV line, or a medium conductor optimised to a light conductor, no assets have been identified as being superfluous).

Key new load areas are developing adjacent to river boundaries for irrigation of farmland to meet higher land productivity. Assets supplying these 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 improved supply security. Consumer expectations are also an important consideration as supply for the dairying load is preferential to irrigation load, should the occurrence of fault remove supply availability. Once a centre of load has been established, further demand support is provided by changing supply voltage and installing a new zone substation, typically at a 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 ripple relay receivers and lease these to the retailers operating on our network. Metering assets are not covered in this AMP.

See the MNAMP for further information.

4. Performance Measures

4.1 Introduction

This chapter 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 measures in accordance with the various Acts and regulations under which we operate. Our performance measures can be broken down into the following four high level categories:

- safety
- service standards
- service levels
- financial.

Each measure of performance, how that measure is set, how we have performed, and, where appropriate, targets for future performance are discussed in detail in the following sections.

4.3 Safety

Safety is our first and primary value. We maintain our safety policies to keep the public and our people safe. We engage in 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.

4.3.1.1 Internal audits

We carry out internal audits regularly by requiring that:

- the CEO, Compliance & Training Manager, 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.

4.3.1.2 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/NZS7901:2008 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 2012 and remains current for three years (i.e. September 2015).

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 the 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 below.

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

SAIDI provides the consumer with an indication of how long the electricity supply was interrupted during the year. The measure can be reported as whole of network, or it can be disseminated to a much lower level, such as feeder.

4.4.1.2 System average interruption frequency index

SAIFI measures the number of interruptions that occurred during the year. SAIFI is derived using the formula below.

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

SAIFI provides the consumer with an indication of how many times electricity supply was interrupted during the year**.** The measure can be reported as whole of network, or it can be disseminated to a much lower level, such as feeder.

Considering the measures of SAIDI and SAIFI side-by-side gives consumers an indication of whether interruptions on a 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 below.

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

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 the SAIFI. CAIDI can also be reported as whole of network, or it can be disseminated to a much lower level such as feeder.

4.4.2 Setting of 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 performance for the period 1 April 2004 to 31 March 2009[11]. The targets set from 1 April 2015 are set using the 10 year average performance for the period 1 April 200 to 31 March 2014[12].

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 when compared with historical performance. The Commerce Commission uses measures of performance against targets to signal whether there has been a

[11] Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2010, Decision No. 685, 30 November 2009.
[12] 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.

material deterioration of the network reliability over the period. A worsening performance compared to historical could indicate that there is a material deterioration of the network.

Reliability is relatively easy to 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 to 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 the reliability. Our consumer surveys have historically supported this assumption.

4.4.3 Performance against the targets

Table 4.1 shows our un–normalised performance against target between 1 April 2004 and 31 March 2014, and forecast performance for the current year[13] and the year ending 31 March 2016[14].

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

Year	SAIDI (reported in system minutes)		SAIFI (number of interruptions)		CAIDI (reported in system minutes)
	Performance	Variance[15]	Performance	Variance[16]	Performance
2004/05	68.93	-19.27	0.99	-0.11	69.62
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	225.92	+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	884.65	+720.43	2.22	+0.53	398.49
2014/15	163.175		1.579		97.17

[13] Current year performance (1 April 2013 to 31 March 2014) is not finalised at the time that the AMP is published i.e. 31 March 2014.

[14] Forecast performance for both SAIDI and SAIFI for the 2015/16 is based on Commerce Commission targets.

[15] The SAIDI target from 1 April 2005 was 88.20 systems minutes per annum, and from 1 April 2010 is 164.22 system minutes per annum.

[16] The SAIFI target from 1 April 2005 was 1.10 interruptions per annum, and 1 April 2010 is 1.69 interruptions per annum.

4.4.3.1 Normalisation of reliability performance

In its setting of the performance measures, the Commerce Commission recognises that the reliability data is susceptible to variation resulting from events that can be largely outside of the electricity distribution businesses control, such as force majeure events (e.g. earthquakes). To account for this variability, the Commerce Commission uses the IEEE 2.5 Beta method[17] to normalise the annual performance.

We have had our performance normalised at 3 of the last 10 annual review dates.

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

In 2010 we again experienced severe weather events which saw our normalised performance reduce from 332 system minutes to 146, which exceeded the target SAIDI by 57 SAIDI minutes. Due to the severe storms experienced during 2013 we exceeded our performance measures during the 2013–14 year. However, we expect our reliability to come under performance targets from the 2014–15 year.

In June 2013, heavy rain and snow storms followed by high winds in July and then more wind in September saw lines brought down, predominately by trees falling across them. These severe weather events contributed over 660 SAIDI minutes to our reported total SAIDI of 885 minutes. Our normalised performance was 275 SAIDI minutes, which exceeded the target SAIDI by 110 SAIDI minutes. Photographs of the type of damage that we received during the severe weather events of 2013 can be found at Photograph 4.1.

Photograph 4.1 Storm related damage on our network

[17] The IEEE 2.5 Beta Method 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 exceeds the boundary value, the total SAIDI minutes of this event are replaced by the boundary value.

4.4.3.2 Vegetation management remains an ongoing challenge

Vegetation management has been and remains a challenge and a concern for us based on the number of outages and SAIDI minutes attributable to debris from trees blown into our lines.

We are of the view that the Electricity (Hazards from Trees) Regulations 2003, through which the trimming of trees is managed, is inadequate with respect to the defined 'growth limit zone', as the limit only considers clearances from trees in calm weather conditions. The limit set under the regulations of 1.6 meters 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. To counter this, we are approaching tree owners and offering to cut trees which are within the fall zone of power lines.

4.4.3.3 Performance for planned and unplanned interruptions

To get a fuller understanding of our performance we measure our interruptions caused by planned (meaning the consumer is given at least 24 hours' notice that the interruption is to occur) and unplanned (meaning the consumer if given less than, or no notice that an interruption will occur) interruptions.

Measuring planned and unplanned interruptions gives us an indication of the inconvenience caused to consumers by interruptions on our network. It is assumed that the inconvenience of a planned interruption is less than an unplanned interruption because consumers are better able to prepare for the impact of a planned interruption, as they are made aware of the time, date, and duration of the interruption.

Table 4.2 provides the breakdown of our actual performance against target for planned and unplanned interruptions on our network for the year ending 31 March 2014.

Planned outage activity is driven by a need to maintain the network. To avoid planned outages, the majority of customer connections are undertaken using a combination of live line glove and barrier techniques and level 1 live line sticking work (live line clamps).

Table 4.2 Performance summary – planned and unplanned SAIDI and SAIFI

Measure	Target 2013/14	Actual 2013/14
Planned SAIDI – Class B	52	33.59
Unplanned SAIDI – Class C	112	851.06
Planned SAIFI – Class B	0.30	0.15
Unplanned SAIFI – Class C	1.39	2.07
33 kV faults per 100 km	5.81	0.82
22 kV per 100 km	2.08	5.49
11 kV faults per 100 km	8.39	4.62

During 2013/14 we exceeded the set targets for unplanned outages by some seven times the SAIDI target and one and half times the SAIFI target. For the current year, we have forecast that we will perform well within the targets for both planned and unplanned outages.

4.4.4 Causes of unplanned interruptions

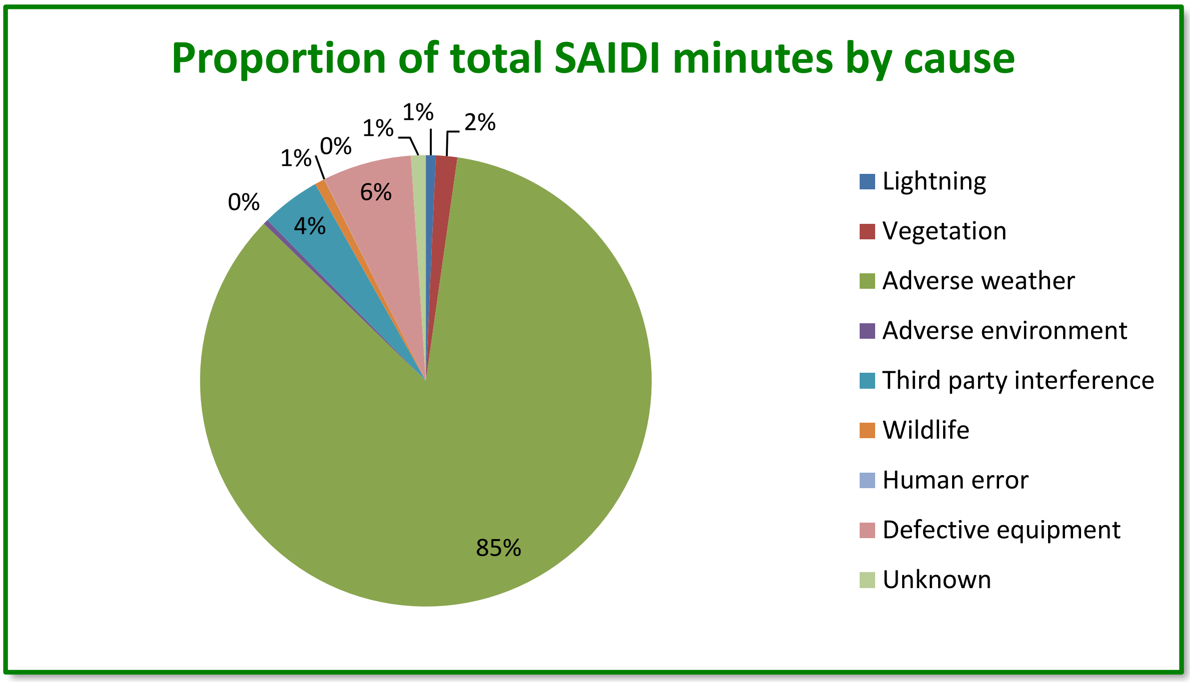
The breakdown contribution of unplanned outages to our overall SAIDI performance is shown in Table 4.3.

Table 4.3 Summary of unplanned outages' contribution to SAIDI minutes

Number of unplanned outages by cause (in SAIDI minutes) during 2013/14			
Cause of fault	**No. of outages**	**Consumers affected**	**SAIDI minutes lost**
Lightning	6	1,342	06:08
Vegetation	19	2,718	13:37
Adverse weather	95	28,896	721:84
Adverse environment	7	1,312	03:28
Third party interference	35	10,097	36:00
Wildlife	6	2,545	06:01
Human error	1	187	00:16
Defective equipment	59	14,884	54:21
Unknown	20	2,151	09:32
Total	**248**	**64,132**	**851:06**

The percentage contribution of all factors affecting the SAIDI minutes lost for unplanned outages for 2013/14 is shown in Figure 4.1.

Figure 4.1 Proportion of total SAIDI by cause of interruption



In 2013/14, the largest cause of interruptions was from natural causes (89%), followed by defective equipment6%. To explain the 6% we look at our worst performing feeders to determine if there is a trend that needs addressing. This is discussed in section 0—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. These improvements will lead to gains in SAIDI minutes. These gains will allow us to have more planned outages which are required for upcoming Capex projects. Overall the impact of improved response times coupled with more Capex related planned outages, will result in a constant level of SAIDI minutes to 2025.

Similarly for SAIFI, the revised targets will allow savings from reduced frequency of fault related outages, to be used for more planned outages required for maintenance, extension, and Capex projects.

Worst performing feeders.

Table 4.4, provides more detail on the causes of adverse weather events. Where the table reads 'no cause found' means that evidence for the cause of an outage was not found. This could be from tree branches which blew away before the cause of the fault was identified.

Table 4.4 Impact of adverse weather on the network

Equipment	Adverse Weather (excluding lightning)	Number of outages	Number of SAIDI minutes lost
33 kV lines	High winds- No cause found	1	27:18
	High winds causing broken binder	1	04:49
	High winds - Trees in line	2	17:56
	Snow Storm	1	31:55
	High winds - Plastic sheeting blown into line	1	05:16
11 kV lines	High winds-Vegetation blown into lines	34	77:46
	High winds-Wires down	1	00:07
	High winds-Broken pole.	1	00:04
	High winds-Lines clashing\twisted	4	00:27
	High winds-Broken binder	2	00:12
	High winds-No cause found	40	519:18
	Snow storm	6	09:52
	High winds - netting blown into line	1	00:02
Total		95.00	721:84

4.4.5 Ten-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 interruptions for SAIDI and SAIFI can be found at Schedule 12d: Report Forecast Interruptions and Duration published on our website.

Table 4.5 Primary consumer service levels

Measure	Year ending 31 March									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
SAIDI	163.2	163.2	163.2	163.2	163.2	163.2	163.2	163.2	163.2	163.2
SAIFI	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58

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. These improvements will lead to gains in SAIDI minutes. These gains will allow us to have more planned outages which are required for upcoming Capex projects. Overall the impact of improved response times coupled with more Capex related planned outages, will result in a constant level of SAIDI minutes to 2025.

Similarly for SAIFI, the revised targets will allow savings from reduced frequency of fault related outages, to be used for more planned outages required for maintenance, extension, and Capex projects.

4.4.6 Worst performing feeders

Reporting worst performing feeders can give distributors an approach for identifying and targeting appropriate expenditure on their network. However, worse performing feeders should not be used as an indicator of reliability as an absolute measure, as distribution networks are dynamic and a change in network configuration will impact on the reported performance of individual feeders.

The ten worst performing feeders as at 31 March 2014 with respect to outages are detailed at Table 4.6.

Table 4.6 The 10 worst performing feeders by outage

Feeder	No. of events	SAIDI (in system minutes)	SAIFI (no. of interruptions)
Fairlie Rural	19	16:37	0.08
Cave	15	31:12	0.06
Morven	14	03:11	0.03
Woodbury	13	65:57	0.07
Speechley	11	50:10	0.06
Winchester	10	44:02	0.12
Totara Valley	10	08:06	0.04
Rolleston	9	26:01	0.06
Raincliff	8	15:13	0.03
Normanby	8	08:42	0.08

The worst performing feeders by number of outages were Levels, Normandy, and Waitohi which had a total of 10 outages each. The worst performing feeder by SAIDI minutes was Normandy with 5.45 SAIDI minutes.

The ten worst performing sub-transmission and feeders as at 31 March 2014 with respect SAIDI minutes lost and causes are detailed at Table 4.7. The worst performing feeder by SAIDI minutes was GLD TS with three interruptions totalling

9.30 SAIDI minutes and 0.13 SAIFI interruptions. Normandy was the worst performing feeder with regards to the number of outages experienced and the sixth worst performing feeder with regards to SAIDI minutes at 5.45.

Table 4.7 The 10 worst performing sub-transmission/feeders by SAIDI minutes

Feeder	No. of outages	SAIDI (in system minutes)	SAIFI (no. of interruptions)
Waimate	7	184:36	0.39
Fairlie (33kV)	5	66:18	0.16
Woodbury	13	65:57	0.07
Speechley	11	50:10	0.06
Winchester	10	44:02	0.12
Otaio	7	38:28	0.04
Cave	15	31:12	0.06
Waitohi	6	29:46	0.02
Geraldine TS	6	29:39	0.13
Rangitata 33kV and 11 kV	2	28:01	0.03

4.4.7 Energy delivered

Our energy delivery efficiency measures are load factor, 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 following 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, if any, peaks and troughs. A low load factor means that only occasionally a high demand is reached. This occasional high demand is referred to as a network peak.

To service that peak we must have capacity available to meet the seasonal, weekly, and daily electricity demand variations. This necessary peak capacity imposes higher costs on the system. Load factor is not a measure of spare capacity in our network rather 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 system at the GXP and the energy supplied at the consumers' connection point. Loss ratio is derived using the following 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 the delivery to consumers' 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, and unread meters.

4.4.7.3 *Capacity utilisation*

Capacity utilisation measures the rate at which potential output levels are being met or used. Capacity utilisation is derived using the following 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 a given point in time without incurring any additional cost. For example, if a network is running at 80% capacity utilization rate, it has room to increase demand by a further 20% without incurring additional costs of building new assets.

4.4.7.4 *Our energy delivery efficiency performance*

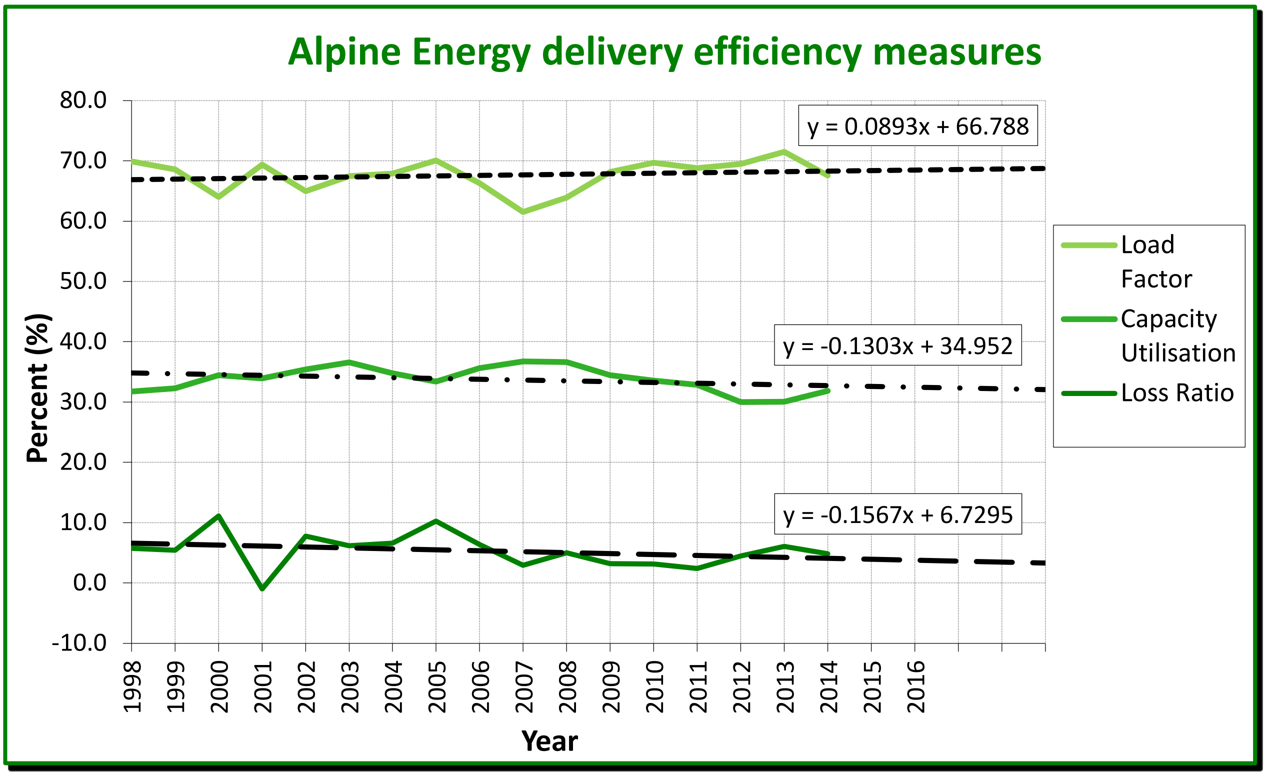
The actual and projected energy delivery efficiencies are listed Table 4.8.

Table 4.8 Projected energy delivery efficiencies

Measure	2014	2015	2016	2017	2018
Load factor	68.2	68.3	68.4	68.5	68.6
Capacity utilisation	32.9	32.7	32.6	32.5	32.3
Loss ratio	4.2	4.1	3.9	3.8	3.6

Figure 4.2 shows how our energy delivery efficiency measures we have tracked between 1998 and 2014.

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 don't 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 operations.

Table 4.9 shows the number of outages consumers might broadly expect in any given year by broad geographical areas.

Table 4.9 Expected service by location

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

4.5.1 How we take account of consumer service level preferences

We conduct consumer surveys every two years to establish consumer preferences for quality and security of supply. Our most recent survey in 2014 of approximately 500 of our mass market consumers resulted in 275 completed responses in regard to perceptions of supply reliability, inconvenience, community disruption, and price. The key conclusions are as follows.

- Most of the surveyed consumers believe that their electricity supply reliability is similar to what it has been over the last few years, with about 13% believing that supply reliability has improved and only 7% believing that supply reliability has deteriorated.
- About 76% of consumers had their electricity supply interrupted for no more than a few hours during the 2013 storms, with a further 9% being interrupted for a whole day. Consumers in the Studholme, Timaru and Temuka market segments appear to have been the worst affected.

- About 65% of surveyed consumers experienced no inconvenience from electricity supply interruptions resulting from the 2013 storms, with a further 27% experiencing some personal inconvenience.
- About 83% of surveyed consumers indicated an unwillingness to pay more to reduce the risk of prolonged supply interruptions due to storms.

The overall conclusion of the survey is that the 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 2014, the most recent disclosures, is shown in Table 4.10.

Table 4.10 Financial performance

Parameter	Target ('$000)	Actual ('$000)	Variance	
			('$000)	As a %
Lines charge revenue	42,160	42,362	202	0.5
Operational expenditure	14,492	15,272	780	5
Capital expenditure	22,607	19,283	-3,324	-15

4.6.1 Lines charge revenue

Target revenue for 2014 was $42.1 million our total billed line charge revenue was $42.4 million. This is a variance of $202k (or 0.5%), which is not considered to be material.

4.6.2 Actual vs forecast expenditure

4.6.2.1 Operating expenditure

Table 4.11 shows the variance between our actual and budgeted operating expenditure for the period ended 31 March 2014.

Table 4.11 Variance in our operating expenditure as at 31 March 2014

Operating expenditure category	Target ('$000)	Actual ('$000)	Variance ('$000)	Variance As a %
Service interruptions and emergencies	1,485	1,979	+494	+33
Vegetation management	123	110	-12	-10
Routine and corrective maintenance and inspection	2,946	3,232	+285	+10
Asset replacement and renewal	798	572	-226	-28
Expenditure on network assets	5,352	5,893	*+541*	*+10*
System operation and network support	4,057	4,978	+921	+23
Business support	5,083	4,401	-682	-13
Expenditure on non-network assets	9,141	9,379	*+238*	*+3*
Total operational expenditure	**14,492**	**15,272**	**+779**	**+5**

We overspent for operating expenditure over the period by 5%. Target operating expenditure was $14.5 million whereas actual expenditure was $15.3 million. This result is largely attributable to the additional expenditure following the extreme weather events of 2013.

4.6.2.2 Capital expenditure

Table 4.12 shows the variance between our actual and budgeted capital expenditure for the period ended 31 March 2014.

Table 4.12 Variance in our capital expenditure as at 31 March 2014

Capital expenditure category	Target ('$000)	Actual ('$000)	Variance ('$000)	Variance As a %
Consumer connection	2,703	3,701	+998	+37
System growth	9,228	8,775	-453	-5
Asset replacement and renewal	3,524	2,688	-836	-24
Asset relocations	0	265	+265	+100
Reliability, safety and environment	5,841	2,585	-3,255	-56
Expenditure on network assets	*21,295*	*18,015*	*-3,281*	*-15*
Expenditure on non-network assets	*1,312*	*1,268*	*-44*	*-3*
Total capital expenditure	**22,607**	**19,283**	**-3,325**	**-15**

Our capital expenditure was under budget for the period by 15%. Target capital expenditure was $22.6 million whereas actual was $19.2 million. The variance is attributable to the following reasons.

In 2013 we experienced severe storm damage. The outcome of this on our Capex reporting was that some asset replacement, and reliability, safety and design Capex was completed as Opex when we repaired our network from the storm damage.

A second reason for the variance in our Capex spending was due to resource consent issues on two reliability and safety projects worth $1.5 M.

