ALPINE ENERGY LIMITED

Asset Management Plan

2014 – 2024

Asset Management Plan 2014–2024

Approved 27 March 2014

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Foreword

The purpose of our 2014 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 1950's and 1960's 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 eight 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 are developments are identified to best serve our consumers for the next 50 years (the average life of an electricity distribution asset).

We have restructured our tariffs and pricing methodology to allow 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.

We encourage consumers to comment on our AMP and 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 – 27 March 2014.

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 2013 to 2023

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 2014 to 2024 of Alpine Energy Limited prepared for the purposes of clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

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

Stephen Richard Thompson	Alister John France
27 March 2014	27 March 2014

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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.

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 are at a high of 2.88%[1], up from 2.66% in December 2013 and 2.65% of a year ago.[2]

New Zealand's interest rates did not rise significantly during 2013–14. These low interest rate conditions support the investment rates as proposed in our AMP.

There are signals that interest rates may begin to rise during 2014 as inflationary pressures from outside increase their effect on the New Zealand economy. The ANZ Regional Trends report of November 2013 reported quickened year–on year economic growth in all but one region, lifting to its strongest rate of increase since December 2004.

Canterbury was the only region to record a slowing annual rate of economic growth, but at 6.2% its growth rate still overshadows all other regions[3]. The report noted that business sentiment in Canterbury continued to improve, supported by strength in the construction industry and commercial property. Record dairy pay-outs are expected to inject capital into the rural sector.

The BNZ's Markets Outlook report of 13 January 2014 has estimated the GDP growth in 2013 at 2.7% (compared with 2% generally since 2010). They estimate the GDP annual average growth in 2014 will be 3.9%.

[1] As at 13 January 2014.
[2] Refer to the Reserve Bank of New Zealand's (RBNZ) latest Financial Stability Report of November 2013 for details of the RBNZ's current view of the New Zealand economy.
[3] Compared to 6.5% for the year to June 2013.

1.2.1.1 Meeting Increasing Demand

New connection demand for additional load was steady in 2013 for irrigation and dairy conversions. 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.

High commodity prices are benefiting the economy and growing the network despite the deflationary impact of the high exchange rate. 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, resource consents for irrigation schemes. Appendix B at page 329, 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 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 + 10% in each year. The DPP requires us to increase prices by CPI + 10% 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 2014 to 31 March 2024 and was approved by our board on the 28 March 2014. Our AMP was publicly disclosed by the 31st of March 2014 in accordance with the Electricity Distribution Information Disclosure Determination 2012.

1.4 Asset Management Systems

The Publically Avaliable 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
- Service Level 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 Figure 3.1 on page 37. Our asset based 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 750 GWh of energy a year, and had a half hour average coincident Maximum Demand of 127 MW recorded in February 2013. Energy consumption is up from the previous high of 708 GWh and the maximum demand is slightly down from 113 MW experienced in May 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 set 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 lesser 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 ten years. The figures are a summary of Appendix C at page 333. Costs are GST exclusive and in constant (real) dollars.

1.8 Life Cycle Asset Management

Databases hold age information on existing assets 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 Operation and Maintenance Expenditure

Network asset OPEX is summarised in Table 1.3 at page 10. Total maintenance expenditure is forecast to be constant through most of the planning period.

1.10 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.

1.10.1 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.

1.10.2 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.

1.10.3 Environment

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

1.11 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.

1.12 Expenditure Forecast

The following section summarises our OPEX and CAPEX for the next 10 years, as well as including discussion on uncertainty, variance analysis and the use of nominal/real dollar terms.

1.12.1 Management of Uncertainty

The statistics relating to performance against plan are taken from the last financial year summary details (2012–2013) 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 below.

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

1.12.2 Expenditure Forecasts and Reconciliation

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% 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).

Forecast variance for the 2012–13

Table 1.2 over page, shows the variance between forecast expenditure and actual expenditure for the 2012–13 year.

Information required by clause 2.6.5 and attachment A of the Information Disclosure Determination 2012 are provided at in detail in the Commerce Commission Schedules 11a and 11b. A copy of the schedule in Excel format is available on our website.

Table 1.2 Variance between actual expenditure and the previous year forecast

Variance between actual expenditure and previous year forecasts	Actual ('$000) 2012–13	Forecast ('$000) 2012–13	Variance As a %
Capital Expenditure			
Customer Connection	6,975	2,250	210%
System Growth	17,056	6,339	169%
Asset Replacement and Renewal	2,097	5,516	-62%
Reliability, Safety and Environment	2	0	Infinite increase
Asset Relocations	2,280	2,325	-2%
Subtotal – Capital expenditure on network assets	*28,411*	*16,430*	73%
Operating Expenditure			
Service Interruptions and Emergencies	1,208	1,127	7%
Vegetation Management	95	103	-8%
Routine and Corrective Maintenance and Inspection	2,322	2,475	-6%
Asset Replacement and Renewal	378	1,539	-75%
Subtotal – Operating Expenditure on Asset Management	*4,003*	*5,245*	-24%
Total Direct Expenditure on asset Management	**32,414**	**21,675**	**-33%**