Finally, our contractor NETcon was not able to provide resources required for a large Capex spend due to the resources needed for storm damage repair and ongoing earth quake related repair work in Christchurch, the latter continuing to use up spare labour resources.

4.7 Justifying service levels

We justify our service levels based on the following.

- The majority of our consumers have expressed a preference for us to maintain historical levels of continuity and restoration in return for paying about the same price.
- Prioritising work to the network within the constraints of the lines charge revenue that we receive under the price path.
- The physical characteristics and configuration of the network that embody an implicit level of reliability which is costly to significantly alter, but which can be altered if a consumer or group of consumers agrees to pay for the alteration.
- The diminishing returns of each dollar spent on reliability improvements.
- Consumer specific request, and agreement to pay for, a particular service level (e.g. uninterruptable supply).
- When an external body imposes a service level or in some cases an unrelated condition or restriction that manifests as a service level. For example, a requirement to place all new lines underground or a requirement to maintain clearances.

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

5. Network Development Planning

5.1 Introduction

This chapter describes our planning process, forecasted load (including load projections for each GXP and related substations), and planned material Capex projects (over $450,000). Renewal drivers are discussed in chapter 6. We are also enhancing the overall planning process. For more discussion on this, please see section 8.3—Continuous improvements to our asset management system.

5.1.1 Background to our planning

South Canterbury has traditionally been a sheep and crop farming region, with near zero annual population growth[18]. 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.

Recently, South Canterbury has seen major changes to rural land use with many farms converting to dairy (on irrigated pastures) in response to high dairy returns with respect to other forms of land use. Dairy conversions have also been enabled by the Canterbury Regional Council (ECan), and by the presence of two new dairy processing plants which have been built in addition to the expanding Clandeboye site.

Discussions with investors reveal that load growth over the next five to ten years from step changes could increase peak network capacity by more than 40%[19]. In this environment, we are unwilling to begin material Capex projects until a firm commitment from investors is made to us in the form of capital contributions.

[18] Based on Statistics NZ census data, average annual population growth for South Canterbury (from 1996-2013) has been 0.14%. South Canterbury has historically had dairying at low levels.
[19] Discussions with investors have revealed potential future load from additional dryers at Clandeboye, ODL, proposed irrigations 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 at the strategic level

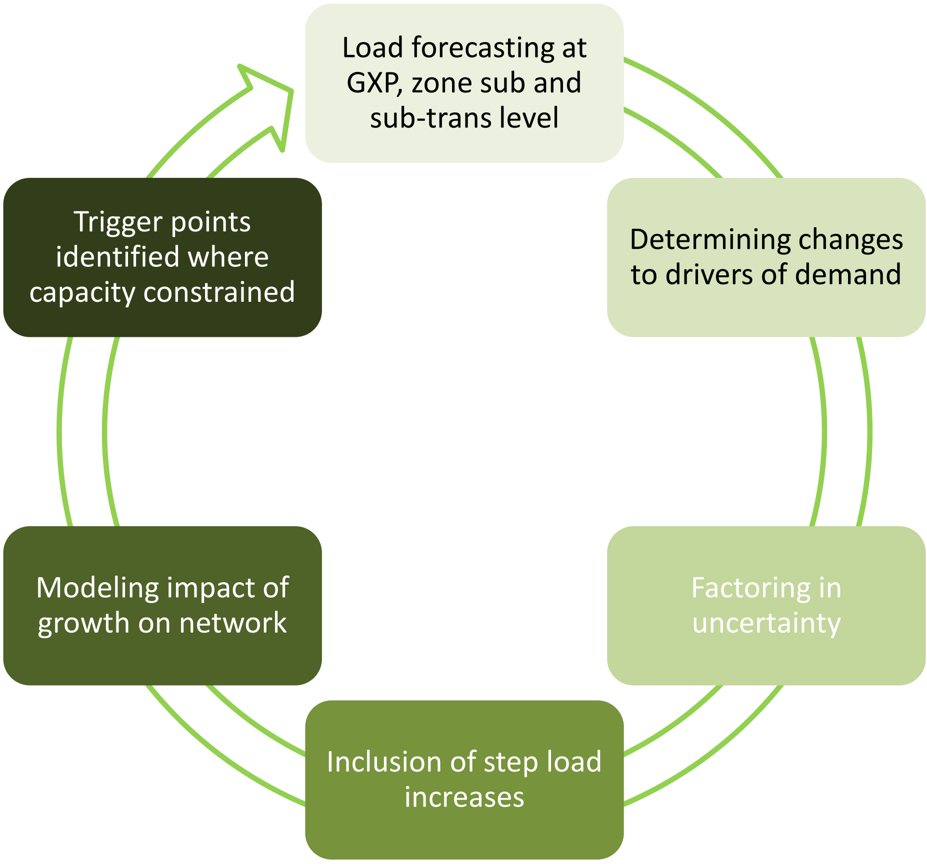
This section summarises the planning process used to determine the material Capex spend over the next year and over the next 10 years. This process is described in Figure 5.1.

Figure 5.1 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 5.2.

Figure 5.2 Situation analysis



5.2.1.1 Forecasting growth

When forecasting growth at substation and feeder level, we use a simple model that uses historic data to calculate future growth. We use a line of best fit across historic peaks from the previous 15 years[20], before adding in step load increases when we are confident these will occur.

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

[20] Data is sourced monthly from Transpower who meter GXPs and is reconciled against data from the EA's reconciliation manager.

5.2.1.2 Drivers of load growth

Load growth occurs in five distinct areas of the network. These areas are: rural, residential, industrial, commercial, and distributed generation (PV). The drivers behind load growth in each area are listed below.

Rural load growth

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

Dairying in South Canterbury often requires irrigation as the soils are 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 required (cows per hectare) to offset the large investment needed for dairy conversions. More cows per hectare means more feed required and more irrigation.

The amount of irrigation needed will vary for each farm and will depend on 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 so must make judgement calls about what land to irrigate for how long and when, unless storage is available.

Because irrigation pumps and dairy sheds require more power (network capacity) than traditional South Canterbury land uses, the recent change to dairy has meant significant network upgrades.

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

Table 5.1 Drivers behind dairy conversions

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/weak?
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 5.2 Drivers behind intensity of irrigation at farm level

Drivers behind when irrigation will occur	Effect on demand for irrigation	Strong or weak relationship
Rainfall	Negative but effect of rainfall depends on how soil moisture is affected. The first day of rain sees high demand for power as plants 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

Residential load growth

The traditional driver of residential load growth has been population growth. From 1996 till 2013 South Canterbury population growth had been 0.14% p.a. Recently, other drivers have been impacting on residential use of electricity. These include environmental restrictions on the use of open fires, the price and availability of alternate energy sources, as well as better insulation on newly built houses. The exact result of these drivers remains unclear. Heat pumps are more efficient than other forms of electric heating, but the swapping out of log fires for heat pumps has the opposite effect.

Industrial and commercial load growth

The main driver behind industrial and commercial load growth is local economic growth. We include industrial growth as step demand increase once we are confident that loads will occur.

PV growth

PV growth is driven by consumer tastes for 'greener' technology, electricity prices (as well as initial capital costs of relevant technology), and set up and maintenance costs. In the future, cheaper battery technology will encourage greater uptake.

Drivers which can reduce uptake include the recent lowering of the buyback price by some retailers, as well as hydro generation. Hydro generation does not produce greenhouse gases. This places less pressure on government to promote 'greener' forms of generation.

Solar hot water has received less media attention but could have an impact on network load in the future if PV looks less promising.

Electric vehicle growth

The global trend towards lowering vehicle emissions tethered with a traditionally high oil price has generated renewed interest in electric vehicles (EV). Some commentators believe that EVs will be economic in New Zealand by 2019[21], although the recent significant drop in oil prices may impact on the direction global car makers take in the future.

The impact of EVs on the network has yet to be modelled.

Use of multivariate models

It is important for us to identify the main drivers of load growth when forecasting. A complex multivariate model that identifies and includes drivers that have an

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

observable relationship with load growth would ideally be developed. However initial investigations into rural demand for electricity have found it difficult to show observable relationships between the most obvious drivers of irrigation (the main driver of future load growth), such as temperature or rainfall (see below). The amount a farmer irrigates their land is based on a number of variables 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.

In short, the relationship between suspected key drivers of irrigation and the amount of irrigation that occurs are considered too complex to model with any accuracy. Instead, a simple model that forecasts growth based on historic data is used, with the idea that historical complex relationships will continue as is into the future.

Where it is known that there will be a change to a key driver, such as a change to the number of consents issued, our planning team will factor this into growth forecasts once simple historic forecasts are conducted.

Use of outside consultants

In 2011 we had Sapere Group model the relationship between rainfall and irrigation. Sapere found “a weak negative correlation between rainfall and irrigation (-20%) which reflects a high degree of randomness”.

Sapere concluded by saying that due to the number of drivers on 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 we have certainty that loads will go ahead. If the step in demand is material (above $450,000), we will not proceed beyond the conception planning stage until capital contributions have been paid.

Often we are unaware of new load requirements until a customer approaches us with a request to connect. In some cases the network upgrades required for connection will take longer to plan and build than the customer has given us. To overcome this issue, we are looking at methods to inform and educate local investors of our time frames for information.

5.2.1.4 Planning assumptions and impact of uncertainty

Table 5.3 below shows how we factor uncertainty into the planning process.

Table 5.3 Significant assumptions and the impact of uncertainty on planning

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 these 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.	This 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.	This 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 line charges 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.

5.2.1.5 Use of software to model impact of growth on the network

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 are identified where capacity is constrained, by either ampacity, voltage drop, or summed network demand.

5.2.1.6 Identification of trigger points (capacity constraints)

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

If trigger points are reached, we activate one or more of a range of network development options to bring the asset's operating parameters back within an acceptable range. These options include Capex projects to extend, upsize, and renew assets within the network. Thus the capacity of our assets is adjusted to meet the new level of demand. As a natural consequence, the trigger points are readjusted to match the new operating parameters of the new or modified assets. This links closely into the discussion of asset life cycle in chapter 6.

5.2.2 Problem definition

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

When considering 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 involving changes to the transmission network can take up to five years to facilitate.

5.2.3 Prioritisation of options for meeting demand

Table 5.4 shows the options considered when capacity is exceeded or expected to be exceeded. Options are listed in order of preference.

Table 5.4 Options for when capacity is exceeded

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 to ourselves.	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.
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. The downside to this approach is that it 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 their trigger points. Distributed generation would be particularly useful where additional capacity could eventually be stranded or where primary energy is going to waste.	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. This is essentially a sub-set of the final approach described below, but will generally involve less expenditure. This approach is more suited to larger classes of assets such as 33/11 kV transformers.	By adding forced cooling.
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.

The preferred option is chosen during planning sessions with the Network Manager, senior engineers, and the Operations Manager.

We are presently implementing a software based decision making tool which will assess and balance competing demands for growth, safety and financial return to readily identify best options. This tool, combined with the experience and knowledge of our engineers, 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

When the preferred option is chosen the Network Manager, the Asset Manager, engineering and operations will include the option/project in the works plan to be incorporated in the AMP and budgets for approval by the CEO and the Board.

Projects placed into the works plan are prioritised in the order at Table 5.5.

Table 5.5 Criteria for assessing prioritisation of different options

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.
Efficiency	Projects that improve the capacity of the network to meet stakeholder needs. Criteria include: network operating performance, organisation of network assets, and improvement of the network design.
Economy	Projects that produce the best return in terms of network improvement for funds expended.

Once accepted into the Capex works plan, as listed in Appendices B and C, the project will proceed as follows in Figure 5.3.

Figure 5.3 Project completion procedure

Preliminary design	•Perform preliminary design, including evaluation of technical options, detail costing, and re-run the cost-benefit analysis if detail costs exceed those used for investment analysis.
Consent approval	•Address resource consent, property ownership, and any Transpower issues.
Detailed final design	•Perform detailed design, including the preparation of drawings, equipment and construction specifications; tender documents as necessary and procure critical major components.
Tender	•Tender out construction stage. •Award tender.
Action job	•Construction stage.
Completed job	•Commissioning stage. •Close out and debrief project after construction.
Operations	•Asset management or ongoing monitoring.

5.2.5 Review

Plans are reviewed during network meetings 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 itself is presently underway. For more information please refer to section 8.3—Continuous improvements to our asset management system.

5.3 Demand forecasts on the network 2015–2025

Demand forecasts for GXPs, sub-transmission, and zone substations assets can be found in the Major Network Asset Management Plan.

Residential demand is forecasted by extrapolating a trend line from the past 15 years of monthly peak demand at GXP level to determine historic growth. The likely impact of environmental legislation on heating, population changes, 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. This is discussed further in section 5.3.1—Inclusion of step demand increases.

Figure 5.4 Network load growth

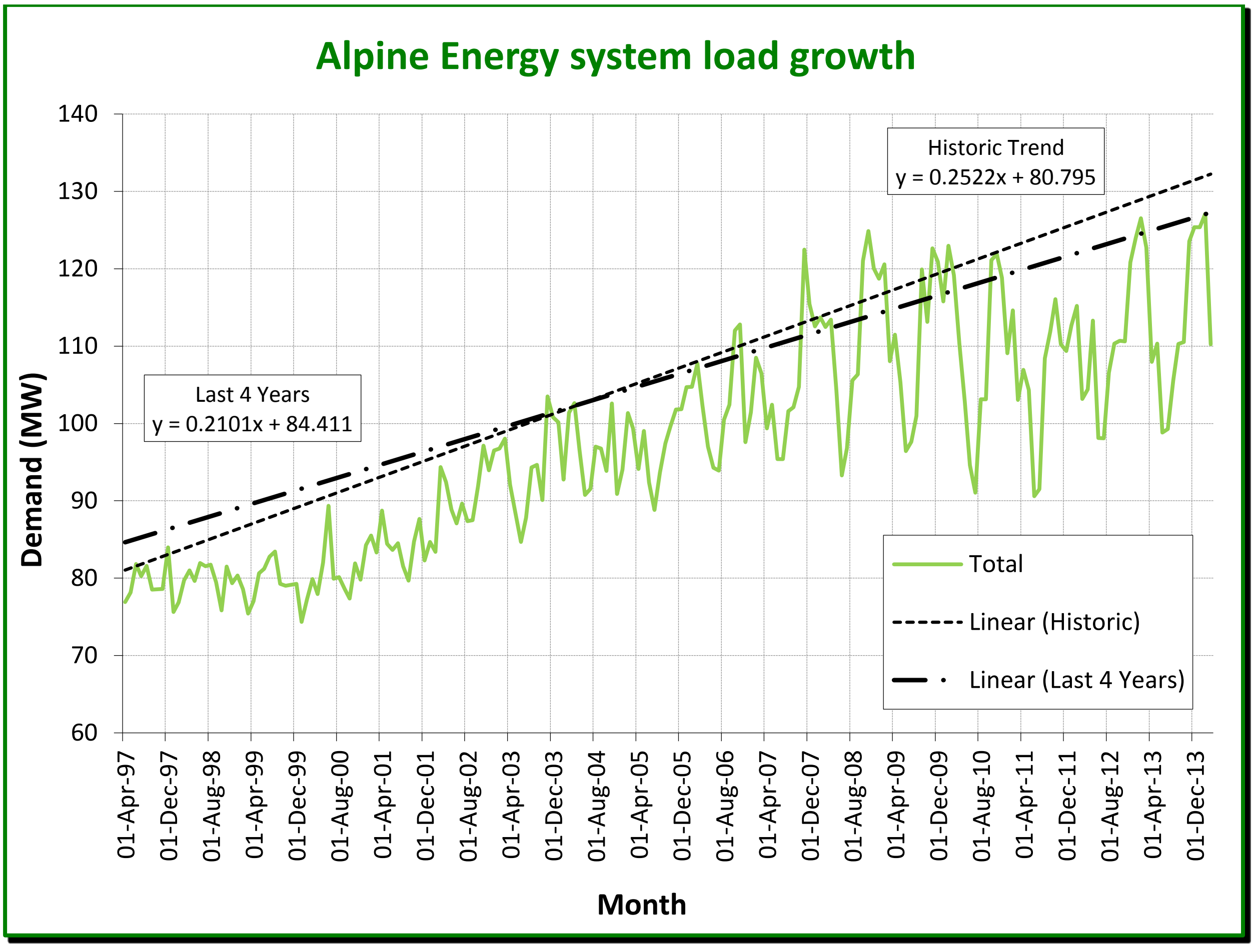


Figure 5.5 and Figure 5.6 show historical trends of anytime maximum demand and the total maximum demand growth rate for each GXP (shown by the dotted trend line in each case).

Figure 5.5 Load growth by GXP (1)

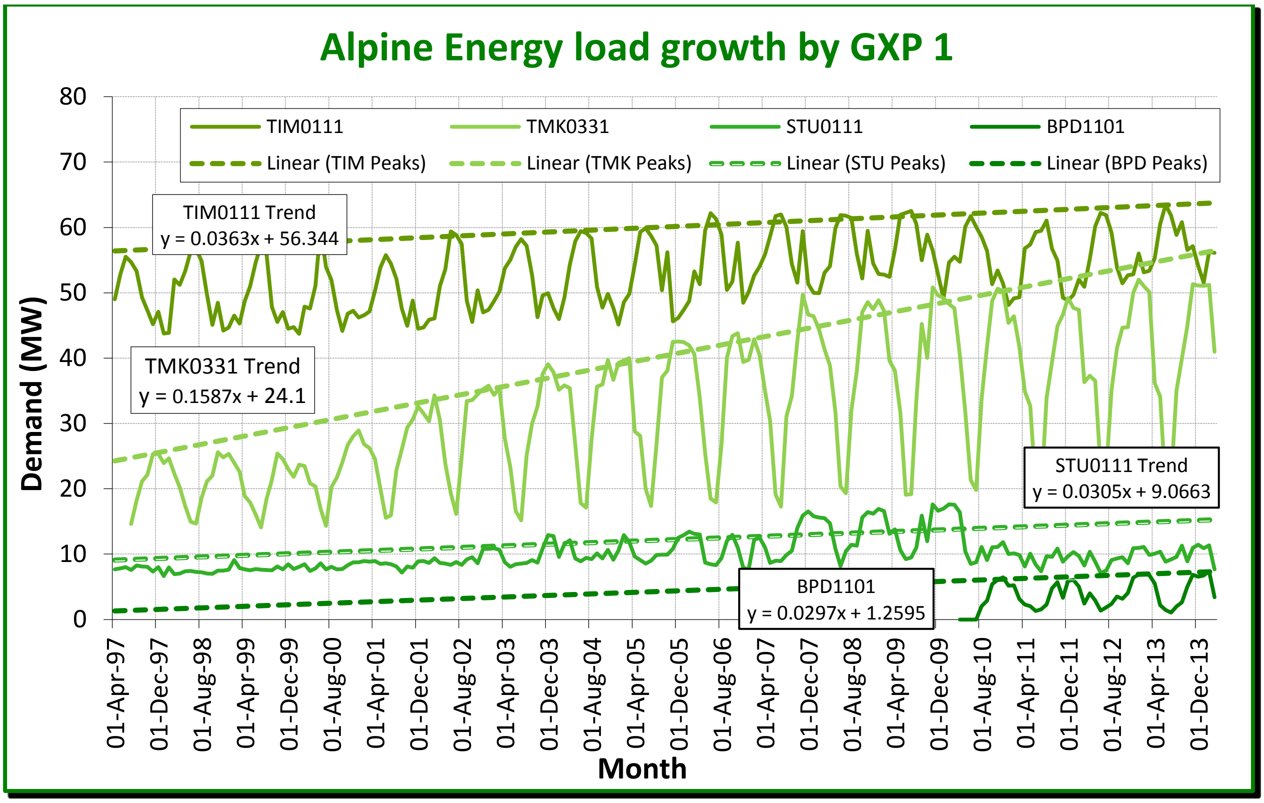
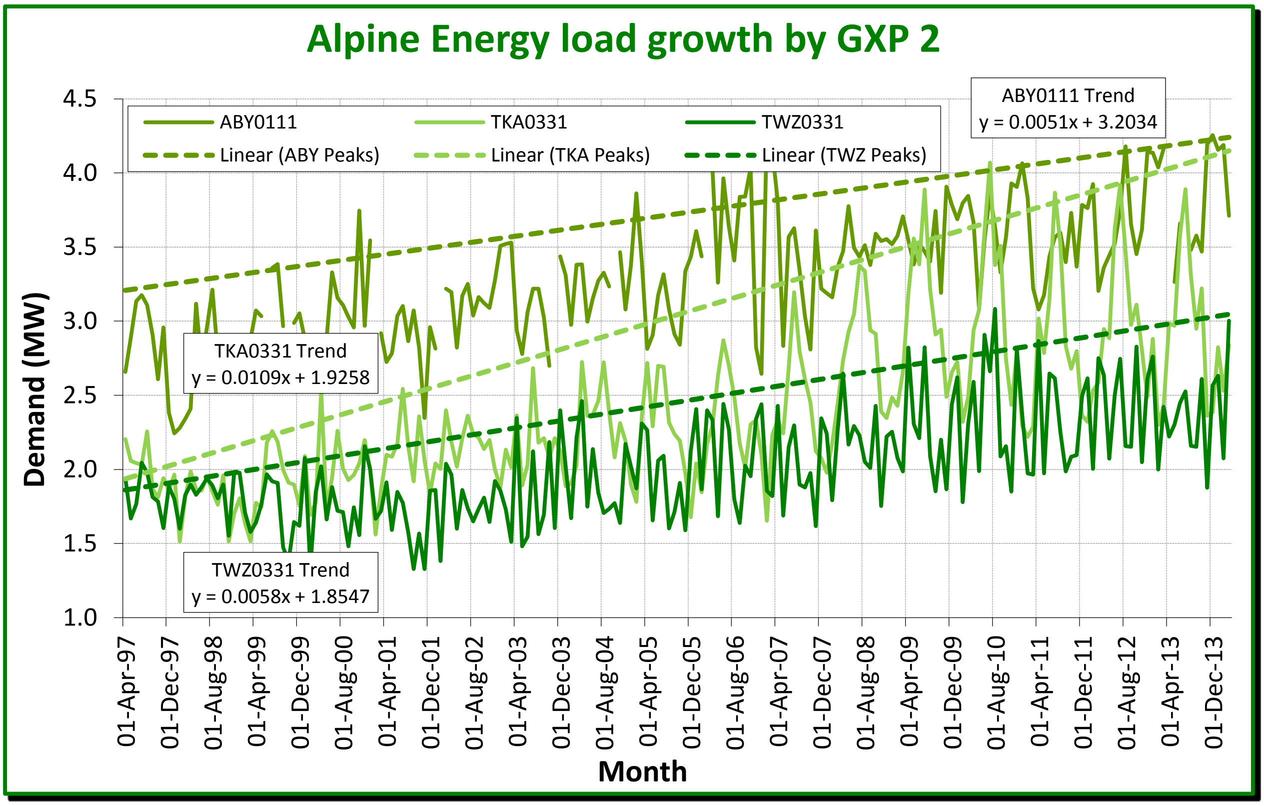


Figure 5.6 Load growth by GXP (2)



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

The data in each of the figures is summarised in Table 5.6. The figures reported in the table are current to March 2014 and are based on the highest single half hour maximum rather than average of 12 highest peaks. The trend is also taken over the last 15 years.

Table 5.6 Historic GXP demand and growth

GXP	Half hour max demand	Monthly growth (MW)	Annual growth (MW)	Annual growth (%)
ABY0111	4.074	0.005	0.065	1.591
BPD1101	7.38	0.030	0.356	4.829
STU0111	11.43	0.031	0.366	3.202
TIM0111	63.434	0.036	0.436	0.687
TKA0331	3.89	0.011	0.131	3.362
TMK0331	51.294	0.159	1.904	3.713
TWZ0331	3.004	0.006	0.070	2.317
Total	**144.506**	**0.277**	**3.328**	**2.303**

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 us by Transpower and/or industry. These are shown in Table 5.7. These step demands and above assumptions are incorporated into our load growth projections for GXPs.

Table 5.7 Projects adding step demand increases by GXP

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

Project	Demand (MW)	Year	GXP
Juice Products NZ	1	2015	TIM
Rangitata Irrigation	3	2015	RGA/TMK
Show Grounds St 1	1	2015	TIM
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

5.3.2 Estimated demand at GXP level

Once step demand loads are factored into our planning models, we can estimate demand at GXP, zone substation, and feeder level. Summaries of demand at zone substation and feeder levels are given in the sections below. Information on planning at GXP level is found in the Major Network Asset Management Plan and summarised in Table 5.8.

Table 5.8 Load growth by GXP

GXP substation (Season peak)	Forecast growth trend (Total MW MD) for the year ended 31 March										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
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
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

5.3.3 Estimated demand at zone substation level

Information on planning at zone substation level can be found in the Major Network Asset Management Plan. Table 5.9 below summarises demand growth at zone substation level.

Table 5.9 Zone substation demand growth

Zone sub	2015 MW	Ten-year rate and nature of growth	2025 MW	Provision for growth
ABY 11 kV board	4.20 (summer)	1.59% historic on ABY. Irrigation and dairying activity, residential load, small subdivision development.	5.0 (summer) 8.4 (with Raincliff/ Totara Valley)	Transpower asset under their management. Overall load not expected to breach Transpower's capacity unless Raincliff/ Totara Valley built.
FLE	2.37 (winter)	1.57% historic 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 about 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 needed to carry load which depends 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 (summer)	3.2% per year expected as TMK Residential load. Dairy and Irrigation development (not including step changes).	33.7 (summer)	Transformer upsizing required pending load split for Hunter Downs between STU and STA. 11 kV switchboard upsizing required after 24 MVA.
TEK	3.2 (winter	3.9% historic on	5.4	Transformer being changed out in 2015

Zone sub	2015 MW	Ten-year rate and nature of growth	2025 MW	Provision for growth
	/shoulder)	TEK. Residential load. Tourism development.	(winter /shoulder)	to 5/6.25 MVA.
HLB	0.2 (est.) (winter /shoulder)	3.9% historic on TKA. Residential load. Tourism development.	? (winter /shoulder)	Minimal unless lines away rebuilt. If irrigation expands toward Haldon then it is likely their supply will come from TWZ. This sub would be retained for Lilybank.
BML	0.3 (est.) (winter /shoulder)	3.9% historic on TKA. Residential load. Tourism development.	? (winter /shoulder)	Minimal unless lines away rebuilt. If irrigation expands toward Simon's Pass then it is likely their supply will come from TWZ. This sub may be decommissioned. Close in loads can be fed at 11 kV.
GTN	0.3 (est.) (winter /shoulder)	3.9% historic 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% historic 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% historic 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 about 43 MW by the end of the planning period. With careful load transfers existing assets can meet this demand and retain N-1 security.
GLD	6.1 (summer)	3.6% historic on TMK. Residential load. Dairy and irrigation development.	7.9 (summer)	Local concern may lead to a second 33 kV circuit to provide N-1 security—expect demand to grow from current demand of 6.5 MW to about 7.8 MW by the end of the planning period. AEL installed RMU to break rural load off CBD—this will improve reliability and allay some concerns.

Zone sub	2015 MW	Ten-year rate and nature of growth	2025 MW	Provision for growth
RGA	9.8 (summer)	3.6% historic 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 about 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% historic; some steps expected to come from residential growth, heat pump uptake, and industry growth (Washdyke).
TIM CBD	39 MW (winter)	0.7% historic 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 this 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 about 9 MW by the end of the planning period. Acceptable security for the major meat processing works supplied from this site 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% historic 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 at STU and BPD.	76 (summer)	Build to suit 10 year forecast.

5.3.4 Estimated feeder demand

Due to the large number of 11 kV feeders, the maximum demands are listed in Appendix A—Summary of 11 kV feeders.

5.3.5 Effect of GXP forecasts on supply security

The continuing load growth on the ABY, BPD, STU, TMK, and TIM GXPs, as well as forecast load increases at TKA and TWZ, will see capacity constraints within the planning period of the AMP. These are explained further in the Major Network Asset Management Plan. A summary of how we provide for growth is shown in Table 5.10.

Table 5.10 Rate and nature of GXP growth and provisions made

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 GXP investment
TKA	Med – subdivision and tourism business	Upgrade zone substation
TMK	High – rural and industrial	GXP investment
TIM	High – industrial / commercial	GXP investment
PAR	High – dairy and irrigation	Zone substation and sub-transmission investment
PLP	High – dairy and irrigation	Zone substation and sub-transmission investment at Totara Valley
TWZ	Med – rural and subdivision	GXP investment

5.4 Effect of constraints on planning

Network constraints are more fully described in the Major Network Asset Management Plan. A summary of constraints is found in Table 5.11.

Table 5.11 Network capacity constraints

Constraint	Description	Intended remedy
Waimate Area—Holistic	Lack of capacity for BPD, STA, STU.	Work with NWL and Transpower on the Lower Waitaki Project to ensure capacity is made available by 2018.
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

Constraint	Description	Intended remedy
		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 NWL and Transpower on the Lower Waitaki Project to ensure capacity is made available by 2018.
BPD GXP Supply Security via transformer	Upgrade N security to N-1.	As the demand grows install second transformer (timing uncertain—review size of ODL and farm extensions, probably 2016).
STA, WTE	Lack of capacity for HDI.	Lack of capacity in 11 kV network to supply HDI. Provide a solution as part of Transpower's Lower Waitaki Project for 2018.
Timaru Area—Holistic	Lack of capacity in 220/110 kV interconnectors for ABY, TIM, TKA, and TMK.	Request Transpower upgrade their 220/110 kV interconnecting transformers, or construct bussing point at OAI with new GXP at Clandeboye to off load 40 MW from TIM, or construct double cct 220 kV line ISL-LIV cct to TMK and offload TMK from 110 kV lines and TIM bus.
TIM GXP Supply Security	N security to return to N-1.	Replacement of 110/11 kV transformers from single phase to three phase with adjustment in rating will lift N-1 capacity. Physically underway. Long term new investment in transformers—Transpower discussion for 33 kV solution or hybrid 11 kV and 33 kV. 80 MW TIM 11 kV load trigger point.
Highfield (TIM2952) feeder loading	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	Heavily loaded feeder.	Long term establish West End substation off 33 kV TIM GXP (timing uncertain) or interim move some load onto Highfield once some Highfield moved to Redruth 1 feeder ex NST substation.
Levels feeder (TIM2852) loading	Heavily loaded feeder.	Long term establish West End zone substation off 33 kV TIM GXP (timing uncertain).
Mountainview feeder (TIM2712) loading	Heavily loaded feeder.	Long term establish West End zone substation off 33 kV TIM GXP (timing uncertain).
Washdyke feeder loadings	Heavily loaded feeders.	The recession has temporarily slowed growth in the Washdyke area, but this is picking up again. 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

Constraint	Description	Intended remedy
		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-trans in Iodine presently underway but 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).
Temuka Area - Holistic	Lack of capacity for TMK 33 kV GXP load.	Work with Transpower on upgrading supply assets. Request Transpower upgrade their TIM 220/110 kV interconnecting transformers, or new investment in 110 kV line, 110/33 kV transformer and 33 kV switchboard upgrade—Transpower discussion (timing uncertain), or possibly establish new GXP off a proposed 220 kV OAI bussing point to offload TMK GXP or possibly establish new TMK GXP off the ISL-LIV 220 kV circuit.
TMK GXP Supply Security	Load constraint over 60 MVA transformers, 70 MVA on lines, 71 MVA 33 kV switchboard.	Request Transpower upgrade their TIM 220/110 kV interconnecting transformers, or new investment in 110 kV line, 110/33 kV transformer and 33 kV switchboard upgrade—Transpower discussion (timing uncertain), or possibly establish new GXP off a proposed 220 kV OAI bussing point to offload TMK GXP or possibly establish new TMK GXP off the ISL-LIV 220 kV circuit.
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.
FLE 33/11 kV zone sub	Regulator capacity 2 MVA Transformer capacity 3 MVA.	Present peak loading up to 2.4 MVA, install larger regulator or OLTC transformer (2014) ex pre-used PAR. Awaits mobile substation.
Otaio feeder regulation (STU)	Voltage constraint at end of feeders.	New voltage regulator installed at Cup and Saucer and loaded with capacitors, feeder at

Constraint	Description	Intended remedy
and St Andrews feeder regulation (PAR) Both to same area—feed from both ends		end of capacity from both STU and PAR. Look to load up PAR's Holme Station feeder to offload PAR feed toward Otaio. Off load Dairy Factory 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—? 2018).
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 2013/14 plan but no locations available in CBD.
Mt Studholme Feeder (STU)	Voltage constraint at end of feeders.	Mt Studholme needs chokes on existing site to suit ripple 2014/15 plan.
STU ripple plant	Ripple signal attenuation will occur with Transpower's new transformers.	Procure new 11 kV cell when Transpower actions project.
Ikawai (BPD)	Voltage constraint at end of feeder.	Build second parallel feeder (on going). Waiting on 33 kV line toward Pub Rd so circuit can share poles.
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.

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 below.

5.4.1.1 Coastal environment constraints

Part of our network is built within a coastal marine environment. This environment is hostile to most components used in an electricity network and is the principal driver of any accelerated maintenance programmes required to maintain service to consumers. Where possible, assets designed for this environment are used. For more information please refer to chapter 6.

5.4.1.2 State highway constraints

Proposed changes to utility access to road corridors by road controlling authorities has meant some rebuild projects along state highways have not proceeded. The new requirement of pole positions being nine meters from the road edge would result in lines being constructed on private land with associated easement negotiations and costs. This subject has now been escalated to a national level where the interests of all parties are being balanced. This is likely to result in utility access being restored. With a large amount of our backbone network built along the dominant state highway traffic routes, there is considerable risk of not gaining approval from the road controlling authorities to replace works at end-of-life. While re-poling like for like can occur, often conductor sizes increase with the rebuild, requiring new pole positions to cater for changed span lengths. Shifting an overhead asset off the highway (if private land owners' approval can be gained) can cause significant additional risk and cost.

5.4.1.3 Available resourcing constraints

Resources remain a constraint on undertaking planned work. Growth in South Canterbury has focused efforts on capital investment in building new network assets to meet consumer needs. This has meant that some maintenance work has been carefully prioritised with the most urgent maintenance being completed while minor maintenance is deferred pending available resources. External resources are also stretched with work on their local networks. Attracting external resources to work remotely attracts a premium which needs to be balanced against the value gained from immediate completion of the work or rescheduling the work to occur at a more affordable price. Hence Capex and Opex programs must remain flexible to advance when consumer needs are suddenly unveiled or be delayed when constraints in completing projects make it unviable to complete within the budget.

5.4.1.4 Land access agreements and easement constraints

Access to private land is becoming more difficult in areas where land owners may not receive any direct benefit from the new works. There is now a substantial cost and lead time to negotiate land access agreements and formal electricity easement agreements which affect the timing of establishing new works.

5.4.1.5 Resource consents

The Timaru, Mackenzie and Waimate District Plans state that for projects over 50 m, no new overhead line or line voltage or conductor upgrade can commence in commercial or residential areas unless resource consent is approved. This involves consultation with every landowner that the line is in view of or passes over.

5.5 Criteria to consider when planning

Planners must consider the following criteria when assessing the options available to meet forecasted load. These criteria will more formerly match our asset management strategy when we fully implement the Network Development Plan prioritisation process (NDP), discussed in section 5.10—Continuous enhancement, on page 153.

5.5.1 Non-network options

One area where we can leverage energy efficiency is in non-network solutions to peak loading, particularly with the use of demand side management. Our aim is to continually improve the utilisation and availability of existing network assets. Technological solutions have been implemented to improve operating efficiency and these have included the installation of a SCADA system, microprocessor substation protection relays, line fault indicators, and a load management system.

Decisions on asset replacement versus continued maintenance or refurbishment is subject to economic analysis, to determine the most cost effective option. In some cases, this may result in the partial replacement of an asset.

Assets removed from the network due to upgrading or refurbishment are assessed to ascertain their condition and, where possible, are reused elsewhere on the network.

Consumers with sensitive loads have considered installation of a standby diesel generator to provide a non-interruptible supply. Discussions have commenced with one consumer to consider using their stand-by generation to supply the network under certain circumstances. This distributed generation initiative is expected to be a more common approach in future network planning. However, the UK security standard P2/6 doesn’t allow for all of the distributed generation to contribute to security of supply, which is a cautionary point to consider.

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 further spare transformer against the need for managing the planned loss of supply (LOS) for ABY and TKA GXPs for two to five yearly Transpower maintenance has influenced plans for one national mobile substation for Transpower (110/33/22/11 kV). We are also in the process of building one (33/11 kV) mobile substation which could double as an emergency back-up (for faults) and as a temporary second transformer (for avoiding planned outages that would otherwise be required when maintaining single transformers).

Other risk treatment supports the use of distributed generation as a method of limited backup supply to mitigate single transformer failure or allow work on a mid-section of overhead line, thus keeping the far end live.

We have commenced a project to have two 500 kW portable generators for emergency standby duty or voltage support duty to maintain service standard expectations by our consumers. These can run separate at 400 V, ganged at 400 V, or be stepped up to 11 kV.

Photograph 5.1 One of our mobile generators

5.5.2 Demand side management

Demand side management tools consist of contracting consumers with electric hot water storage units to place these on a controlled rate tariff which allows load interruption at peak times. This lowers the peak demand on the network and through the transmission grid. Retailer pricing in some cases has eroded the price signal between controlled and non-controlled rates, tempting consumers not to abide by the network policy for control of electric hot water storage heating. A clearer pricing signal has been provided to consumers from the lines company independent of retailer pricing which has restored the use of controlled hot water heating.

Further work will be required to consider demand side reduction programs for interruptible consumer load. Irrigation is an area, like electric hot water storage heating, that can potentially have supply curtailed during a peak demand period and still meet the consumers' irrigation expectations for the balance of the period where control is not exercised. An incentive tariff would need to be developed to provide irrigators with a price signal which warranted placing irrigation load onto a peak demand control at times when the network required load curtailment.

This would need to be discussed with the irrigation industry as irrigation systems have become very sophisticated with computers controlling the rate of spray irrigation against the soil type and soil 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 the opportunity for demand side management initiatives. These discussions were commenced on a public good/voluntary basis and would need to be developed onto a commercial footing to provide the correct incentives for regular load shifting opportunities.

5.5.3 Options to meet security

A key component of security is the level of redundancy that enables supply to be restored independently of repairing or replacing a faulty component (the spare tyre philosophy).

Typical approaches to providing security to 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 to allow one to cover the load of the other in the event it trips out on fault.
- Provision to back-feed on the 11 kV from adjacent substations where sufficient 11 kV capacity and interconnection exists. This firstly requires those adjacent substations to be restricted to less than nominal rating and secondly requires a prevailing topography that enables interconnection.
- Use of local generation (OPU Dam) or portable diesel generator set(s).
- Use of interruptible load (such as water heating or irrigation) to reduce overall load.

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

5.5.3.1 Prevailing security standards

The commonly adopted security standard in New Zealand is the EEA Guide for Security of Supply which was recently revised and reissued in August 2013. It 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 i.e. it stated that this amount and nature of load will have this level of security with no consideration of individual circumstances.

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

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 any use from a security perspective, local generation would need to have 100% availability which is unlikely from a reliability perspective and even less likely from a primary energy perspective, such as run-of-the-river hydro, wind, or solar. For this reason, the UK standard 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 are found in the Major Network Asset Management Plan.

5.5.4 Issues arising from estimated demand

Significant issues arising from the demand forecasts in this section are found in the Major Network Asset Management Plan.

5.5.4.1 Transpower estimates and GXP new investment estimates

The expansion of GXP capacity can either be funded by us or Transpower. At this stage, it is anticipated that GXP investment will be funded by Transpower and the costs passed through to consumers in the standard transmission charge and treated as 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 of decreasing asset utilisation, we expect the asset utilisation to increase in the dairy and irrigation areas as kWh throughput increases faster than maximum demand.

This has an effect of increasing overall asset utilisation. One disadvantage resulting from irrigation load during seasons of continual drought is the flat and constant load demand profile at elevated ambient temperatures. This provides no thermal relaxation for the distribution assets. It also makes it difficult to arrange access to assets for replacement or maintenance without interrupting irrigation and dairy milking cycles.

5.5.6 Impact of climate change on planning

During 2013 we experienced weather events that have not been seen for over 30 years. These included flooding, wind and snow storms. A recent report from the Prime Minister’s Science Advisory Committee on the localised impacts 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 IPCC issued its Fifth Assessment Report—Climate Change 2014. In regard to New Zealand, they stated the following[22].

- "New Zealand's predominantly hydroelectric power generation is vulnerable to precipitation variability. Increasing winter precipitation and snow melt, and a shift from snowfall to rainfall will reduce this vulnerability (*medium confidence*) as winter/spring inflows to main hydro lakes are projected to increase by 5 to 10% over the next few decades. Further reductions 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 winds".
- "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 risks to transmission".

5.5.7 Description of equipment used for capital expenditure

The following criteria are used to determine the capacity of equipment required when developing options to meet load growth/capacity requirements. This helps to standardise design and equipment used which leads to cost efficiencies. For more information on standardised equipment see 0.

5.5.7.1 Reliability and security of supply

The security standards that may be adopted by us follow the issue of the revised EEA *Guidelines for Security of Supply in New Zealand Electricity Networks* which mean that on the sub-transmission system we will strive to achieve an N-1[23] security level.

It is difficult setting a MW level or ICP number at which N-1 supply security is required. This is on the network 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 criteria that are evaluated include 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.

[22] Reference: IPCC's web site at: www.ipcc.ch/report/ar5/wg2/.

[23] This level of security implies that the loss of a single element would not result in the interruption of supply.

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 adopted within this plan.

Existing security levels are listed in the Major Network Asset Management Plan.

5.5.7.2 Voltage regulation

The capacity of equipment that may influence voltage regulation is chosen to ensure we comply with the electricity regulations to control the voltage within ±6% of the declared potential, except for momentary fluctuations (i.e. voltage dips).

Equipment includes: power transformers fitted with On Load Tap Changers (OLTCs), voltage regulators, capacitor banks, distribution transformers fitted with OCTC tap 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 that we developed with the assistance of other electricity distribution businesses.

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

Photograph 5.2 VSDs on irrigation pumps can cause harmonic issues

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 from switchboards, cable and cable screen ratings, surge arresters, ring main units, O/H line D/O fuses, and so on. In addition, all new switchboards are installed with arc-flash protection schemes.

We worked with Transpower to reduce the TIM fault levels. For example, earth faults at TIM were reduced when NERs were installed in 2012, and phase fault levels were lowered when the three new supply transformers began operating with two in service and one on hot standby in 2014. In addition Transpower chose very high transformer impedances in an attempt to lower fault level before the idea was put to Transpower to run on two of three units.

Other substations will be cared for as they are upgraded with larger supply transformers.

5.5.7.5 Power factor

The closer the power factor is to 1, the more optimal the infrastructure is utilised. We are achieving this through our new connections policy and technical requirements for a new plant to be connected to the network. A combination of voltage regulators and capacitor banks is used on the network to improve voltage levels along loaded feeders, the capacitors giving added benefit by compensating for reactive power losses or, alternatively, improving the network power factor. The sizing of these capacitor banks is important since over-compensation can lead to HV during light loading conditions where potential rise is seen to become 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 projects planned for the next 12 months are found in Appendix B on page 245. Capex projects planned over the next 10 years are found in Appendix C on page 247.

5.6.1 GXP, zone substation, and sub-transmission

Please refer to the Major Network Asset Management Plan for information on major assets from GXP to zone substation level including sub-transmission. Please also refer to Appendix B and Appendix C for our development projects planned or underway. Photograph 5.3 below is of the ABY GXP.

Photograph 5.3 ABY GXP

5.6.2 Voltage support

This section describes network plans for voltage support.

5.6.2.1 Line regulators

Line regulators have become increasingly important to provide potential support in lengthy light conductor 11 kV distribution lines. Most lines were built in an era of dry farming, but with the rise in dairying and irrigation, the loads have exceeded the original design parameters of the lines. It is very costly to re-conductor lines as this often leads to new poles at shorter span lengths. Rebuilding can be complex if the lines pass down state highways with the new build having to be 9 m from edge line. If the lines pass over private land, negotiations for electricity easements are required.

Since 2008 a number of regulators have been installed and new installations are done on an as required basis. The exact requirements are difficult to determine until loads are announced as it depends on where the load growth eventuates. Therefore, an annual fund will be required for suitable voltage regulator installations to match the growing load.

5.6.2.2 Line capacitors

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

A lot of the loads connected are requested to be power factor corrected so they run at 0.95 lag or better. Often this is not the case; however, capacitors provide high level correction, thus allowing losses due to reactive power supply to be minimised.

Capacitors are passive devices so require minimal maintenance, whereas a regulator is on a quadrennial inspection/maintenance cycle. They are generally more economical to install than regulators. Line capacitors can generally be connected via a simple ABS and set of DOs.

Capacitors do present voltage rise problems when the network becomes lightly loaded, so careful planning and design is required to ensure that the capacitors 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 noted capacitors to attenuate ripple control systems. We have standardised our 317 Hz ripple. It was suggested that the frequency would be low enough not to be affected by the capacitors. Practice has shown otherwise; at least one site needs blocking chokes added and two others need review. The older 500 Hz systems at ABY and TEK are more likely to have the signal attenuated.

Capacitors are in high demand globally; they need procuring six to eight months in advance so do not ideally suit AMP cycles coupled with the random load growth (as commented on in the line regulator section above). It is recommended that while load growth is prevalent, sufficient new sets of each 1 Mvar and 0.5 Mvar are procured and stored for the dairy off season each year in readiness for the work programme for the next few years. There are presently 2 x 1 Mvar and 2 x 0.5 Mvar in store. A few are out of service on poles; to fix, chokes are needed.

5.6.3 Line reclosers

Our network has two reclosers that are at the end of their economic life. Two 'ball and chain' type reclosers remain that are due for replacement, both M142 and M210 will be replaced by winter 2015. Some more modern types have not been as reliable as is ideal— consideration is being given to their future.

Inclusion of more 11 kV line reclosers in the network allows greater segregation of feeders during faults and a reduction in SAIDIs. Research will determine which feeders have the highest fault incidence leading to the best application of reclosers.

5.6.4 Distribution cables

New feeder cables will be required for substation work at STU. The detail is 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 future fault damage due to interphase faults in cable boxes. Transition joints were required in the ground— this arrangement seems a robust system to adopt as standard to minimise risk within switchgear cable boxes.

It is proposed to install a new feeder in GLD to split the CBD/business area load, this more than likely will be cabled.

Various undergrounding projects are being carried out in the various districts. Some of these include 11 kV assets.

5.6.5 Protection, control, and measurement

We have a mix of protection assets installed. Recent substations have had microprocessor equipment like SEL and MiCom installed. These technologies have a nominal life of 20 years.

There is a range of static protection like ABB Combiflex and SPACOM. This too has a nominal 20 year life. The replacement of some of these 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 nominally have a similar life (40 years) to that of the switchgear in which it is installed. As switchgear is upgraded and then the protection is replaced, some 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 differential protection with signalling will be required. Both these systems will have certain requirements for communications systems either fibre-optic cable 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. This will be set to detect LV bus bar faults and provide clearance in 0.5 seconds. This is about the same time delay as the fast bus blocking schemes adopted in more recent times. It is a simpler scheme so should reduce the number of human element 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). This has been adopted with the upgrades at NST and GRM.

Arc flash detection (AFD) equipment has been installed on recent switchgear at RGA, NST, and GRM to work in combination with current check to clear arcing faults within the switchboard. It is proposed to retrofit this type of asset 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

With the introduction of centralised control, local manual control of zone substation equipment by field operators is being complimented by centralised remote control by control room 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 has commenced concentrating first on making the recloser controllers ready for easy remote connection.

5.6.5.2 Measurement

As with the protection relays, there are different methods of measurements being 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 including:

- Tait VHF and two bit alarm systems
- Tait 300 UHF radio connecting Conitel protocol RTUs and Leeds and Northrup RTU50 DCIU
- Tait 300 UHF and digital radio connecting Abbey RTUs to ripple plant
- Fibre Optic cable routed and switched to SEL communication processors to connect directly to SEL relays
- Digital UHF radio routed and switched to SEL communication processors to connect directly to SEL and Micom relays.

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

5.7 Material capital expenditure projects

This section describes and details the justification for our material Capex works plan for the next 12 months. Material Capex includes all Capex projects with a total spend of more than $450,000.

For discussion on how our target levels of security will be affected by these projects please see section 4.4.5 Ten-year reliability targets, on page 98.

All Capex planned for the next 12 months, including both material and non-material Capex, is found in Appendix B on page 245.

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: Waihao Downs feeder

This project will see the construction of an overhead distribution feeder from our Bells Pond substation to the corner of SH82 and Pikes Point Rd, to supply the new substation to be constructed for the Waihao Downs Irrigation Company. Sections of the line will be constructed as a double circuit to accommodate an existing feeder along that route.

Justification

This is a chargeable project and the irrigation scheme will pay for it in full. In order to supply the required power to the scheme, new infrastructure must be built since the existing infrastructure in the area does not have the required capacity.

Alternative options/non-network solutions

A couple of options have been considered in the planning stage which included supplying the additional load at 33 kV or 11 kV. The 33 kV option would have allowed future extension and load growth but at a price. The irrigation company opted for the 11 kV supply option due to lower costs as well as the uncertainty of the second possible stage of this project.

A non-network option of using diesel generators was discussed but the client decided against it. Some members of the scheme have used this form of power supply on individual farms, but have recently changed to network supply. We can only assume this was done due to the costs in running diesel generators. It is also our understanding that water will be pumped for irrigation through summer and well into autumn to ensure moisture levels are appropriate for planting winter feed/crops.

5.7.2 Project name: Pareora sub-transmission lines reconductor

This project comprises the upgrading of the existing Mink overhead conductor to Iodine. There are two 33 kV feeders supplying Pareora substation from Timaru substation. The lengths of these feeders are approximately 16 km each. This upgrade can only be done during Silver Fern Farms (meat works) off season which is annually over September. The project also aligns with the upgrade of the substation which comprised new 33 kV switchgear and two new 9/15 MVA transformers. The project spans four years this being the fourth and last year.

Justification

These two feeders supply the Pareora substation. The major load connected to this substation is Silver Fern Farms (SFF), who is our second largest customer. Line capacity is restricted to 6.8 MVA and with a peak load of 10 MVA, N-1 network security is not achieved. With the recent upgrading of the transformers, this line upgrade would ensure N-1 security to our second largest customer. The nature of the processing at SFF is such that a loss of supply would result in lost product due to the requirement of freezing and cool stores.

Alternative options/non-network solutions

There are no alternative options to ensure N-1 security.

5.7.3 Project Name: New subdivisions and extensions

New connections, subdivision and extensions make up some 18% of our Capex budget. It is based on recent expenditure to realise new connections and extensions to our network, and is mainly driven by irrigation supplies and dairy conversions. This is mostly chargeable work for which the costs 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 of additional load but this will only happen if there is absolutely no spare capacity in the network to supply such load. This would then initiate a network upgrade if one had not already been planned.

5.7.4 Project name: Ring main unit replacement

We have embarked on a program 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 which are difficult and expensive to re-locate.

Justification

The Andelect type RMUs have a history of failures and they have been systematically replaced by the industry as a whole. The health and safety concerns around these switches are the main cause for the replacement program. We are also looking to replace most of our oil filled RMUs. Health and safety, age, and condition are the main drivers. When oil filled equipment fails, a fire is always a possibility which results in more 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 spatial requirements are more due to increased sizes of this type of equipment which makes change-outs more complicated and more costly.

Getting rid of these switches without replacing them is not an option. These switches allow the network to be configured and operated in a manner that maximises supply reliability. Without them we would not be able to meet our quality obligations under the regulatory regime.

5.7.5 Project name: Underground cable upgrades

Projects in this category are comprised of growth and replacement types. We have embarked on a program to upgrade and replace all the Lucy type link boxes on our network. The expenditure on these projects totals 6% of our Capex budget.

Justification

The Lucy boxes on our network have had lots of problems over the last years. Overheating of connections can lead to fires and access to these connections is problematic due the inability to off load these boxes to other parts of the network, as well as the fact that they are mainly located in the walkways in from of the shops in the CBD.

The replacement of these boxes also allows us the opportunity to make provision for the connection of standby generation—this will allow access to other parts of the network for planned maintenance without disrupting supply to consumers. In addition, the replacement link boxes are specified to allow the off-loading of circuits from our underground substations for planned maintenance, which is extremely difficult today.

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 more extensive damage and reduced reliability of supply.

5.7.6 Project name: Overhead to underground conversions

The aim of these projects is to remove existing overhead lines from private land.

Justification

Access to these overhead lines for maintenance and during network emergencies is difficult, which translates into increased outage times and reduced reliability.

The undergrounding will improve the risks associated with overhead lines across private land. In a number of cases, these overhead lines are traversing dwellings.

Alternative options/non-network solutions

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

5.7.7 Project name: Timaru substation 33 kV upgrade

This project is to upgrade the existing 33 kV infrastructure at Timaru substation. It covers the 33 kV switchgear and associated protection.

Justification

There are currently no incomer circuit breakers and the existing equipment is old (1960s vintage). In addition, the protection scheme is not to industry best practice and protection grading is problematic.

Alternative options/non-network solutions

The status quo cannot be supported based on our recent reliability statistics.

In total, four options have been evaluated. Two outdoor switchgear options use different makes and types of switchgear, and two indoor switchgear options also use two different types and makes of switchgear. In the evaluation of costs, constructability, maintainability, and life cycle costing (including spares holding) was taken into consideration.

5.7.8 Project name: Hunt Street substation protection upgrade

This project is to upgrade the existing feeders' electronic protection relays and migrate communications to the new fibre network from the current 485 communications system. The projects was started in the 2014/15 regulatory period and will continue into the 2015/16 regulatory period.

Justification

The current electronic protection relays are more than 20 years old which, according to industry best practice, is at the end of their life. Since the switchboard is 1984 vintage and in good condition, replacement would be 10 to 20 years away, which necessitates the need for new modern protection relays. This will also improve protection grading margins and performance since Hunt Street substation would be the last CBD zone substation to be upgraded with modern protection.

Reliability and performance of protection and SCADA will also improve with the migration to the fibre communications network.

Alternative options/non-network solutions

To do nothing is not a responsible option since it would go against accepted industry practice to replace electronic relays every 20 years. Not to migrate communications to the new fibre network results in increased maintenance costs in terms of maintaining two communications networks. Fibre communications is the future and has superior performance and reliability.

5.7.9 Project name: Waihao Down Irrigation substation

This project is to establish a new substation on the corner of Pikes Point Rd and SH82 for the Waihao Downs Irrigation scheme main pump station. The project is fully chargeable and funded by the Waihao Down Irrigation Company which is a subsidiary of the Morven-Glenavy Irrigation Company. The substation will comprise three ring main units supplying three 1.5 MVA ground mounted distribution transformers. The power supply is to run six 500 kW water pumps that will elevate the water through a 0.9 m diameter pipeline some 120 metres to a storage pond. From there, additional pipelines will distribute the water in the Waihaorunga area.

Justification

Demand growth due to the establishment of the irrigation scheme.

Alternative options/non-network solutions

We evaluated two options—namely a supply at 11 kV and 33 kV respectively. The latter would ensure distribution network capacity into the future if/when the currently under discussion, but not yet planned, stage two of the project happens. Due to budgetary constraints, however, the client decided to opt for the 11 kV supply option.

A non-network option, as detailed in the Waihao Down Feeder projects above, was considered.

5.7.10 Explanation for Material Variance from 2013/14

The proposed Capex budget in 2013/14 for the 2014/15 year was $10.825 million. The budget now is $13.667 million. The reasons for this are:

- OH line budget for Waihao downs increased
- New budget for irrigation sub-station
- Work at TIM deferred for this year
- OH to UG and UG budget increased
- New and replacement RMU's budget increased

5.8 Material non-network capital expenditure

This section describes material non-network Capex projects. As with material network projects, material non-network projects are those projects over $450,000 in constant (real) terms. Our 10-year non-network forecast expenditure can be found at Table 1.3 at page 10.

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 $3,500,000 -$4,000,000 per annum to around $59,000 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 and technology and are investing $500,000 annually 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 GIS

Our ICT team is developing software and processes to provide:

- one source of truth for geospatial information of assets
- a fit for purpose and fit for use facility to identify assets to ensure compliance with the Electricity (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 purpose—both business as usual (BAU) and emergency use (not including switch or isolation statuses)
- easy reporting on assets types for maintenance purposes
- asset details with connections to proposed asset management system to allow New Connections to design and plan new extensions
- a single source of truth along 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, and so on.

5.8.2.2 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; maintain this 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.

5.8.2.3 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 which works in close proximity (physically and culturally) to our preferred contractor, NETcon, 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 our contractor NETcon to determine the following year's works programme. During this stage, 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 works programmes, we meet fortnightly to discuss such topics as resourcing, timing, and expectations. Meeting minutes are held by our Network Manager.

Our informal approach to relationships with NETcon has served us well in supporting our asset management planning and decision making. However, we believe an Alliance Agreement between ourselves and NETcon will help to enhance asset management systems and processes.

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 which meets the demands of our stakeholders for safe, efficient, reliable, and cost effective energy delivery. Of importance is the need for targeted expenditure which does not lead to over-investment in the network.

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

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

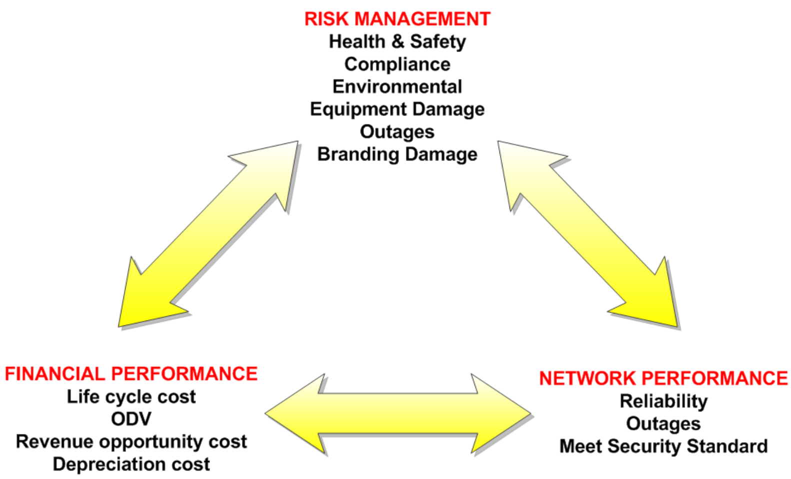
5.10.1.1 Industry liaison team

The aim of this group 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, and so on. An area which causes us concern is the lack of notice given by consumers to allow us to develop assets for their use, which makes forward planning uncertain. That is, consumers will often not release their plans to us until late in the process (possibly because of commercial sensitivity), leaving us with 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. This is shown graphically in Figure 5.7 below.

Figure 5.7 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 their level of risk to:

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

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

To ensure a structured decision making process, the AHP is applied to all of our Capex projects. Table 5.12 describes the areas of planning for which criteria are developed.

Table 5.12 Risk assessment criteria for planning

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)

6. Life Cycle Asset Management Planning

6.1 Introduction

This chapter 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); which are 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 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
- suppliers'/manufacturers' recommendations for their equipment
- maintenance pegged to industry best practices and evolution of same
- field experience with operation and maintenance of the plant in the network
- age of plant.

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

Table 6.1 Linkage between the SCI and planning criteria and 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

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

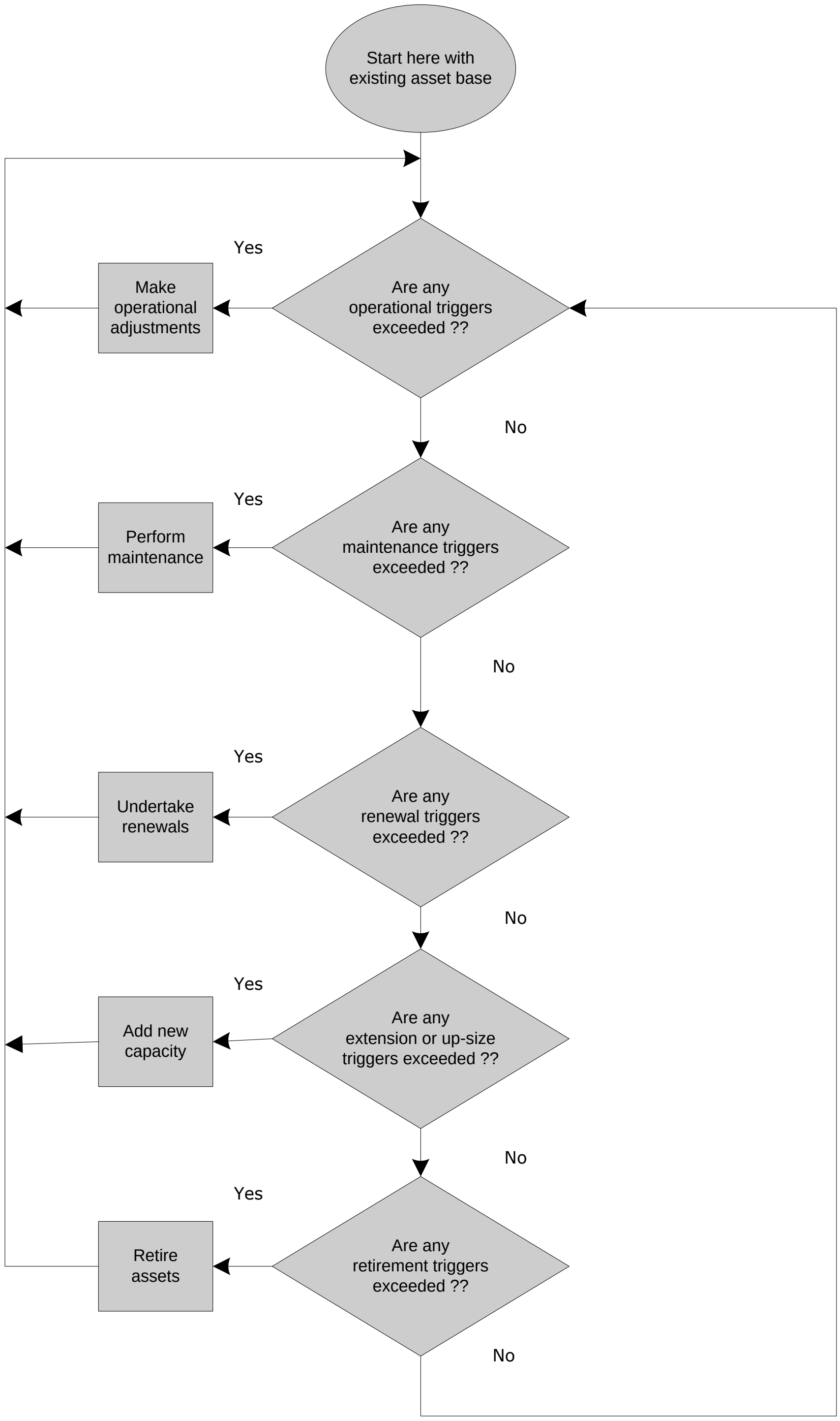


Table 6.2 provides definitions for our key life cycle activities.

Table 6.2 Definition of key life cycle activities

Information Disclosure categories	Activity	Detailed definition
Routine and corrective maintenance and inspection	Operations	Involves altering the design operating parameters of an asset such as closing a switch or altering a voltage setting. Does not involve any physical change to the asset—simply a change to the assets configuration that it was designed for.
	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 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 reduce 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 they become too small. The most typical criteria for renewal will be when the capitalised cost of operations and maintenance exceed the cost of renewal. A key issue with renewal is technological advances that generally make it impossible to replace assets such as SCADA with equivalent functionality.
	Upgrading	Generally involves replacing a non-consumable item like a conductor, bus bar, or transformer with a similar item of greater capacity, but which does not increase the network footprint
Capex	Extensions	Involves building a new asset where none previously existed because a location trigger in 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 will 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 will be when an asset is no longer required, creates an unacceptable risk exposure or when its costs exceed its revenue.

6.3.1 Operating the assets

As shown in Table 6.2, operations do not involve making physical changes to the network. Operations role is to configure switching (or connectivity) and to let the electricity flow from the GXPs to consumers' premises. We operate a dedicated control room to intervene when a trigger point is exceeded and carry out routine switching operations.

Trigger points are operational activities and generally include the activities set out in Table 6.3.

Table 6.3 Typical responses to operational triggers

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	Reactive
	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	Reactive
	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 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 6.4 outlines the key operational triggers for each class of our assets.

Table 6.4 Operational triggers

Asset category	Voltage trigger	Demand trigger	Temperature trigger[24]
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 OLTC to react.	Load exceeds guidelines in IEC 354. Security guideline breached. Consumer complaint.	Top oil temperature exceeds manufacturers' recommendations. Core hot-spot 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.

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

6.3.2 Maintaining the assets and systemic failure identification

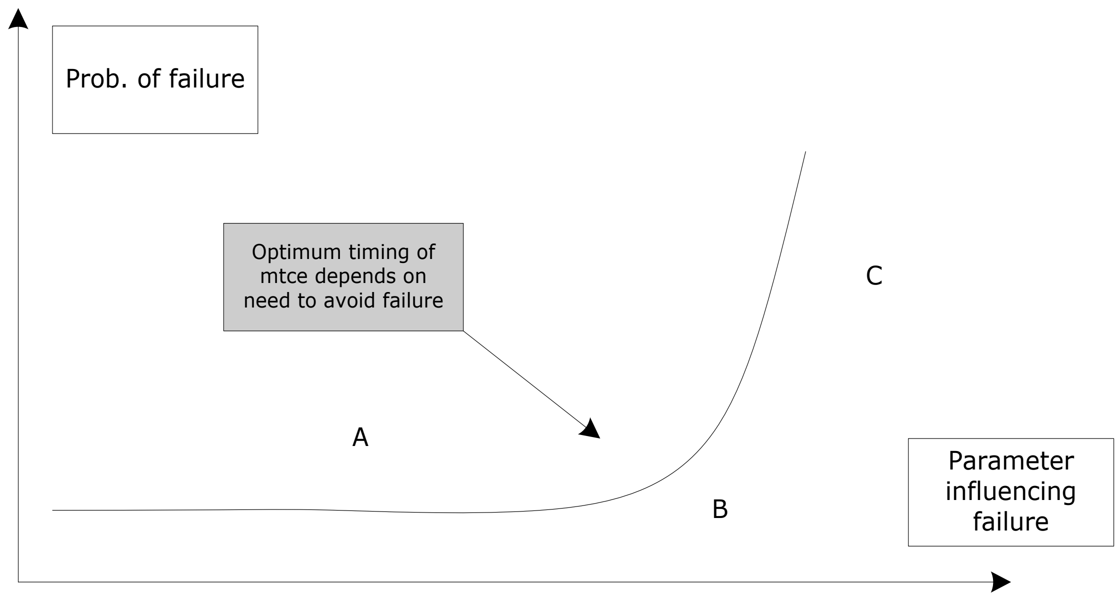
Asset maintenance includes repair or replacement of faulty or deteriorating components and regular inspection and condition monitoring. Condition assessment provides for the detection and recording of gradual deterioration of components (as well as any systemic or type faults) and an opportunity for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

Information gathered from inspections is analysed and corrective actioned 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 may be revealed.

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

Examples of the way in which 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. Continued operation of such components will eventually lead to failure as indicated in Figure 6.2[25].

Figure 6.2 Component failure



[25] Please note that the horizontal axis in Figure 6.2 can be but is not restricted to time.

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 to components due to fault current or over-voltage events
- ambient temperature
- previous maintenance history
- the presence of contaminants.

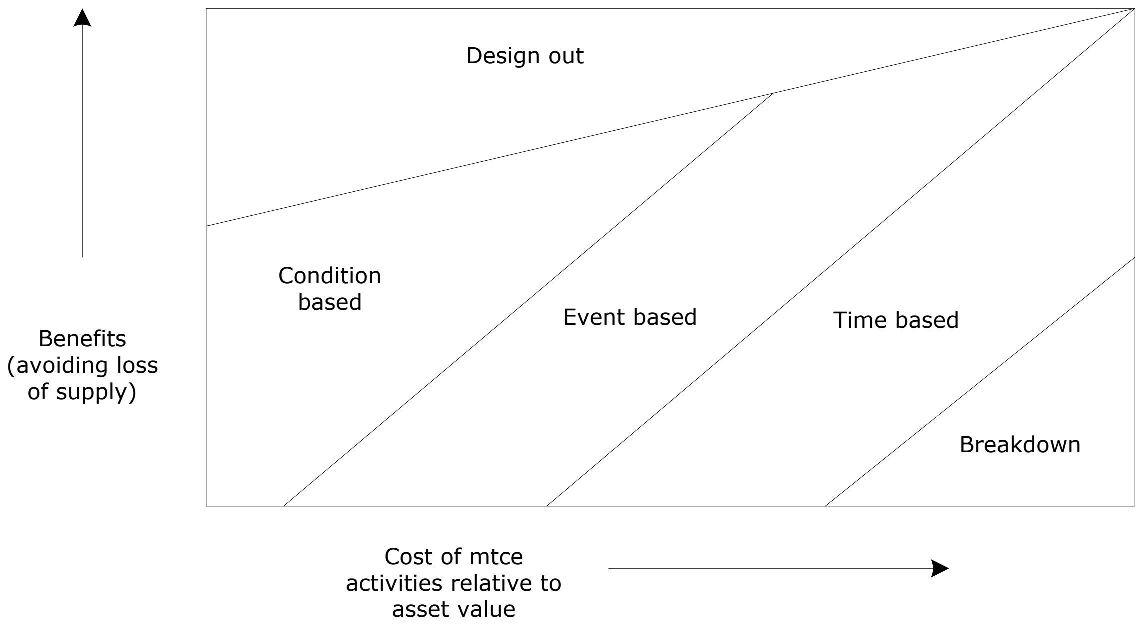
We determine when to perform maintenance based on the need to avoid failure. For example, the need to avoid failure of a 15 kVA transformer supplying a single consumer is low and might be operated out to point C. A 33/11 kV substation transformer may only be operated to point B due to a higher need to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

The trade-off with avoiding failure is the increased cost of labour and consumables over the assets 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 then protecting components while the component remains 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. Assets which have a safety risk associated with them and supply large consumers or large numbers of consumers are extensively condition monitored. Assets supplying only a few consumers and which do not have particular safety risks associated with them, such as a 15 kVA transformer, are more likely to be run to failure.

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

Figure 6.3 Maintenance strategy map



Our map indicates that where the benefits are low, principally there is little need to avoid LOS, and where the costs of maintenance are relatively high, it is appropriate that an asset be run to failure. As the value of an asset and the need to avoid LOS both increase, 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.

It should be noted that this map does not address the question of maintaining the safe condition of assets, such as ground mounted LV distribution boxes, which could be run to failure if it were not for the risk to public safety.

As mentioned above, condition assessment requires regular and routine maintenance inspections and testing of assets. This necessary intervention may, in some cases, have an adverse effect on immediate operational efficiency due to the need to have outages to inspect and test the equipment. However, not undertaking these condition inspections and tests may result in increased safety risk, and a greater loss of efficiency due to consequential failure of equipment and an extended outage. The timing and frequency of the maintenance must be chosen to balance the risks and the effects of the outages.

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

Table 6.5 Maintenance triggers

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 • 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

Asset category	Components	Maintenance trigger
		• 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 • 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

Asset category	Components	Maintenance trigger
	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 • 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 and 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 correctly • Protection not operating correctly • Cyclometers not operating

Asset category	Components	Maintenance trigger
		• Significant partial discharge detected in switchgear • Thermographic evidence of unusual heating of components and/or connections
	Station batteries	• Battery charger not operating correctly (float level) • Battery cell voltages not to spec • Loose connections
	Instrumentation	• Protection relays not maintaining correct settings • Meters not reading • Trip flags not activated • Alarms not operating correctly • Warning flags/lamps 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

The frequency and nature of the response to each of the above triggers are detailed 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 at page 178 and section 6.9.2—Maintenance work plans at page 179.

Typical maintenance policy responses to these trigger points are described in Table 6.6.

Table 6.6 Typical responses to maintenance triggers

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 annual inspection
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by annual 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 test
	Excessive moisture in breather	Filter oil	Condition as revealed by monthly inspection
	Weighted number of through faults	Filter oil, possibly de-tank and refurbish	Event driven
	General condition of external components	Repair or replace as required	Condition as revealed by monthly inspection
	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
	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-yearly 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

Asset class	Trigger	Response to trigger	Approach
	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 where fitted	Make minor repairs unless renewal is required	Condition as revealed 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	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	Replace	Breakdown or condition as revealed by three-yearly 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 six-monthly inspection, or routine detailed condition assessment
	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	Ten-yearly inspection
	Cracked or broken insulator	Replace as required	Breakdown unless revealed by ten yearly inspection
	Splaying or broken conductor	Repair conductor unless renewal is required	Breakdown unless revealed by ten yearly inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection

Asset class	Trigger	Response to trigger	Approach
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

6.4 Renewing assets

We classify work as renewal if there is no change (usually an increase) in functionality i.e. the output of any asset doesn't change.

A key criterion for renewing an asset is when the capitalised operations and maintenance costs exceed the renewal cost, and this can occur in a number of ways.

- Operating costs become excessive—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 insulating paper reach end of life or as the seals and gaskets perish.
- Maintenance costs of new equipment are significantly less than older existing assets—for example, 'maintenance free for life' vacuum and SF_6 insulated MV circuit breakers compared with 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 of new technologies for assets like SCADA decrease by several fold.

6.4.1 Refurbishment

Refurbishment involves the replacement of individual components. It is done to extend the life of the 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 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% x 10 years
+ 70% x 70% x 10 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 which indicates that Capex will need to increase in future years.

Photograph 6.1 Replacing poles

6.4.2 Renewal triggers

Table 6.7 lists the renewal triggers for key asset classes.

Table 6.7 Renewal triggers

Asset category	Components	Renewal trigger
LV lines and cables	Poles, arms, stays, and bolts	Condition based replacement
LV lines and cables	Pins, insulators, and binders	Condition based replacement
LV lines and cables	Conductor	Condition based replacement
LV lines and cables	LV distribution/link boxes	Condition based replacement
Distribution substations	Poles, arms, and bolts	Condition based replacement
Distribution substations	Enclosures	Condition based replacement
Distribution substations	Transformer	Condition based replacement
Distribution substations	Switches and fuses	Condition based replacement
Distribution substations	Cable terminations, joints	Condition based replacement
Distribution substations	Ringmain switches, and so on	Condition based replacement
Distribution substations	Reclosers, sectionalisers	Condition based replacement Controller batteries by age or condition, whichever is sooner
Distribution substations	Regulators	Condition based replacement or maintenance costs exceed replacement Controller batteries by age or condition, whichever is sooner
Distribution substations	Poles, arms, stays, and bolts	Condition based replacement
Distribution substations	Pins, insulators, and binders	Condition based replacement
Distribution substations	Conductor	Condition based replacement
Distribution substations	Cable terminations, potheads, joints	Condition or age based replacement
Zone substations	Fences and enclosures	Condition based replacement or maintenance costs exceed replacement
Zone substations	Buildings	Maintenance costs exceed replacement
Zone substations	Bus work and conductors	Condition based replacement or maintenance costs exceed replacement
Zone substations	33 kV switchgear	Condition based replacement or maintenance costs exceed replacement
Zone substations	Transformer	Condition based replacement or maintenance costs exceed replacement
Zone substations	11 kV switchgear	Condition based replacement or maintenance costs exceed replacement
Zone substations	Cable terminations, cable boxes, joints	Condition or age based replacement
Zone substations	Batteries and chargers	Age or condition, whichever is sooner
Zone substations	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
Sub-transmission lines and cables	Pins, insulators, and binders	Age and condition based replacement
Sub-transmission lines and cables	Conductor	Age and condition based replacement
Sub-transmission lines and cables	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	Age and condition based replacement
Our equipment within GXP		Condition based replacement or maintenance costs exceed replacement or equipment obsolete

Our broad policies for renewing classes of assets are when; an asset is likely to create an operational or public safety hazard, the capitalised operations and maintenance costs exceed the likely renewal costs, finally, continued maintenance is unlikely to result in the required service levels.

6.5 Up-sizing or extending assets

If any of the capacity triggers are exceeded, we will consider either up-sizing or extending our network. These two modes of investment are, however, quite different as described in Table 6.8.

Table 6.8 Distinguishing between up-sizing and extension

Characteristic	Up-Sizing	Extension
Location	Within or close to existing network footprint (within a span or so).	Outside of existing network footprint.
Load	Can involve supply to a new connection within the network footprint or increasing the capacity to an existing connection.	Almost always involves supply to a new connection.
Upstream reinforcement	Generally forms the focus of up–sizing.	May not be required unless upstream capacity is constrained.
Visible presence	Generally invisible.	Obviously visible.
Quadrant in Figure 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— Situation analysis.	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.

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

Given the fairly simple nature of our network, standardised designs are generally adopted for all asset classes with minor site-specific alterations. These designs represent current standards, industry guidelines, and manufacturers' recommendations.

6.5.2 Building new assets

Availability of internal staff dictates if external contractors are used to up-size or extend assets. As part of the building and commissioning process, the information records will be 'as-built' and all testing documented.

6.6 Enhancing reliability

As described in section 4.5.1—How we take account of consumer service level preferences, at page 103, consumers have voiced a preference to receive about the same reliability in return for paying about the same line charges. Accordingly, it is acknowledged that there is no mandate to improve reliability just because it can be improved. However, there is mandate to maintain supply.

There are many factors that will lead to a decline in reliability over time, for example:

- tree re-growth
- declining asset condition especially in coastal marine areas
- extensions to the network that increase its exposure to trees and weather
- increased consumer numbers that grow the lost consumer-minutes for a given fault
- installation of requested asset alterations that increase risk of poorer reliability

- predicted increases in frequency and magnitude of extreme weather conditions due to climate change that would increase the risk of poorer reliability.

Our reliability enhancement program uses an approach that embodies the following steps:

- identifying the consumer-minutes lost for each asset by cause
- identifying the scope and likely cost of reducing those lost consumer-minutes
- estimating the likely reduction in lost consumer-minutes if the work scope was to be implemented
- calculating the cost per consumer-minute of each enhancement opportunity
- prioritising the enhancement opportunities from lowest cost to highest.

6.7 Converting overhead to underground

Conversion of overhead lines to underground cable is also an activity that doesn't fit neatly within the asset life cycle. Conversions tend to be driven more by aesthetics rather than asset-related reasons. As such, conversions tend to rely on other utilities cost sharing. Photograph 6.2 shows the impact of undergrounding network assets.

Photograph 6.2 Undergrounding infrastructure at Domain Road, Temuka

However, in certain circumstances or geographic locations, conversion from overhead to underground may limit or eliminate the risk of network damage and outages from extreme weather events such as wind and snow storms. Where renewal or up-sizing of existing overhead assets is called for, due to activation of the appropriate triggers, placing the new assets underground may be the best engineering and/or economic solution. Similarly, if renewal or up-sizing of existing outdoor switchgear in zone substation is required, then replacement of the existing outdoor switchyards with indoor switchgear and switch rooms may be preferred.

In built up areas, public safety risk reduction or elimination may influence the decision on whether to renew an existing overhead line or replace it with underground cable. Difficulties of access for maintenance due to location and proximity to private or public premises may encourage not only relocating the overhead line but undergrounding it as well. For example, within the Timaru City area there are a number of 11 kV and 33 kV overhead lines that cross built up areas or follow back boundaries in built up areas. Consideration may be given to relocating and undergrounding these lines for reasons of safety and maintenance access before their condition or age indicates that they need renewal or upgrading.

We apply the engineering definition of risk as the product of the probability of the event and the consequences of that event (i.e. risk = probability of the event x consequences of the event). Risk in this context is usually measured in dollars for the convenience of comparing the risks of competing options. Further discussion of this topic in the AMP will be undertaken in section 7.4—Risk management planning for network assets.

6.8 Retiring assets

Retiring assets generally involves doing most, if not all, of the following activities:

- de-energising the asset
- physically disconnecting from other live assets
- curtailing the asset's revenue stream
- removing the asset from the ODV
- the physical removal of the asset from location or abandoning in-situ (typically for underground cables)
- disposal 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 an unacceptable risk exposure because its inherent risks have increased over time, or because emerging trends of safe exposure levels are declining[26].
- Better options exist to create similar outcomes[27] and there are no suitable opportunities for re-deployment.
- An asset has been upgraded and no suitable opportunities exist for re-deployment.

[26] Assets retired for safety reasons are not to be re-deployed or sold for re-use.
[27] For example, replacing lubricated 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 when their condition is such that corrective action is required.

We are developing objective defect criteria for condition based assessments. It is essential that careful consideration is given to the selection of asset defect criteria 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 and they are kept in service until such time as their continued maintenance is uneconomic or until they pose a safety or reliability risk.

Periodic inspections, patrols, servicing, and test work is undertaken to ensure that defects or emerging risks are identified so that corrective work can be undertaken where required. Servicing can also involve minor component replacements (e.g. seals, bushings, and so on.), but does not involve any significant repairs.

The course of action taken to remedy defects is normally determined by the most economic course of action, provided that this does not jeopardise safety or the quality of supply.

Fault repairs are carried out directly following a fault-induced outage when restoring service. This work may or may not involve permanent repair of the faulted asset, and the objective is to restore service as quickly as possible by the most economical method. Further maintenance intervention may be necessary later to make the repairs permanent. Such intervention may require a planned outage.

Maintenance requirements are also influenced by network development projects that lead to the decommissioning of assets, which would otherwise require significant repairs and/or replacement. This is particularly relevant during high network demand growth where existing assets are unable to reach their expected life because they are replaced with new assets to increase capacity.

Maintenance strategies and programs are regularly reviewed 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 from within our financial and asset management systems. This allows for purchase orders to be issued through the year to cover the maintenance work undertaken by our contractors. The team uses these jobs and purchase orders to provide strategic control of the 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.

Table 6.9 The three dimensions of control and associated jobs

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

There are also specific jobs included in the annual set. This is for 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 for routine visits for scheduled testing, inspection, cleaning, maintenance, and minor repairs. Any defects discovered requiring urgent major repairs are attended to in special visits.

Check sheets and reports from these routine and subsequent visits are filed for future reference and analysis.

Corrective maintenance or refurbishments are triggered by inspections which reveal that the condition of the asset is below standard.

Scheduled work is included in Table 6.10.

Table 6.10 Scheduled work

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	Six monthly 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 supplier's recommendation, our experience, and local conditions.
All substations (including single-pole mounted equipment)	Routine checks in association with their earth tests.
System-wide assets	Periodic tests (such as partial discharge of circuit breakers and cables, thermographic checks of structure mounted assets, and oil sample tests for transformers).

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 or inspections reveal the need for immediate or more detailed maintenance, non-routine maintenance is scheduled. This may include on site intervention or removal to the contractor's workshop. Usually maintenance is undertaken on site if at all possible. Where appropriate, routine maintenance may also be undertaken earlier than scheduled while the asset is out of service for urgent work, and the date of the next routine maintenance rescheduled.

6.9.2.2 *Overhead lines and associated pole mounted assets*

NETcon undertakes overhead line patrols, pole inspections, and line maintenance of our 33 kV, 11 kV, and LV lines.

Photograph 6.3 NETcon performing maintenance on overhead lines

These line inspection and maintenance works are directed by us, on a job-by-job basis, with programming guided by age and condition of the 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 11 kV sub-transmission cables interconnecting the TIM GXP and GRM, NST, and HNT substations have been undertaken every two years, beginning in 2006.

The maps are compared with previous maps to provide valuable asset condition information, particularly the state of the 11 kV cable joints.

Two new 11 kV sub-transmission cables[28] from TIM to NST were PD mapped in 2012. These cables will also be retested in 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

[28] These cables are 33 kV rated for possible future 33 kV GXP.

generally undertaken biennially with more frequent tests for assets that have exhibited partial discharge levels.

Depending on the nature of these partial discharge levels, these 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 the switchgear taken out of service, inspected, and maintained as necessary.

6.9.2.5 Thermographic inspections

Thermographic inspections for hotspots on outdoor or exposed insulators and fittings of outdoor installations have been undertaken on a small scale for several years. The intention is to increase the frequency and extent of these inspections.

6.9.2.6 Services provided by NETcon for our maintenance programme

Table 6.11 lists the type of maintenance provided by NETcon.

Table 6.11 Type of maintenance provided by NETcon

Maintenance type	Description
Routine condition assessment	Zone substation and electrical support structures: monthly during sub checks. Dist. subs and RMUs: buildings, kiosks, padmounts, and enclosures—5/15 year cycles*, as part of off-line (full) maintenance.
Urgent reactive maintenance	Zone substation and electrical support structures—immediate. Dist. sub buildings, kiosks, padmounts and enclosures—immediate.
Planned routine maintenance	Zone substation and electrical support structures—five-yearly cycle. Dist. subs and RMUs: buildings, kiosks, padmounts and enclosures—5/15 year cycles.*

**(Note: RMUs have a five-yearly cycle, until condition assessment of all RMUs is completed when the period will be reviewed; the rest of the dist. sub assets have a 15 year cycle. Note that many RMUs have not been maintained for more than 20 to 30 years and, consequently, their present condition is unknown. This poses an unacceptable risk.)*

6.9.3 Defect identification processes

Our maintenance is undertaken by contractors (mainly NETcon) who carry out regular scheduled maintenance inspections to determine the condition of the network and immediately correct any urgent defects. Condition assessment reports are submitted to us and subsequent reactive repair and maintenance work is scheduled.

Urgent work is undertaken immediately after notifying our control room and receiving appropriate permits, operating instructions, and clearances.

Routine maintenance visits are scheduled to substations and other assets based on manufacturer's recommendations, best industry practice, and field experience for the assets concerned. The contractor submits reports to us with a description of the work done and any other matters requiring attention. These other matters may result in a reactive order for repairs or initiate special condition assessments, depending on the nature of the matter requiring attention.

Zone substations are inspected monthly, while ground mounted distribution substations are inspected every year.

6.9.3.1 Special condition assessment projects

Special condition assessment programmes are tailored to specific and present needs. For example, we conduct overhead line and pole inspections up to 48 weeks of the year.

This collected data is then analysed by our engineers, with assistance from NETcon maintenance planners, who then instigate planned and coordinated maintenance actions to correct deterioration and defects. The actions may be organised according to geographical area or particular type of defect correction in order to optimise the maintenance resources. Actions involving many boxes may be grouped into a Capex project.

Any urgent and safety related conditions found during the inspection of each distribution box are fixed immediately by the contractor while on site or referred to us for immediate reactive attention.

A special one-off set of PD mapping of selected main 11 kV cables in the Timaru CBD was conducted in 2011. This was initiated in response to several cable joint failures in the CBD over the previous four years. The cables selected for this PD mapping have several joints per section or have at least one joint of the 1987 era that appears to be prone to failure. Replacement of some of these joints or even whole cable sections may follow once analysis of the results has been completed and the risks and costs have been studied; or we may wait for them to fail and use the data previously collected to more quickly locate the faulty joint for repair.

We plan to extend this type of special detailed condition assessment to other selected HV network plant.

6.9.4 Serious defect rectification process

When a serious defect in plant or equipment is discovered, NETcon is empowered to take immediate action to correct the defect, or make the asset safe, if the defect constitutes an immediate:

- 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 any network access or permissions required before action can be taken, operations are notified of the defect as soon as it is discovered or immediately after the corrective action.

Minor defects may also be dealt with directly by the contractor.

Defects outside of the above risk to immediate safety or the minor maintenance criteria are referred by the contractor to us for a decision. This decision would include either:

- issue of a reactive maintenance order
- scheduling for subsequent routine maintenance visits
- or initiation of a special project whose nature would depend on the type, size, and seriousness of the defect.

6.9.5 Routine maintenance system

Table 6.2 summarises our routine maintenance system.

Table 6.12 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, and otherwise to supplier's recommendations
Ground mounted distribution substations and switches, 200 kVA +	Twice yearly inspection, MDI reading, minor cleaning/maintenance	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	Six 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, sectionalisers)	Inspection and earth test. Minor in-situ maintenance	Annually
Pole mounted enclosed HV & MV switches (recloser, sectionalisers)	Full maintenance	Five 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	Inspect and test capacitance, check	Five-yearly or more

Asset class	Routine maintenance type	Frequency
regulation type)	fuses, and maintain associated assets	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	Ten-yearly, with scheduling based upon age and condition

NETcon undertakes a close inspection of all new equipment and makes any necessary additions or modifications to the protective coatings and water sealing to protect the asset. This is to reduce ongoing maintenance and extend the life of assets.

6.10 Maintenance plans for the next 12 months

This section discusses our maintenance plans and presents our maintenance expenditure projections.

For information on how our maintenance plans take our service level targets into account please refer to section 4.4.5 Ten-year reliability targets on page 98.

6.10.1 Sub–transmission lines and cables

The 2015/16 Opex budget for annual expenditure on sub-transmission lines and cables maintenance is $51,556.

The fourteen 33 kV sub-transmission lines and cables are the highest priority

The 33 kV sub-transmission lines have the largest impact on network reliability should the lines become unavailable. Sub-transmission lines are built to the highest standard of resilience and in the cases of Clandeboye and PAR, they have duplicate circuits to afford supply security, the former through customer contracts. The remaining lines are single 33 kV circuits.

The four 11 kV sub-transmission cables from TIM GXP to Timaru CBD zone substations were augmented in 2011/12 by two new 33 kV cables that are operated at 11 kV between TIM 11 kV GXP and the new NST substation. Should a 33 kV GXP be introduced at TIM GXP (presently 11 kV) in the future (subject to further planning), these two cables (and others planned for feeds to Washdyke) would 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 initially being run at 33 kV with both circuits paralleled. Since it was commissioned in 2014, this new line has been added to the sub-transmission lines and cables maintenance programme.

The transmission lines built in the last 10 to 12 years will be due for inspection and maintenance in their 20th year of service unless their condition suggests this needs to be sooner. This is summarised in Table 6.13.

Table 6.13 Sub-transmission line inspection priority

Location of line	Year of construction	Maintenance 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

6.10.2 Zone substations

The 2015/16 Opex budget for annual expenditure on zone substation maintenance is $493,675.

All zone substation assets are inspected and serviced on a six monthly inspection cycle

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 occur where a feeder fault operates a substation circuit breaker, requiring an operator to attend to review and reset flags before commencing restoration procedures.

We are continuing to develop better standards based on approaches adopted from Transpower maintenance contracts.

Regular zone substation inspections also include buildings and other assets such as well fire protection and security systems. Periodic maintenance of the grounds includes lawn mowing, pruning, weed control, and clearing of drains.

All power transformers have a regular monthly in-service visual inspection and a biannual minor maintenance service

The biannual service encompasses visual inspection, routine diagnostic tests, operational checks, and minor work. In general, maintenance work on the 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 of the tap changers based on manufacturers' recommended number of operations.

Power transformer faults should be diagnosed early enough to remove the unit from service before transformer failure occurs. Full oil refurbishment is initially carried out about 25 years after installation and thereafter approximately every 10 years. 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 of generally between 10 and 15 years, depending on site conditions. It is planned to paint one unit per year over the next 10 years at an average cost of $5,000 per transformer.

Circuit breakers have regular in-service inspections and are subjected to minor and major maintenance routines

Maintenance on oil circuit breakers should be carried out annually and after the oil circuit breaker 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 servicing varies for each type, make and model of circuit breaker, and costs per breaker vary significantly. Older circuit breakers will be routinely trip tested to ensure that clearance times are not compromised.

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 inspected and maintained, and includes the checking, tightening, and cleaning of insulators and connections.

For example, in 2014 during a Transpower outage at Tekapo, 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.

Zone substation earths are tested annually to verify the integrity of the installation

Protection system maintenance is required to affirm that the protection is calibrated within tolerance and will operate when called upon to do so. The introduction of microprocessor protection relays, with internal self-test and monitoring software, has reduced the need for frequent testing of assets. The older electromechanical protection relays, however, still require frequent testing and adjustment.

Substation battery banks are virtually maintenance-free and only require a basic inspection and a charger check, with battery replacement every eight years.

Building repairs are ongoing and include interior and exterior painting, and roofing and wall repairs. Substation buildings and fences are inspected regularly to maintain safety and security standards.

6.10.3 Distribution lines and cables

The 2015/16 combined annual Opex maintenance budget for network lines and cable maintenance (LV, distribution, and sub-transmission) is $3,667,000, split approximately by[29]:

- $374,000 for LV lines and cables
- $3,241,000 for distribution lines and cables
- $52,000 for sub-transmission lines and cables.

The 11 kV distribution lines and cables are typically open ringed in the city areas

To afford supply security for the densely populated areas, the 11 kV distribution lines and cables are typically open ringed in the city areas, and arranged as single spur lines in the rural areas. Increasingly, in the higher load density rural areas (e.g. irrigation and dairy areas), rural lines are also open ringed to provide alternative supply routes as the opportunity arises and necessary line upgrades allow.

The LV lines and cables also have interconnection in the higher populated urban areas, but typically spur lines in all other areas.

There is a steady amount of work required on network lines and cables. This work will repair known problems, which are reducing reliability and safety margins to below what are considered to be acceptable levels.

[29] These amounts include vegetation management but do not include renewal and upgrade expenditures which are in the Capex budget.

Areas reticulated with predominantly concrete poles from early 1960s to late 1970s have, to date, been maintained only as required

Over the next 10 to 15 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 while hardwood poles have a life of 40 to 60 years. Very few concrete pole replacements are expected due to age.

Hardwood poles are an ongoing maintenance concern, as they will eventually rot below ground level

An age based replacement estimate would indicate that on average, 260 to 330 hardwood poles would need replacing each year. However, due to lines being adequately maintained, the age-based approach is a poor indicator of condition. Accordingly, we use condition to inform the replacement of hardwood poles.

Softwood poles are expected to last between 25 to 65 years

The risk of premature failure of a softwood pole, due to brown rot or structural degradation, may necessitate inspection prior to its 25th birthday and a closer inspection frequency towards end of life. We have, in recent years, discussed and monitored premature failure of softwood poles in conjunction with other networks who have experience similar issues. Due to the poor performance and some premature failures, softwood poles will be closely monitored with a view to ceasing use following a report into their viability.

Beyond the planning horizon, analysis indicates that line maintenance requirements will rise

As an increasing number of hardwood poles need to be replaced, analysis indicates that line maintenance requirements will rise. To offset the effects of this significant increase, some work has been brought forward.

The refurbishment program 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 will be evaluated.

It is estimated that approximately 5 km of conductor will need to be replaced each year at a cost of approximately $250,000 per year over the planning period. This replacement rate is expected to increase in the longer term.

From time to time, network lines are subject to extreme conditions such as floods, snow, earthquakes, major wind storms, and so on, which results in failures. Failure of a pole line is relatively easy to repair as spare poles and other fittings can be drawn from normal stock and repairs completed without undue delay. Conductors are not often badly damaged during serious line failures and the same conductor can usually be reused after repairs. Adequate stocks of conductors and accessories are held for most repairs.

6.10.3.1 Routine patrols and inspections

Overhead lines are patrolled to provide an overview of tree growth

Vegetation control and any repair work are scheduled from the line patrols. Electrical Hazards from Trees Regulations 2003 require line owners to advise tree owners of their responsibilities and provide advice and notification when growth limit and notice limit zones have been encroached. We have a dedicated database to administer tree management and notification processes.

Fault patrols and fault repairs are carried out on an as required basis

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 per year. Where there is an identified condition problem, a more in depth analysis is done and a solution is implemented. This can occur in an area subject to extraordinary winds where a particular line support exhibits early failure and is replaced with a stronger alternative.

Since 1985 areas predominately reticulated with hardwood poles installed between 1955 and 1961 have been inspected every 10 years, and replaced as required. Therefore many of these areas are being inspected for the fourth time. Approximately 10% to 20% of poles are replaced each time. Within the next 10 to 15 years it is expected that the remainder of the original hardwood poles will be replaced with the oldest remaining poles in these areas then being 25 to 30 years old. Crossarms are also renewed during pole replacement.

This 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, with condition assessment and replacement at regular 10 year inspection intervals. The aim of inspection is to identify and document all components that may not be capable of supporting design loads for another 10 years and to comply with clearances in ECP34.

Each timber pole is visually inspected above, as well as below, ground down 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 make a measurement of the remaining healthy heartwood. The diameter of the remaining 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.

A two colour tag system is used to identify suspect poles

A standard Red Tag indicates poles at risk of failure under normal structural loads and requires pole 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 over the next 10 years. Applying a safety factor of two, these 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.

The underground cable network system LV distribution boxes would normally only require inspection every five years and maintenance as required by normal condition assessments

However, as a relatively high level of urgent reactive maintenance actions were necessary during 2009/10, a special condition survey of all distribution boxes was initiated of all for an 18 month period; interruptions in the programme due to pressure of other work had delayed the completion of the programme to early 2013. Once the maintenance follow up has been completed following on from the results of the condition survey, inspections will revert to the five year cycle.

6.10.4 Distribution substations

The 2015/16 annual maintenance budget for distribution substations is $1,004,000 and includes inspection, assessment, and repairs. However, replacement of significant items, such as transformers and RMUs, will be financed from the Capex budget.

Distribution transformers are inspected and earths tested every 10 years to comply with the Electricity Regulations

The distribution substation earth testing is carried out within a specific earth testing programme with other HV earthed assets. Overhead pole mounted transformer servicing or testing is carried out in conjunction with the distribution line inspection and maintenance [30].

A targeted condition assessment project was scheduled in 2010/11 for every five years of in-service of ground mounted distribution substations of 200 kVA or greater. This inspection only project allows for any urgent maintenance to be carried out as required during the course of the project.

[30] This excludes earth testing for distribution substations.

Distribution substations without RMUs are on a 15 year cycle of full offline maintenance

This routine maintenance is separate from the distribution substation in-service condition assessment studies referred to above.

11 kV RMU oil switches, whether alone or incorporated within a distribution substation, are targeted for full offline maintenance every five years. One type of oil switch is being replaced on an ad-hoc basis as time and resources allow. The remaining population is being inspected via partial discharge testing and oil samples to ensure oil moisture and dielectric breakdown components are at acceptable levels and the oil switches remain safe and reliable.

Transformers are replaced if they fail or if they are not expected to last another 10 years

It is more economical to replace distribution transformers in this fashion than to refurbish them on site.

Network failures generally result from lightning strikes, cable termination failures, and car accidents. Faulty transformers can generally be replaced within four to eight hours from the stock of spare transformers held at the Washdyke yard.

Maximum demand indicators fitted to the larger ground mounted transformers indicate that few have been allowed to operate for long periods above the nameplate rating. Therefore, the expected life of the distribution transformer is anticipated to be 55 years.

6.10.5 LV lines and cables

The 2015/16 annual maintenance operations budget is approximately $374,000 for LV lines and cables[31].

6.10.6 SCADA, communications, and ripple plants

The 2015/16 maintenance budget for SCADA, communications, and ripple plants is set at $183,000.

In 2013 the present SCADA system Master Station's hardware platform was replaced due to the asset exceeding its economic life

The hardware replacements were chosen to meet the requirements of future software upgrade needs.

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

[31] These amounts do not include renewal or upgrade expenditures which are in the capital budget.

project. New SACDA will include a whole network view that will support efficiencies in preparation, updating, and operational use of our network switching diagrams.

The integrity of the SCADA hardware and software systems is of the highest importance to the ongoing management and safety of the network. The SCADA system Master Station's control centre is housed in the main office building at Washdyke and is covered by a full 24 hour maintenance contract.

The maintenance programme also includes for the routine replacements of d.c. power supply batteries and chargers and the replacement of minor systems, substation alarms, and security systems that have reached end of life.

A new digital GHz frequency radio system for SCADA system communications is being progressively introduced

As zone substations are added to or upgraded within our network, we are installing communications. These modern substations contain microprocessor based protection and control equipment that use the DNP3 protocol and require modern communications (Refer to chapters 3—Network Assets and 5—Network Development Planning for more details).

The legacy UHF analogue radio system has reached end-of-life determined by asset age, reduced support from manufacturers, and obsolescence of legacy technology that is now replaced by microprocessor controlled technology. The legacy base station and repeater require inspection and servicing on a regular basis. Inspections are, as far as possible, 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 a variety of causes ranging from drift in component settings to lightning strikes and severe weather conditions, such as wind on antennae. The 2013 severe winter conditions highlighted the importance of response to communications faults and maintenance of battery backup systems during periods of loss of mains supply, with the fall back being helicopter access to install supplementary battery support.

Communications equipment has, in general, a shorter life expectancy than heavy electrical assets. Typically electronic equipment reaches technical obsolescence in 5 to 10 years although, generally, the equipment assets can be supported in service for 10 to 15 years. A number of analogue radio systems will require replacement within the next two years.

The ripple injection system is gradually being updated

Old rotary injection installations are being replaced with new solid state injection plant. The new injection plant requires minimum maintenance, and maintenance expenditure for these assets will diminish as the older installations are decommissioned. A breakdown on this replacement program is included in section 5.9—Capability to deliver.

6.10.6.1 Communications and SCADA system equipment room

An independent consultant's report was commissioned in 2009 to advise on the state and recommended upgrade path for the existing Communications and SCADA system equipment room at our Washdyke depot.

The report completed in November 2009 confirmed the need for upgrading SCADA to improve reliability and efficiency of the facility. The report made a number of recommendations covering the many different systems and equipment presently housed in the room.

The consultant estimated the cost for upgrading the room and various equipment and systems to between $150,000 and $205,000, depending upon the options accepted.

Since then, it has been considered advisable to review the whole SCADA Master Station and communications set-up. Significant upgrades to the capabilities of the Master Station were found to be required.

In order to maintain adequate SCADA system reliability, the SCADA Master Station has been upgraded and relocated to a new control room facility within our existing headquarters at Washdyke.

This will also enable the equipment room to be upgraded.

6.10.7 Vegetation management

There is an increasing amount of work 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. In addition, wetter ground conditions seem to increase the risk of trees falling from strong wind gusts.

6.10.7.1 Tree cutting programmes

We conduct an active programme of tree cutting to keep trees away from lines and to clear them, where possible, from the routes of new lines and extensions.

We employ two full-time vegetation officers to manage and coordinate the tree control programme, with the majority of cutting being undertaken by specialist professional tree contractors.

A new vegetation maintenance database has been set up to record and assist with the management of the vegetation control work. This new database tool enables tree maintenance to be correlated with the SAIDI events that are attributed to 'tree causes'. It also allows more accurate budgeting, planning, and management of the 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 lines service but which are not used directly to provide line services. The information disclosure requirements provide a list of non-network assets that are used by us, including a description of use, maintenance, and renewal policies (these are listed in the following sections).

We are developing policies for specific areas of asset management, including policies for vehicle maintenance and replacement, ICT asset renewal, and a property maintenance policy.

6.11.1.1 Motor vehicles

Vehicles are used for a variety of roles depending on the department that uses them. The vehicle fleet includes four wheel drive utility vehicles and station wagons. Photograph 6.4 shows a four wheel drive utility pool vehicle.

At present vehicle maintenance and renewal is managed using a spreadsheet based algorithm that records distance travelled, age of the vehicle, and licensing requirements. We own all vehicles in our fleet. Fleet vehicles are managed by the Compliance and Training Manager. Vehicles are replaced every fourth year on average.

Photograph 6.4 Pool utility vehicle

6.11.1.2 Office buildings

When a building is used to house a network asset, the building is also considered to be a network assets.

Non-network asset buildings include the four buildings used to house our engineers, controllers, and corporate staff, and are all located at the Meadows St. depot, Washdyke, Timaru.

The office buildings occupied by ourselves and our subsidiary NETcon are managed by the Corporate Services Manager who conducts building warrant of fitness checks once a month. Safety issues are addressed on notification.

Buildings and facilities are upgraded in line with the strategic requirements of our business to ensure that our facilities are fit for purpose. This includes the upgrade of the NETcon building in 2014/15.

6.11.1.3 Information systems

For a description of ICT systems specific to asset management please refer to section 2.7.1.1—Information technology for asset management.

We pay annual licensing costs for software packages, including Microsoft products. This often, but not always, includes upgrades, support, and maintenance.

Service level agreements are held for our financial software package Nimbus and with Fujitsu for general ICT requirements.

Day-to-day ICT requirements are supported by our ICT Services Team, which has dedicated personnel for this task.

ICT assets are managed by the ICT 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 upgraded.

At present, information management is a high priority area within our business. Investment in staff, knowledge based consultants, and software is being made to find holistic solutions to business information needs. Spending in this area is expected to reduce once targets for service quality are met.

6.11.1.4 Business equipment

Maintenance and renewal of non ICT related office equipment, including furniture, appliances, and so on is managed by the Compliance and Training Manager. Non–network assets are maintained on a case-by-case basis with the exception of all electrical equipment that is tag and tested on an annual basis.

Non-network assets over $500 are approved by department managers and/or the Corporate Services Manager. This process will be formalised with the introduction of the Capex Policy.

6.12 Maintenance (Opex) budget projections

Table 6.14 at page 201 lists the projected maintenance expenditure by asset class for the period 2015/16 in *nominal* (non-adjusted) dollars. Nominal dollars are used in this case to highlight that we are reducing Opex in real terms by an amount equivalent to inflation each year; that is Opex is constant in nominal terms till at least 2022/23.

The maintenance expenditure projections were calculated under the following assumptions.

- Continued growth in maintenance expenditure over the period due to increasing condition assessment activity revealing in detail the extent of urgent repair requirements and more adequate levels of routine maintenance.
- Introduction of centralised control in 2009 with faults work contracted out to NETcon with consequential addition of an estimated $1 million to Opex annual budget under distribution line 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 network maintenance prior to 2008.

- Reduction in maintenance required overall as new lower maintenance assets are introduced into the network over the period as the result of renewals and upgrades.
- Limitations of the NETcon resource to undertake both our maintenance and capital works over the period.
- Limitations imposed by operations on network access (outages and switching) for maintenance intervention.

The above assumptions of reducing growth of maintenance expenditure may not in fact eventuate should the following occur.

- Complexity and size of some of the newer assets increase, requiring higher levels of technical attention during routine and reactive maintenance.
- Numbers of sites and assets increase as the network load and load density increases over the period.
- Higher levels of routine maintenance activity per site as condition assessment requirements increase and techniques for measuring conditions improve.
- Tendency for existing plant that does not immediately require urgent maintenance moves from a low maintenance condition into a higher maintenance condition as the plant approaches the end of its life (e.g. Opex asset refurbishments that do not fall into renewal or upgrade Capex categories).

6.13 Renewal and up-sizing (Capex) budget projections

As discussed previously, there are six categories of network asset lifecycle expenditure, namely:

- operations
- maintenance
- renewal and refurbishment
- up-sizing (or upgrading)
- extensions
- retirement.

All of these are generally budgeted for as operational (Opex) expenses except for renewal and major refurbishment and up-sizing (or upgrading). These latter expenses are covered under the asset replacement and renewal capital expenditure (Capex) budget.

The expenditure planned for asset replacement and renewal is detailed by project with other Capex project expenditure in chapter 5—Network Development Planning, and the totals are summarised with respect to four asset categories in this present section.

Table 6.15 at page 202 summarises the asset replacement and renewal budgets by asset category for the 2015 to 2025 period in real or constant dollars.

6.13.1 Innovations to defer renewal

The need to innovate before we choose large Capex projects to upgrade the network is an integral element of our network planning. Part of this innovation is the decision to install smart meters over the next three years.

For example, we may use smart meters to limit large capital expenditure through control load from ABY and TIM substations, thereby reducing the need for renewal of associated ripple load control relays. Once smart meters have been rolled out, their effectiveness to control load at these and other sites will be evaluated.

Table 6.14 Maintenance expenditure by asset category (nominal dollars)

Asset category	Forecast (in $'000)									
	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25
LV lines and cables	374	374	374	374	374	374	374	374	382	390
Distribution substations	1,004	1,004	1,004	1,004	1,004	1,004	1,004	1,004	1,024	1,044
Distribution lines and cables	3,241	3,241	3,241	3,241	3,241	3,241	3,241	3,241	3,306	3,372
Zone substations	494	494	494	494	494	494	494	494	504	514
Sub-transmission lines and cables	52	52	52	52	52	52	52	52	53	54
SCADA and radio	183	183	183	183	183	183	183	183	187	191
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**	**5,349**	**5,456**	**5,565**

Table 6.15 Asset renewal and refurbishment budgets for 2015 to 25 (constant dollars)

Project category	Forecast (in $'000)									
	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25
Sub-transmission, distribution, and LV lines and cables	2,389	2,623	3,952	2,958	2,600	2,600	2,600	2,600	2,600	2,600
Distribution substations, including transformer, regulators, ring main units, and so on	1,010	830	742	742	742	742	742	680	560	560
Zone substations	1,330	2,150	350	300	150	150	350	200	200	-
SCADA, comms, and load control plants	310	600	150	150	150	150	150	150	150	150
Total asset replacement and renewal projects expenditure	**5,039**	**6,203**	**5,194**	**4,150**	**3,642**	**3,642**	**3,842**	**3,630**	**3,510**	**3,310**

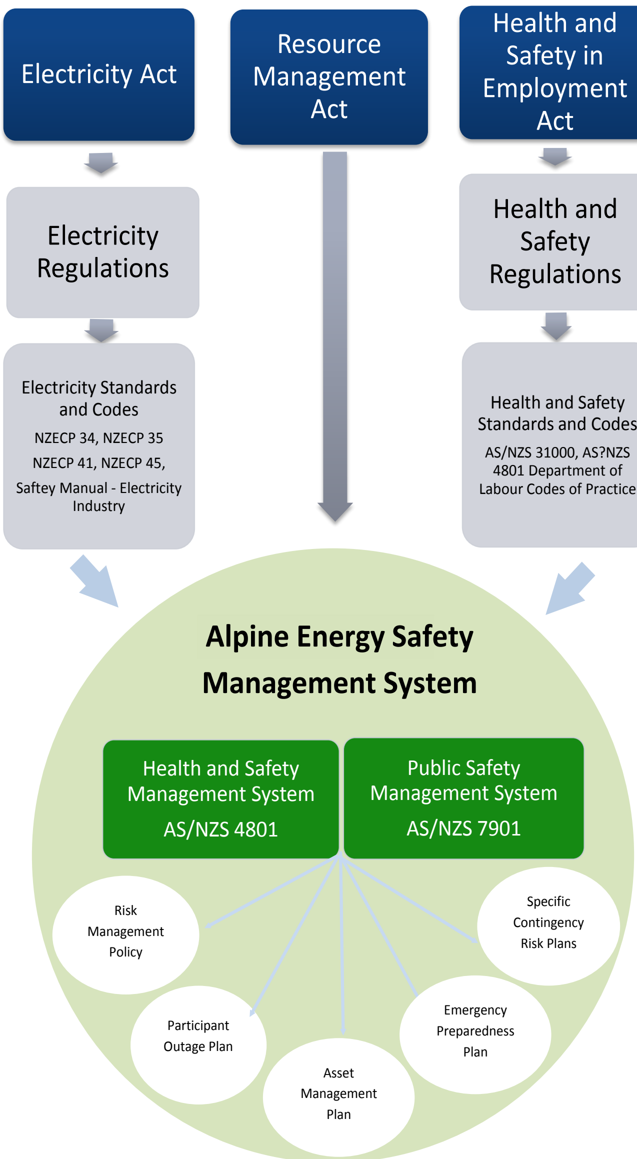
7. Risk Management

7.1 Introduction

This chapter outlines the risk management approach that we apply when managing our network assets and activities. Our approach is based on a 2005 risk assessment. All risk management plans, form our safety management system (SMS), which is described in Figure 7.1.

We are presently developing a comprehensive risk management register to provide better consistency for risk management across all avenues that will strengthen our approach. This will support and standardise our risk assessment and mitigation management. Further information on our policy development can be found at section 5.10.2—Network Development Plan prioritisation process, at page 153.

Figure 7.1 Safety management system framework



7.2 Safety management system

Our integrated safety management system 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:

- NZS7901:2008 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 any member of the public or significant damage to property from network assets and their 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 7901:2009 Electricity and Gas Industries - Safety Management Systems for Public Safety* by an accredited audit body. This has commenced in April 2012, and is repeated annually.

For full details please refer to our Public Safety Management System 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, the consequences of actions by the public can be communicated. This helps to establish awareness in the community of potential hazards and gives a reminder to contact us when perceiving hazards.

For full details please refer to our Public Safety Awareness and Education policy.

Figure 7.2 Promoting safety around electricity through public education

7.2.1.2 Security of ground mounted assets

Our ground mounted assets are protected from public intrusion by way of either placing assets in secure compounds, and/or locking the external body of equipment as is standard practice.

For T1 DB D-boxes, D-boxes and link boxes we are implementing tamper proof uniquely keyed fasteners to replace allen .key closures.

We are presently p[planning a major overhaul of our lock hardware to a single unique keyed lock system.

7.2.2 Health and safety management system

The Health and Safety in Employment Act 1992 requires all companies to have in place an occupational health and safety management system. The purpose of the system is to prevent serious harm to employees, contractors, and general public or significant damage to property arising out of our work activities.

For full details please refer to 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 earthquakes, landslides, tsunami, floods, 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 implemented with peer electricity distribution networks. These agreements were successfully triggered during the Christchurch Earthquakes of September 2010 and February 2011.

For full details please refer to our Emergency Preparedness Plan document.

7.3.1 Business continuity planning

Regular electronic backups of mission critical records that are required for billing of retailers and identification of consumers are performed. The backup copies are securely stored away from site.

We are currently looking to establish a more encompassing business continuity plan that incorporates our SCADA, GIS, and other essential databases.

7.3.2 Emergency Preparedness Plan

Our Emergency Preparedness Plan complies with the requirements of NZS 7901:2008 and AS/NZS 4801:2001 and is regularly renewed 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 process providing them with procedures to follow for emergency events, including:

- civil defence
- general control during emergency events
- 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.

Photograph 7.1 Snow built up on our infrastructure

7.3.3 Emergency communications

Our emphasis on appropriate emergency communication has seen information being provided to stakeholders and the public in a proactive manner. Our communication responsibilities are as follows.

- Chief Executive Officer—media, stakeholders, other EDBs, and Transpower.
- Corporate Services Manager—general public.
- Training and Compliance Manager—Police, Civil Defence, local councils and other local authorities, and large consumers.

Responsibilities for communications are detailed in section 4.2 of the Participant Outage Plan.

7.3.3.1 Telephone video data and network status reports

The public can be kept updated of where outages have occurred and when they have been repaired by logging onto the 'Network status' section of our web page. Telephone video data (TVD) also sends messages to subscribers informing them of outages in areas that the subscriber has indicated information for.

The public can also phone us for information or listen to local radio.

7.3.4 Participant Outage Plan

The Electricity Governance (Security of Supply) Amendment Regulations 2009 requires all specified electricity distributors to prepare and publish a Participant Outage Plan (POP) for audit and approval by the Electricity Authority.

The Participant Outage Plan is required to be written to conform to 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 regional or national electricity supply shortage.

Our most recent Participant Outage Plan has been submitted to the Electricity Authority for audit and approved. A full copy of the current Participant Outage 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 220 kV circuits at TIM GXP, which supply our Temuka 33 kV we have a specific contingency 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 Operation Centre; and a dedicated radio telephone link is installed in TDC's Emergency Operations Centre for direct communication with our control room.

We were a founding member of the South Canterbury Lifelines Group, which has since been amalgamated with the Canterbury Lifelines Utilities Group. The group 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 local Civil Defence Emergency Management plans, and provide technical advice to local authorities and other lifeline utilities as requested.

We participate fully in Civil Defence regional exercises such as 'Pandora' and lessons learnt from these exercises are used to enhance our current emergency response planning.

7.4 Risk management planning for network assets

Risk is defined as effect of uncertainty on objectives. It is often expressed in terms of consequences of an event and the likelihood of occurrence. In the context of electricity distribution, risk is further assessed against a third dimension of controlling of the cost of loss prevention. This recognises the cost penalty and diminishing returns in loss prevention as costs increase.

There is a cost-benefit aspect of risk management of electricity distribution. The optimum point is based on the return gained for the dollar risked. Beyond the optimum it would be inappropriate to spend any more money to reduce the specific risk as this money would be better directed elsewhere, including towards the control of higher 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 so that the risk is within our bounds of acceptable risks.

We assess and treat risk as part of planning and decision making at all levels. To provide consistency and confidence, we will undertake our risk management activities in accordance with our internal standards, which reflect best national and international practice.

We adopt a structured and consistent approach to assess and treat all types of risk, at all levels and for all activities. Our approach to risk management is consistent with the risk management standard *AS/NZS ISO 31000:2009, Risk management—Principles and guidelines*, and our guidelines and procedures, which are based on this standard.

Our aim is for high quality risk management activities to be integrated with all its critical processes so that, before events occur, we are able to recognise and respond to the risks in a consistent and proactive way. Equally, when events do occur, we use systematic processes to learn the lessons from our successes, failures, and near misses. In this way we will drive operational excellence and organisational learning and growth.

Responsibility for managing ours risks rests with the managers, team leaders, and project managers. This includes accountability for ensuring that the necessary controls to modify the risks (i.e. enhancing or reducing) and control assurance activities are in place and are effective at all times.

Assurance of good governance will be achieved through the regular measurement, reporting, and communication of risk management performance.

We will ensure that the resources, delegations, and organisational arrangements to make this possible are in place, and we will establish an assurance program to confirm that this has been achieved.

We have adopted the guidelines for managing risk which are described in *AS/NZS/ISO 31000: 2009 Risk Management – Principles and Guidelines*

This standard prescribes a process for risk management involving the following steps:

- establishing the context
- risk identification
- risk analysis

- risk evaluation
- risk 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 of providing a safe, efficient, reliable, and cost effective distribution system.

This provides a context for identifying the elements that will disrupt the business objectives as well as the severity of the disruption and the probability of its occurrence.

The nature of electricity networks means that they will be exposed to events which threaten the integrity of the components beyond their design capability. The subsequent failures have to be reviewed to determine the impact they have on the consumers' supply and the ability for this disruption to be limited through risk management processes.

A risk management study based on AS/NZ 4360:2004—Risk Management, and the EEA *Guidelines for Security of Supply in NZ Electricity Networks*, was undertaken for sub–transmission and zone substation assets in the 2005/2006 financial year. The findings of this study form the remainder of this chapter.

Since then, the EEA have published a revised *Guide for Security of Supply* August 2013.

As the AS/NZ 4360:2004 standard had already been superseded by *AS/NZS/ISO 31000: 2009 Risk Management—Principles and Guidelines*, a full risk management study will need to be undertaken within the 2014-15 financial year (next 12 months) to ensure compliance with the new standard.

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 program includes routine inspections to ascertain asset condition and regulatory compliance. These policies rank public and environmental safety as a top priority.

7.4.1 Risk identification

Identification of network risk is an iterative process. While this process is well developed, new techniques for predictive condition support and proactive risk management are being developed based on long-life asset management.

7.4.1.1 Environmental risks

We are committed to operating in a manner that supports a sustainable environment.

While there are many environmentally generated events (natural disasters) that threaten to interrupt the operation of the distribution network (e.g. floods, high winds, lightning, snow, earthquake, tidal wave, and fire), there are aspects of the selection and installation of network assets that minimise chlorofluorocarbon gas emissions, oil spills, arc flash exposure, failure of line supports, etc. to mitigate adverse effects to the environment and general public.

Photograph 7.2 Lines and pole down after high wind event

7.4.1.2 External risk

Further external risks 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 clearances from overhead line
- lighting fires adjacent to overhead lines
- moving irrigators under overhead lines
- undermining pole foundations
- collisions with our assets (e.g. car vs. pole)
- illegal access into authorised areas
- leaving electric fence wire or other similar conductive materials where the 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 treatment. A number of dimensions must be satisfied to meet our objectives to manage our assets in a safe, reliable, and cost-effective manner.

We have undertaken a qualitative assessment of risks that we face to determine the ranking of risks that require mitigation. Table 7.1 lists the qualitative measures of likelihood that we use in our risk assessment.

Table 7.1 Measure of risk likelihood

Qualitative measure of likelihood			
Level	**Description**	**Description**	**Frequency**
5	Almost certain	The event is expected to occur in most circumstances	every year
4	Likely	The event will occur in most circumstances	1 in 10
3	Possible	The event will intermittently occur	1 in 50
2	Unlikely	The event will seldom occur	1 in 100
1	Rare	The event will rarely occur	1 in 1000

Table 7.2 provides the qualitative measures of consequence or impact that we use in our risk assessment.

Table 7.2 Measure of risk consequence

Qualitative measures of consequence or impact		
Level	**Descriptor**	**Description**
0.5	Minor	No injuries, supply restored in a day, low financial loss
1.0	Important	First aid treatment, on-site release immediately contained, interruption to supply restored by own workforce in number of days, medium financial loss
1.5	Serious	Medical treatment required, on-site release contained with outside assistance, interruption to supply restored with external line companies in less than four weeks, high financial loss
4	Major	Extensive injuries, loss of production capability, major supply loss restored in number of weeks with overseas crews, off-site release with no detrimental effects, major financial loss
5	Catastrophic	Death, toxic release off-site with detrimental effect, interruption to supply taking many months to restore with external resources, huge financial loss

Table 7.3 combines the qualitative assessment of consequence and likelihood to provide a level of risk matrix.[32]

[32] Our method is based on ISO/IEC 31010.

Table 7.3 Risk matrix

Qualitative risk analysis matrix—level of risk						
Likelihood		Consequences				
		Minor	Important	Serious	Major	Catastrophic
		0.5	1.0	1.5	4	5
5	Almost certain	M	H	H	E	E
4	Likely	M	M	H	V	E
3	Possible	L	M	H	V	V
2	Unlikely	L	M	M	H	V
1	Rare	L	L	L	M	H

Where:

- E = extreme risk; immediate action required.
- V = very high.
- H = high risk; senior management attention needed.
- M = moderate risk; management responsibility must be specified.
- L = low risk; manage by routine procedures.

Risk analysis evaluates the factors affecting the consequences and likelihood of an event and the effectiveness of existing controls and management strategies.

Quantitative analysis is used where specific performance measures are in place, i.e. oil sample testing of zone substation transformers. This technique provides a review of compounds in the oil sample to determine the health and position along its age curve based on known operating history. This allows management of the higher cost (consequence) assets through their service life.

The electrical 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 which connect the 11 kV distribution lines. These 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.

Loss of a high hierarchy asset at the Transpower connection level has a high consequence for disrupting a large number of consumers; however, this is a very low probability event.

Table 7.4 summarises the qualitative results for the level of risk at substations after applying the risk matrix for likelihood and consequences for each listed event.

Please note the levels of risk summarised in Table 7.4 and Table 7.5 at page 216 are based on the then current AS/NZS 4360-2004 guidelines. The risk assessments will be updated once the new ASNZSISO 31000 and its associated ISO/IEC 31010 guidelines have been completed.

Table 7.4 Substation risk level

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 Risk level by asset category

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

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 lowers the likelihood of asset failure.

With growing demand on the network, some substation sites do not have N-1 capacity 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 where these are available.

To date, instances of vandalism have been low. The installation of security alarms, perimeter fences, and locks keep this risk at a low level.

7.4.3.1 In 2014 we commissioned our mobile substation and generation

The mobile substation can generate 1.4 MW but is most efficient generating 1 MW.

Photograph 7.3 Our mobile substation

7.4.3.2 Risks to substation assets

There is an acceptable level of risk from line hardware at substations 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 primary protection fail to operate and clear the faulted zone. The backup protection will isolate a very large area of consumers, having an impact on consumer supply. This protection arrangement does protect other feeders fed from the common bus bar and cannot easily be improved upon without being included within major works.

To prevent the level of risk increasing at the HNT Substation we conduct regular testing of the remaining legacy protection schemes and conduct peer reviews of protection setting alterations. To lower the level of risk, upgrading of the electromechanical relays to microprocessor controller assets at the substation when assets reach end-of-life will reduce co-ordination and discrimination problems.

Procedures for operating at CD1 and CD2 substations need 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 the GRM, HNT, and NST substations due to improper excavation. Recent upgrades provide for the circumstance where the fibre optic 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 substation[33] and PAR substation[34] have reduced the risks from high and medium, respectively, to low. With the exception of the existing PAR substation 11 kV switchboard, the risk has only been lowered from high to medium due to both half busses sharing the same room and there being no arc flash containment or ducting to the exterior of the building. The two new PAR substation 33 kV switch rooms, one for each half bus, do have arc flash containment and ducting to the exterior and so are rated as low risk.

The arc flash protection and containment at GRM and NST substations reduces risk while housing 11 kV busses 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 this sub.

The new RGA T2 11 kV switchboard has arc flash protection and containment rating and is in a separate building from the older T1 11 kV switchboard which does not have arc flash protection or containment.

7.4.3.3 Risk to incoming supply

The highest risk category for substations is the reliability of the incoming supply. Typically this is provided via Transpower. In some cases, this is via a single Transpower feeder, which

[33] Addition of T2 transformer including 33 kV and 11 kV switchgear.
[34] Replacement of both banks with larger transformers and indoor 33 kV switchgear.

results in a required outage to do repairs. Detailed studies are done to determine the cost–benefit for duplicate feeders or alternative generation options to reduce the level of risk.

7.4.3.4 Risk to ripple injection plant

Our ripple injection plants are a critical element in managing controllable load on our network. With the constraints in the transmission network requiring load to be shifted to meet operational transmission constraints, failure of a ripple injection plant creates a high risk of load curtailment during a constraint period as well as a financial penalty of excess transmission charges. The ripple injection plants require critical spares 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 are used that meet the extreme weather conditions. Photograph 7.4 shows snow on network assets on Mt Studholme.

For example, the 11 kV switch room at STU substation has been elevated to prevent flood risk. Transpower will elevate any new works at the substation in the future

Photograph 7.4 Snow on Mt Studholme

Earthquakes pose a significant risk for network interruption and supply re-establishment

The likelihood of an earthquake on our network has been defined as possible. The probability of an Alpine Fault[35] 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 area are seismically restrained. An earthquake from the Alpine Fault could result in some Twizel and Tekapo consumers being 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 transformer upgrades at PAR and RGA substations, in 2012, have reduced the earthquake risk from moderate to low owing to the addition/replacement 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. Accordingly, the risk level is unacceptable.

The NST substation has additional room and facilities to provide a second base for the control room operations and back-up ICT servers in the event of a disaster damaging or destroying the Washdyke offices and depot.

7.4.3.6 Risk to capacity headroom

Growth in South Canterbury is consuming the redundant capacity within the TIM, TMK, STU and BPD GXP's and may reduce security levels at some times during peak periods to N contingency. We are in discussions with Transpower to increase capacity and reduce the risk of supply constraints.

7.4.4 Risk management strategies

The following strategies are used by us to manage risk:

- elimination
- isolation
- minimisation.

In this section we outline how we use our risk management strategies to manage risk to our network assets. How we review our process to assigned risk levels, evaluate new risks, and apply treatments to lower risk for each asset category is discussed below.

[35] The Alpine Fault is a geological fault, specifically a right-lateral strike-slip fault, which runs almost the entire length of New Zealand's South Island. It forms a transform boundary between the Pacific Plate and the Indo-Australian Plate. More information can be found at http://en.wikipedia.org/wiki/Alpine_Fault

Table 7.5 at page 216 summarises the qualitative results for the level of risk for the remaining asset categories after applying the risk matrix for likelihood and consequences for each listed event.

7.4.4.1 Sub–transmission

The 33 kV cables (sub-transmission) on our network are high risk as the cables 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 (i.e. third parties digging them up). Fortunately, 33 kV cables are few in number and the risk treatment is relatively inexpensive, mitigated by providing contractors with plans of cable locations prior to planned excavations and requiring supervised excavation near cables.

Cable strike risk also applies to the TIM 11 kV sub-transmission cables but, with two additional cables recently added, this risk has been reduced. The 11 kV cable feeders supplying the Washdyke industrial area are now the focus of our attention. The reduction of risk as will occur during feeder upgrades (driven by load growth).

The 11 kV cable network has a higher degree of redundancy in urban areas due to feeder cables being installed in a ring configuration. Rural 11 kV distribution cables are typically radial feeders 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 lines 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[36] to our cables by holding stock in critical spares[37]. Further work to fully assess the vulnerabilities of cable on our network is being done in conjunction with the Civil Defence Emergency Management Group (CDEMG) studies on lifeline utility performance during natural disasters and the interdependencies between the utility systems. For further details refer to 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 but 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.

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[36] The higher the cable voltage, the greater the impact on the system reliability and on the restoration of supply, should damage occur.

[37] Stock is generally held for normal repairs rather than natural disasters due to high stock holding costs and availability from suppliers.

Voltage regulators, reclosers, and ring main units have moderate to low risk levels which are catered for within design standards and stock held in critical spares.

7.4.4.4 Low voltage (LV)

LV lines and LV cables are generally low risk. Risk is mitigated through having stock in critical spares and through our asset management practices to ensure quality standards are maintained.

LV distribution boxes are a collection of different box types and configurations. Different box materials carry different risk profiles; the highest risk is ground mounted fibreglass boxes, which can be damaged by vehicles. We keep the level of risk at moderate to low through our programmed condition assessments, regular surveillance to ensure the integrity is maintained, work standards, and design standards.

7.4.4.5 Buildings

The risk of building failures has been addressed through seismic reinforcement projects completed shortly after the Christchurch earthquakes.

7.4.5 Network capacity

Our policy is to provide sufficient capacity to meet consumer demands. Accordingly, we design expansions on our network taking into consideration the projected load growth for the area. All customer initiated upgrades or development work must meet with our capital investment criteria and be funded by the customer.

7.4.6 Operational security

Operational security is the risk of disruption of electricity supply and inadequate network capacity. Capital investment for network security is evaluated based on the:

- estimated cost to consumers of energy not supplied
- probability of an outage occurring and the expected duration of that event.

7.4.6.1 Resource Management Act 1991

The Resource Management Act 1991 is the major legislative driver for us. 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 consents for new work and management systems for environmental and public safety issues for 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 (particularly for transformers). 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 programs include the upkeep of sound enclosures. Although noise complaints are occasionally received and investigated by the local council, no remedial action has been required to date.

7.4.6.3 Electromagnetic fields

Health effects of power frequency electromagnetic fields have commanded international attention in the past. However, no conclusive evidence has emerged that power frequency electromagnetic fields are a danger to human health. Copies of the National Radiation Laboratory booklet on the effects of EMF are made available to concerned consumers.

7.4.7 Risk management improvements

Plans to improve the management of risks on our network will require the qualitative study to be extended with completion of a formal risk register. The register will strengthen our risk management process and drive regular reviews that check present risk performance and whether any new risks have developed, thereby providing continuous process monitoring and risk review.

In accordance with the Health and Safety in Employment Act 1992 and Electricity (safety) Regulations 2010, we have a database that records and manages risks on our network.

8. Asset Management Maturity Assessment

8.1 Introduction

This chapter 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[38], 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 in which 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 their asset management maturity by applying a score of zero to four to each question. We scored ourselves with a maturity level between 1 and 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 them.
- 2—we have a good understanding of the standard, 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 used the latest EEA Guide to the AMMAT[39] (EEA AMMAT guide) to help us identify our level of maturity for each AMMAT question. For each question the EEA AMMAT 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. That is, we round our scores up.

[38] Commerce Commission, Electricity Distribution Information Disclosure Determination 2012, Decision No. NZCC 22, 1 October 2012, clause 2.6.1(5).
[39] Electricity Engineers' Association's Guide to Commerce Commission Asset Management Maturity Assessment Tool, March 2014

Table 8.2 at page 232 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.

8.2.1 Changes to our AMMAT scores from last year

The use of the EEA AMMAT guide to identify our present maturity is a new method we have used and it has meant that we have revised our AMMAT scores from last year. This enhanced understanding of the AMMAT and of our own systems and processes has in some cases meant that we now score ourselves with a lower level of maturity. We believe that by scoring ourselves as accurately as possible we can prioritise actions that will move us towards our target level of maturity for each process or system described in the AMMAT.

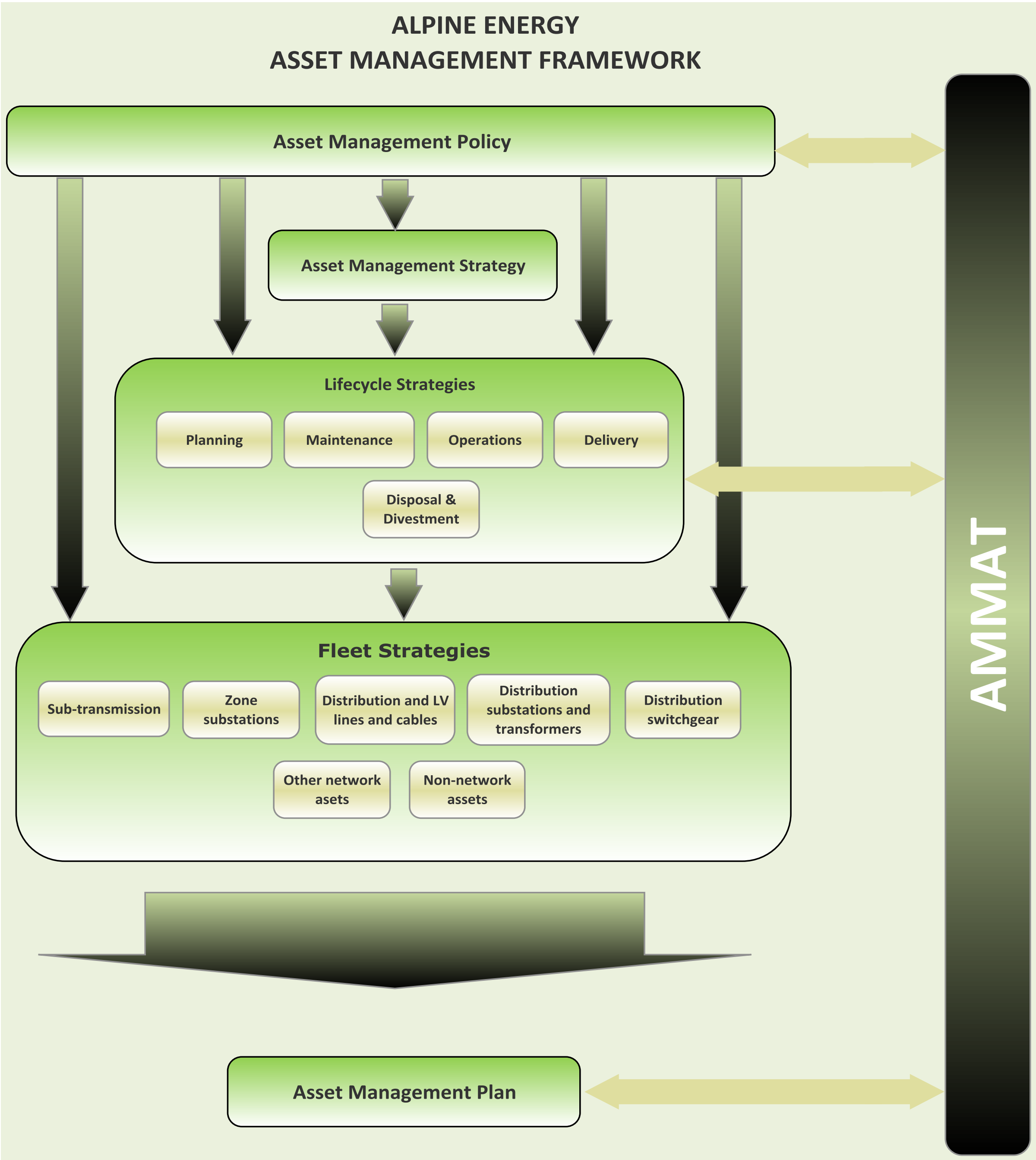
8.3 Continuous improvements to our asset management system

Our AMS is presently not a formal document; instead, it is inherent within the AMP. As part of our AMMAT guided self-assessment, we will create the AMS as an external document.

The AMS will be created with the use of the EEA AMMAT guide, in conjunction with the AMMAT to assess our present level of maturity and also to identify what actions are needed to reach our target maturity. Identified actions are grouped into asset management areas, and prioritised with the NDP (see section 5.10.2-Network Development Plan prioritisation process). The actions required for each asset group will form the group's asset strategy, while the collective group strategies will form the AMS and, ultimately, the AMP.

This process is further described in Figure 8.1.

Figure 8.1 Planned document hierarchy and the AMS



In parallel with this process we are updating our business process maps (BPM) and reviewing our asset management related ICT systems. These are discussed in more detail below.

8.3.1 Business process mapping

During 2014 we commenced Stage 2 of our business process mapping. Through Stage 2 we will review 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 the continuous improvements identified since stage one.

8.3.2 Asset management system's information upgrade

We are currently upgrading, replacing, and securing a number of our information technology systems (ICT) which are integral to our AMS. In August 2011 we engaged Deloitte to carry out a complete review of our ICT needs. The report highlighted that our ICT systems were outdated and that we were inadequately prepared for disaster recovery. We considered the findings of the Delottie's ICT review and determined 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 provide us with the tools that we need to provide better service to our customers.

Our ICT systems are not fully integrated with the exception of GIS with gentrac and the ICP system. This necessitates that individual data is often entered separately into more than one package in order to satisfy the different database and software package requirements for data entry. Ideally all of our systems will be fully integrated and replace existing legacy paper based and spreadsheet based processes where practicable.

Key to upgrading our AMS is the accurate collection and processing of asset data, this is discussed more fully below.

8.3.2.1 Improving asset knowledge quality

Effective asset management as well as any improvements to asset management related ICT systems, can only occur with quality data (for technical description, age, condition, and location of assets).

The field capture of our overhead distribution system has improved the accessibility and quality of the asset data, although gaps remain. Also improved 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 reasonable and practical to place this information on GIS.

Asset condition information also remains a key area for enhancement. Significant progress has been made over recent years with condition assessments being conducted on distribution boxes and distribution transformer installations by our contractor NETcon.

GIS software and application development now allows electronic field data capture to be processed on the move and update records seamlessly. Further developments in moving to new communication mediums between substations will also improve the degree of data which can be accessed and hence how the system is operating in real time, rather than reactively once an event has occurred.

8.3.2.2 GIS upgrade

Our existing GIS is an internally developed (in-house) system which is an integral element of the AMS. At present we are enhancing the capabilities of the GIS system. This enhancement will provide:

- a fit for purpose facility to identify 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 of the 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 New Connections 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 AMS, such as SCADA, ICP and gentrac.

8.3.3 SCADA upgrade

Currently we are undergoing a system upgrade from our existing iFix system to Survalent. The upgrade is required 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 with the new version of iFix. This also includes upgrading the hardware that the systems run on and moving into 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 discussed above in section 8.3—Continuous improvements to our asset management system on page 227.

As our asset management systems and processes mature we will be better able to communicate these in our AMP, leading to improved compliance.

Beyond compliance we are looking to improve the way the AMP communicates key information and achieves its purpose. We plan to make the enhancements to the AMP over three stages, over a three year period. Stage one and two includes the restructure of our AMP with incremental changes being made, including the layout and overall structure of the document; stage three will commence once we have finalised our AMS as described in section 8.3 above.

Table 8.1 shows areas identified in our AMP that can be enhanced.

Table 8.1 Areas in the 2015 AMP identified for further development

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 of efficient, safe and reliable delivery of energy are found throughout the AMP. However the introduction of the NDP (see section 5.10) will make these 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 the EDB's other strategy and policies;	See section 8. (Continuous improvement).
3.14 An overview of asset management documentation, controls and review processes	We are enhancing our review processes, this is discussed in section 8.3 (Continuous improvement).
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, this is discussed in section 8.3 (Continuous improvement).
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. This is consistent with other electricity distribution businesses (EDBs) of our size. However the AMMAT review, see section 8.3 of the 2015 AMP (continuous improvement) 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 8.2 Extract of Schedule 13: Report on asset maturity

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 which 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 which ensures consistency between our policies and strategies around asset management objectives.

Assessment category	Question no.	Question	Current year	User guidance
Asset strategy and delivery (continued)	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, but this draft 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 which 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 which is linked to our asset management practices. We have yet to fully document our risk and control measures.
Documentation, controls, and reviews (continued)	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 makes 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 how it is that this requirement. We are now reviewing our initial BPMs

Assessment category	Question no.	Question	Current year	User guidance
	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 this 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))?	1	We do not currently have the information that is contained within our asset management system externally audited. The system is dated and complex; we have found it difficult, if not impossible, to source an appropriate audit option. We recognise the importance of external audits and intend to include a regular audit process in the scope of our new asset management system.
	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 these.
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.

Assessment category	Question no.	Question	Current year	User guidance
	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)?	2	The roles and responsibilities, selection criteria and review processes for the appointment of members of the asset management team are documented but not reviewed against strategies and objectives.
	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 and gentrack. We will look to improve this score during 2014 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
	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 this.
	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 review this.
	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 this score in the future.

Assessment category	Question no.	Question	Current year	User guidance
	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..
	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 these 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..

Assessment category	Question no.	Question	Current year	User guidance
	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.
	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 complete these.

Appendix A Summary of 11 kV feeders

Table A.1 provides a summary of the 11 kV on our network.

Table A.1 Summary of 11 kV feeders on our network

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD
ABY0111	ABY	2732	Raincliff	87	2348	114	85.74	0.31
ABY0111	ABY	2742	Cave	228	4887	392	207.83	0.78
ABY0111	FLE	F309	Fairlie	332	11570	982	246.97	1.00
BPD1101	BPD	CB2	Ikawai	104	6,585	145	66.14	3.24
BPD1101	BPD	CB3	Waikakahi	80	3,435	105	53.23	1.49
BPD1101	BPD	CB4	Tawai	138	8,590	368	73.30	3.99
BPD1101	BPD	CB5	Ripple Plant	1	-	1	0.01	0.14
STU0111	STU	01	Otaio	188	9,223	311	114.20	5.78
STU0111	STU	02	Glenavy	32	2,348	43	19.43	2.55
STU0111	STU	03	Waimate	89	12,555	1,878	33.30	4.83
STU0111	STU	07	Waihaorunga	154	5,270	225	130.36	1.53
STU0111	STU	08	Mount Studholme	180	14,503	292	89.41	2.54
STU0111	STU	09	Morven	174	8,168	282	101.10	2.59
TIM0111	Grasmere	01	Local Service No. 1				0.02	
TIM0111	Grasmere	02	White Street	6	2,950	364	2.17	1.40
TIM0111	Grasmere	04	Grasmere St/Hunt St - GHA				1.64	6.07
TIM0111	Grasmere	05	Nile Street	6	2,650	572	2.57	1.64
TIM0111	Grasmere	06	Parkview Terrace	4	1,200	9	3.41	1.85
TIM0111	Grasmere	07	Douglas Street	3	1,400	241	1.51	0.52
TIM0111	Grasmere	08	To RMU F11				0.01	6.01
TIM0111	Grasmere	10	Ashbury Park	4	1,950	186	2.85	1.10
TIM0111	Grasmere	12	Selwyn Street	7	3,100	534	2.28	1.65
TIM0111	Grasmere	15	Park Lane	6	2,600	462	2.69	1.67
TIM0111	Grasmere	16	Evans St./North Mole	4	2,650	9	3.67	0.83
TIM0111	Grasmere	17	June Street	4	2,300	272	1.53	1.25
TIM0111	Grasmere	18	Grasmere St./ Victoria St. - GVB				3.11	5.50
TIM0111	Grasmere	20	Hobbs Street	5	2,600	409	2.00	1.49
TIM0111	Grasmere	21	Local Service No.2	1	75	1	0.01	0.00
TIM0111	Hunt	01	Harper Street	2	1,000	233	1.22	0.66
TIM0111	Hunt	02	Wilson Street	5	1,900	325	2.36	1.18
TIM0111	Hunt	03	Grasmere St/Hunt St - GHA				0.02	6.05
TIM0111	Hunt	04	Baker Street	4	1,900	395	2.22	1.22
TIM0111	Hunt	05	Le Cren Street	8	4,550	580	2.33	2.25
TIM0111	Hunt	06	Hunt St/Victoria				1.25	5.00

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD
			St - HVA					
TIM0111	Hunt	07	Church Street - South Side Footway	4	2,600	267	1.58	1.51
TIM0111	Hunt	10	Gibson Street	3	1,200	173	2.27	0.89
TIM0111	Hunt	11	Rhodes Street	6	2,350	590	2.60	1.53
TIM0111	Hunt	12	Grasmere St/Hunt St - GHB				3.56	5.47
TIM0111	Hunt	13	Clifton Terrace	4	1,900	486	1.53	1.42
TIM0111	Hunt	14	Church Street - South Side Roadway	3	2,150	62	1.93	2.02
TIM0111	Hunt	15	Hunt St/Victoria St - HVB				1.25	4.91
TIM0111	Hunt	16	Arthur Street	5	3,400	199	1.37	1.73
TIM0111	North	03	Redruth 1				0.21	0.85
TIM0111	North	04	Rose St	4	2,050	346	1.88	0.87
TIM0111	North	05	Craigie Ave	8	3,500	696	3.55	1.69
TIM0111	North	06	GRM - NST A				0.75	5.53
TIM0111	North	08	Barnard St	5	2,500	157	1.08	1.16
TIM0111	North	09	Port 1	1	500	2	2.04	20.00
TIM0111	North	10	Fraser St	5	2,800	22	2.39	0.95
TIM0111	North	11	Hayes St	6	3,800	76	1.87	1.09
TIM0111	North	12	High St	10	3,325	242	5.27	1.34
TIM0111	North	13	Port 2	3	3,400	13	2.28	2.00
TIM0111	North	16	Victoria St	5	2,400	329	1.68	1.45
TIM0111	North	17	Stafford Street	5	3,900	189	2.19	1.92
TIM0111	North	18	Redruth 2				0.22	1.13
TIM0111	Pareora	CB3	CFM No.1			1	0.34	2.58
TIM0111	Pareora	CB4	St. Andrews	216	8,935	377	129.42	2.27
TIM0111	Pareora	CB5	CFM No. 2				0.34	2.62
TIM0111	Pareora	CB6	Normanby	170	6,500	531	75.57	1.71
TIM0111	Pareora	CB7	Holmestation	166	4,264	280	116.87	1.45
TIM0111	Pleasant Point	01	Waitawa	119	10,103	241	41.36	1.61
TIM0111	Pleasant Point	02	Sutherlands	68	1,303	91	44.20	0.83
TIM0111	Pleasant Point	04	Totara Valley	150	7,960	525	75.22	2.23
TIM0111	Pleasant Point	05	Pleasant Point Township	42	3,020	317	24.35	1.20
TIM0111	Timaru	2682	Ripple Plant No.1				0.10	
TIM0111	Timaru	2692	North Street 1				5.95	5.37
TIM0111	Timaru	2702	Morgans Rd	23	5,760	891	9.33	2.68
TIM0111	Timaru	2712	Mountain View Rd	31	5,940	887	12.04	3.20
TIM0111	Timaru	2732	AEL T1	3	86,700	2	17.85	6.25

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD
TKA0331	BML	M216	Simons Pass	16	410	26	36.69	0.30
TKA0331	GTN	M210	Glentanner	6	410	12	9.09	1.20
TKA0331	HLB	M38	Lilybank 22 kV	8	315	12	38.03	0.30
TKA0331	HLB	M40	Haldon Station 22 kV	30	760	37	77.95	0.70
TKA0331	TEK	M200	Haldon-Lilybank	10	1,875	70	5.66	1.37
TKA0331	TEK	M201	Balmoral	7	1,775	6	6.02	0.31
TKA0331	TEK	M205	Godley	9	525	66	20.73	0.15
TKA0331	TEK	M206	Tekapo Township	21	3,965	287	8.39	2.23
TKA0331	TEK	M207	Local Service	1	3,050	2	0.06	0.30
TKA0331	UHT	M158	Village	5	2,300	14	5.27	1.00
TKA0331	UHT	M159	Village	6	815	69	4.95	0.50
TMK0331	Clandeboye Sub 1	T600	Tie to Milk Powder 2				0.50	0.01
TMK0331	Clandeboye Sub 1	T601	Fire Services	10	8,300		0.44	4.11
TMK0331	Clandeboye Sub 1	T602	Whey Processing	6	6,500		0.15	7.70
TMK0331	Clandeboye Sub 1	T603	Lactose Plant	1	1,000		0.09	2.75
TMK0331	Clandeboye Sub 1	T604	Spare				0.02	0.00
TMK0331	Clandeboye Sub 1	T605	Tie to Milford Clandeboye rd.	72	6,730	206	39.98	0.27
TMK0331	Clandeboye Sub 1	T607	Bus Coupler					7.39
TMK0331	Clandeboye Sub 1	T609	Milk Reception	3	2,500		0.47	0.81
TMK0331	Clandeboye Sub 1	T610	Chilled Water No. 1	4	6,000		0.55	2.74
TMK0331	Clandeboye Sub 1	T611	Effluent Plant	5	6,000		0.49	1.90
TMK0331	Clandeboye Sub 1	T612	Milk Treatment	2	4,000		0.55	1.14
TMK0331	Clandeboye Sub 1	T613	Rolleston Road	1	15	6		3.55
TMK0331	Clandeboye Sub 1	T614	Tie to Power Handling	1	1,500		0.53	1.26
TMK0331	Clandeboye Sub 2	T650	Tie to Milk Powder 1				0.18	1.68
TMK0331	Clandeboye Sub 2	T651	Milk Powder 3	7	19,000		0.25	6.22
TMK0331	Clandeboye Sub 2	T652	Tie to WPC	1	1,500		0.41	1.14
TMK0331	Clandeboye Sub 2	T653	Chilled Water 3	4	3,200		0.32	1.14
TMK0331	Clandeboye	T654	Tie to	4	6,000		1.02	1.58

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD
	Sub 2		Boilerhouse					
TMK0331	Clandeboye Sub 2	T656	Bus Coupler					2.33
TMK0331	Clandeboye Sub 2	T658	Milk Powder 2	6	16,000		0.17	3.55
TMK0331	Clandeboye Sub 2	T659	Tie to Energy Centre 1				0.60	1.09
TMK0331	Clandeboye Sub 2	T660	Refrigeration	4	5,000		0.53	1.98
TMK0331	Clandeboye Sub 2	T661	Laboratory	3	4,500		0.36	1.71
TMK0331	Geraldine	01	Speechly	226	7,098	405	127.11	0.00
TMK0331	Geraldine	02	Geraldine Township	78	9,525	1,355	25.53	0.00
TMK0331	Geraldine	03	Woodbury	297	8,215	669	149.90	0.00
TMK0331	Rangitata	03	Mahan Road	62	5335	85	32.96	2.98
TMK0331	Rangitata	04	Main South Road	53	5605	81	31.30	1.90
TMK0331	Rangitata	11	Belfield	78	5825	110	44.30	2.98
TMK0331	Rangitata	12	Orton	13	1170	15	11.80	2.15
TMK0331	Rangitata	32	Bus Coupler				0.01	5.15
TMK0331	Temuka	01	Temuka West	9	51,675	417	5.16	2.54
TMK0331	Temuka	02	Milford	118	7,330	263	55.47	2.62
TMK0331	Temuka	03	Winchester	210	10,013	571	77.42	3.30
TMK0331	Temuka	07	Rangitata	85	6,750	132	44.08	3.82
TMK0331	Temuka	08	Temuka East	72	13,080	1,771	23.26	5.22
TWZ0331	TVS	Z1	Urban No. 1	22	4,230	625	6.99	1.24
TWZ0331	TVS	Z2	Urban No. 2	29	5,370	644	11.85	1.32
TWZ0331	TVS	Z3	Industrial	1	50	1	0.21	0.00
TWZ0331	TVS	Z4	Twizel Rural	42	2,260	97	37.34	0.37
TWZ0331	TVS	Z9	Local Service	1	3,030	2	0.01	0.00
Total		**135**		**5,576**	**690,200**	**30,647**	**3,255**	**332**

Appendix B Capex 12-month works plan for 2015/16

Table B.2 below provides a list of projects that we will either complete during 2015/16 or start and complete during 2015/16.

Projects are listed in real (constant) dollars and in thousands ($000).

Table B.2 List of projects to be completed and/or started during 2015/16

Works programme project	Budget ('$000)
Various O/H refurbishment & renewal	1208
Waihao Downs feeder	1300
Waihuna feeder & regulator	200
Wains crossing	80
Te Moana Rd refurbishment	189
33 kV Softwood pole replacements	200
McNamaras Rd rebuild	293
Temuka river crossing	76
Urban Feeder upgrade	65
WDS-BPD 110 kV double circuit	30
ABS replacements	135
New ABS's	60
Sub transmission lines reconductor to Iodine	451
ABS relocations (T537, ABS 1556)	25
New Connections & Subdivisions	2400
Transformers distribution for subdivisions, extensions & replacements	450
Voltage regulator & Capacitor Bank Installations	180
Distribution Sub refurbishment	220
Two pole distribution sub refurbish.	160
Replacement RMU's	380

Works programme project	Budget ('$000)
New RMU's	250
Reclosers New	200
Reclosers Replacements	100
Install CB for F321	100
Earthing	200
11/22 kV Substation Upgrade final stage	150
WDI Distribution substation	500
Underground Cable Upgrades (G)	300
Underground Cable Upgrades (R)	500
O/H to U/G conversions	470
Zone Substation Protection replacement	150
Mobile sub/gen site preparations	200
33/22 kV CB & recloser replacement	250
Ripple Plant replacement & LS rework	160
New 11 kV WDI CB & protection	80
New & Refurbishment of equipment	150
QOS Investigations	75
Zone Substation upgrade	100
33 kV Upgrade	500
Comms & RTU	100
11 kV protection/control replacement (17 CBs)	330
SCADA Master Station Modules	50
SCADA & pole top equipment automation (e.g. reclosers)	200
Upgrade Security starting with Zone Substations.	100
Consultants Investigations and Reports	350
Total	13,667

Appendix C Capex 10-year works plan from 2015/16

This appendix lists the works projects for the next 10 years.

Projects are listed in real (constant) dollars and in thousands ($,000.00).

Table C 3 Capex 10 year works plan

AEL Works Programme Projects	15/16 ('$000)	16/17 ('$000)	17/18 ('$000)	18/19 ('$000)	19/20 ('$000)	20/21 ('$000)	21/22 ('$000)	22/23 ('$000)	23/24 ('$000)	24/25 ('$000)
Distribution and LV lines	1208	2033	1597	1618	1200	1200	1200	1200	1200	1200
Distribution and LV lines	1300									
Distribution and LV lines	200									
Distribution and LV lines	80									
Distribution and LV lines	189									
Sub-transmission	200	200	200	200	200	200	200	200	200	200
Distribution and LV lines	293									
Distribution and LV lines	76									
Distribution and LV lines	65									
Sub-transmission	30	100	3500							
Distribution switchgear	135	120	135	120	100	100	100	100	100	100
Distribution switchgear	60	60	60	60	60	60	60	25	60	
Distribution and LV lines	451									
Distribution switchgear	25									
Other network assets	2400	2400	2400	2400	2400	2000	2000	2000	2000	2000
Distribution substations and transformers	450	450	400	400	350	350	300	300	300	250
Distribution substations and transformers	180	80	180	180	120	180	120	120	80	
Distribution substations and transformers	220	220	160	160	160	160	160	160	100	100
Distribution substations and transformers	160	160	160	160	160	160	160	160	100	100
Distribution switchgear	380	200	150	150	150	150	150	150	150	150
Distribution switchgear	250	250	250	250	250	250	250	250	250	250
Distribution switchgear	200	180	180	180	60	60	60	60	60	60
Distribution switchgear	100	100	122	122	122	122	122	60	60	60

AEL Works Programme Projects	15/16 ('$000)	16/17 ('$000)	17/18 ('$000)	18/19 ('$000)	19/20 ('$000)	20/21 ('$000)	21/22 ('$000)	22/23 ('$000)	23/24 ('$000)	24/25 ('$000)
Distribution switchgear	100									
Other network assets	200	100	100	100	100	100	100	100	100	100
Distribution substations and transformers	150									
Distribution substations and transformers	500									
Distribution and LV cables	300	300	300	300	350	300	300	300	300	300
Distribution and LV cables	500	220	220	220	300	300	300	300	300	300
Distribution and LV cables	470	250	2000	1000	1000	1000	1000	1000	1000	1000
Zone substations	150	150	200	150	150	150	200	200	200	
Zone substations	200	150								
Zone substations	250	200	150	150			150			
Other network assets	160	400								
Zone substations	80									
Other network assets	-		50	100						
Other network assets	150	150	150	150	150	150	150	150	150	150
Other network assets	75	75	100	125	125	125	125	100	100	100
Zone substations	100	1800								
Zone substations	500									
Sub-transmission		3100								
Other network assets	100	100	100	100	100	100	100	100	100	100
Zone substations	330									
Other network assets	50	100	50	50	50	50	50	50	50	50
Other network assets	200	200	100	150	150	150	150	150	150	150
Other network assets	100	100	100							0
Other network assets	350	250	150	150	150	150	200	100	100	150
Total	13,667	14,198	13,264	8,745	7,967	7,567	7,707	7,335	7,210	6,870

Appendix D Schedule 14a

Company Name	Alpine Energy Limited
For Year Ended	31 March 2015

Schedule 14a Mandatory Explanatory Notes on 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 not 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 2% per annum, on a straight-line basis, based on New Zealand Treasury forecasts. To derive the 10 year forecast. 2% was selected as a conservative inflationary rate. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 2% per year.

Commentary on difference between nominal and constant price 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 dollar terms the constant price forecasts were inflated by approximately 2% per annum, on a straight-line basis, based on New Zealand Treasury forecasts. To derive the 10 year forecast. 2% was selected as a conservative inflationary rate. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 2% 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 these 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 2% per year.

Appendix E Selection of equipment

Equipment is selected based on the theoretical and electrical characteristics as outlined in the previous sections—this 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 and in practical terms this translates to the following materials and equipment being specified and used.

E.1 Sub-transmission lines

For more information on sub-transmission lines please refer to the Major Network Asset Management Plan. Table 8.3 describes key characteristics of equipment chosen for sub-transmission lines.

Table 8.3 Characteristics of equipment used for 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.

E.2 Sub-transmission cables

For more information on sub-transmission cables please refer to the Major Network Asset Management Plan. Table 8.4 describes key characteristics of equipment chosen for sub-transmission cables.

Table 8.4 Characteristics of equipment used for 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.

E.3 Zone substations

For more information on zone substations please refer to the Major Network Asset Management Plan. Table 8.5 describes key characteristics of equipment chosen for zone substations.

Table 8.5 Characteristics of equipment used for 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. 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 this 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 set to cover them 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.

E.4 Distribution lines

Table 8.6 describes key characteristics of equipment chosen for distribution lines.

Table 8.6 Characteristics of equipment used for distribution 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 Ferret ACSR, 42.4 mm^2 Al equiv, 9.0 mm dia, 15.2 kN, 185/285 A at 50/75 °C Gopher ACSR, 26.2 mm^2 Al equiv, 7.1 mm dia, 9.6 kN, 115/165 A at 50/75 °C Magpie HSC, 10 mm^2 Al equiv, 6.33 mm dia, 17.8 kN, 60 A assessed The above ratings were largely taken (Magpie excluded) from the General Cables web page on 8/2/2010.
Poles	17 m, I beam, Humes ex Gladstone, 12 kN transverse working 10 to 15 m, Hardwood 8 kN and 12 kN 10 to 15 m, Softwood 9 kN and 12 kN 12.2 m 7.35 kN and 12.5 m 8 kN concrete I beam, ex Firth 9.5 and 11 m, prestressed concrete, ex Busck 9.7 and 10.7 m, mass reinforced concrete, NETcon (soon to be out of manufacture)
Insulators	Pin, bobbin, and stay insulators– general range of product from NZI catalogue. Strain insulators – generally glass disc ex Chinese manufacture.

E.5 Distribution cables

Table 8.7 describes key characteristics of equipment chosen for distribution cables.

Table 8.7 Characteristics of equipment used 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.

E.6 Distribution substations—pole mounted

For more information on distribution substations—pole mounted, please refer to the Major Network Asset Management Plan. Table 8.8 describes key characteristics of equipment chosen for distribution substations—pole mounted.

Table 8.8 Characteristics of equipment used for distribution substations—pole mounted

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. These 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, these have ratings up to about 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.

E.7 Distribution substations—ground and underground Mounted

We avoid the use of integrated substations; that is, substations with the HV switchgear included in the end box. If one component fails it is considered easier to replace one component than replace a complex site.

'T-Blade' type transformers are being sourced to eliminate legacy transformer end box located 11 kV HRC fused cable 'T' connections. The philosophy is also to have RMU then T-Blade then RMU then T-Blade, and so on. This aids sites that do not have sufficient space to install an RMU for the transformer tee off; it also reduces costs. A preference is that the T-Blade transformer connection has diversity in that it has its LV interconnected to other transformer's LV windings.

Table 8.9 describes key characteristics of equipment chosen for the selection of sites.

Table 8.9 Characteristics of site selection

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 secondaries to be run isolated from each other. This 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.

E.8 Low voltage reticulation

For information on LV reticulation please refer to section 3.3.9—LV reticulation Lines and cables, including link and distribution boxes, on page 74.

Table 8.10 describes key characteristics of equipment chosen for LV reticulation.

Table 8.10 Characteristics of equipment used 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 which 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.

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
LTNZ	—	Land Transport New Zealand

LV	—	Low Voltage
MDC	—	Mackenzie District Council
MDI	—	Maximum Demand Indication
MFE	—	Ministry for the Environment
MI	—	Mineral Insulated Cable
MT	—	Ministry of Transport
MVA	—	Mega Volt Ampere
MW	—	Mega Watt
Mvar	—	Mega Volt Ampere reactive
N-1	—	Reliability measure, where n systems can lose 1 element and still function normally
NDP	—	Network Development-plan Prioritisation process
NIWA	—	National Institute of Water and Atmosphere Research
NST	—	North Street Substation
NWL	—	Network Waitaki Limited
OAI	—	Orari Substation
OCB	—	Oil Circuit Breaker
OC	—	Overcurrent
ODL	—	Oceania Dairy Limited
ODV	—	Optimised Deprival Valuation
OCTC	—	Off Current Tap Changer
OLTC	—	On Load Tap Changer
Opex	—	Operating Expenditure (including maintenance spend)
OPU	—	Opuha
PAM	—	PAS 55 Assessment Methodology
PAR	—	Pareora Substation
PAS 55:2008	—	Publically Available Specification number 55
PCs	—	Desktop Computers
pd	—	potential difference
PD	—	Partial Discharge
PIL	—	Paper Insulated Lead
PILCSWA	—	Paper Insulated Lead Steel Wire Armoured cable
PLP	—	Pleasant Point Zone Substation
POS	—	Point Of Supply
pu	—	per unit

PWC	—	Price Waterhouse Coopers
RGA	—	Rangitata Substation
RMA	—	Resource Management Act
RMU	—	Ring Main Unit
RTU	—	Remote Terminal Unit
SAIDI	—	System Average Interruption Duration Index
SAIFI	—	System Average Interruption Frequency Index
SCADA	—	Supervisory Control and Data Acquisition
SCI	—	Statement of Corporate Intent
SEL	—	Schweitzer Engineering Laboratories
STA	—	St. Andrews Substation
STU	—	Studholme Transpower substation
SVC	—	Static Var Compensation
TDC	—	Timaru District Council
TEK	—	Tekapo Village Zone Substation
THD	—	Total Harmonic Distortion
TIM	—	Timaru Transpower substation
TKA	—	Tekapo Transpower substation
TMK	—	Temuka Transpower substation
TPNZ	—	Transpower
TVS	—	Twizel Village substation
TWZ	—	Twizel Transpower substation
UHF	—	Ultra high frequency
UHT	—	Unwin Hut Zone Substation
V	—	Volts
VCB	—	Vacuum Circuit Breaker
VHF	—	very high frequency
VLF	—	very low frequency
WDC	—	Waimate District Council
WHO	—	Waihao Substation
WTE	—	Waimate Substation
XLPE	—	cross linked polyethylene cable
YNd9	—	Transformer vector group

Alpine Energy Limited
Meadows Road
PO Box 530, Timaru 7940
New Zealand

Tel: +64 3 687 4300
Fax: +64 3 684 8261
Web: www.alpineenergy.co.nz