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Table 1.3 AMP forecast expenditure 2013 – 2019 (in $'000 and constant prices)

Expenditure	Actual	Forecast										
	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Capital												
Customer connection	6,975	2,703	2,890	2,850	2,850	2,850	2,850	2,850	2,850	2,850	2,850	2,850
System growth	17,056	9,228	4,405	3,030	2,730	4,530	1,030	1,020	1,030	1,020	920	1,305
Asset replacement and renewal	2,097	3,524	4,760	3,705	4,085	4,127	4,597	5,602	4,602	4,802	4,590	4,470
Asset relocations	2	-	150	-	-	-	-	-	-	-	-	-
Reliability, safety and environment	2,280	5,841	1,865	1,240	890	440	490	370	370	370	335	370
Subtotal – network CAPEX	**28,411**	**21,295**	**14,070**	**10,825**	**10,555**	**11,947**	**8,967**	**9,842**	**8,852**	**9,042**	**8,695**	**8,995**
Capex on non- network assets	447	1,312	942	747	697	372	597	397	392	372	372	372
Total CAPEX	**28,858**	**22,607**	**15,012**	**11,572**	**11,252**	**12,319**	**9,564**	**10,239**	**9,244**	**9,414**	**9,067**	**9,367**
Operating												
Service interruptions and emergencies	1,208	1,485	1,876	1,857	1,819	1,781	1,744	1,706	1,668	1,630	1,592	1,585
Vegetation management	95	123	113	112	110	107	105	103	101	98	96	96
Routine and corrective maintenance	2,322	2,946	2,829	2,801	2,744	2,687	2,629	2,572	2,515	2,458	2,401	2,390
Asset replacement and renewal	378	798	589	583	571	559	547	535	523	512	500	498
Subtotal – network OPEX	**4,003**	**5,352**	**5,408**	**5,353**	**5,244**	**5,135**	**5,025**	**4,916**	**4,807**	**4,698**	**4,588**	**4,569**
Opex on non-network assets	8,298	9,141	9,257	9,629	9,705	9,597	9,554	9,531	9,437	9,431	9,428	9,425
Total OPEX	**12,301**	**14,492**	**14,665**	**14,982**	**14,948**	**14,732**	**14,579**	**14,447**	**14,244**	**14,129**	**14,016**	**13,993**
Total Expenditure on Assets	**41,159**	**37,099**	**29,677**	**26,554**	**26,200**	**27,051**	**24,143**	**24,686**	**23,488**	**23,543**	**23,083**	**23,360**

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

2 Background and Objectives of the Asset Management Plan

2.1 Introduction

The AMP summarises and guides all asset management behaviour. It acts as a framework for asset management policies, strategies, and plans by:

- promoting asset management policies and objectives
- linking organisational strategic objectives
- guiding the asset management priorities.

This chapter states the purpose of the AMP and our mission statement in detail and shows how this purpose promotes and is consistent with our business's strategic plans and objectives.

2.2 Purpose of the AMP

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

- Set service levels that meet stakeholder expectations and our 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.
- Have appropriately identified risks and have adequate processes in place to mitigate those risks.
- Have made adequate 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, Goals and Objectives

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.

Our mission statement is a concise summary of our strategic goals and objectives which have been developed to ensure that our key stakeholder requirements are met. Our strategic goals and objectives, as developed from our stakeholder requirements, are for:

- Shareholders—to maximise the value of the company.
- Customers—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.

2.3.1 Asset Management Strategy

Our asset management strategy describes the asset management processes (actions) that should be undertaken to achieve our strategic goals and objectives. The asset management strategy is not a formalised document but is inherent throughout the AMP. At present we are further developing our systems and processes including developing formal linkages between strategies, policies and actions. For further information please see section 8.3 Continuous Improvement at page 235.

The asset management strategy and therefore our asset management processes and actions form the bulk of the AMP. The AMP describes the strategy that we will use to meet our mission of commercial success in the delivery of energy and therefore meet our stakeholder requirements for safe, efficient, reliable and cost effective energy delivery.

This strategy includes an in depth understanding of:

- our asset base—see Chapter 3 at page 35
- levels of service and performance—see Chapter 4 at page 83
- forecasting and planning—see Chapter 5 at page 103
- life cycle management—see Chapter 0 at page 158

- risk management—see Chapter 7 at page 209.

This process (from stakeholder objectives to asset management activities) is summarised in Figure 2.1 below.

Figure 2.1 Development Asset Strategy

2014 Asset Strategy

Our 2014 asset management strategy includes the following actions:

- Maintain awareness of safety around electricity to the forefront for company and customers.
- Assist Transpower to upgrade and maintain Timaru as an 11 kV GXP for the foreseeable future.
- Look to use the proximity of Transpower's EHV circuits in the South Canterbury area to connect emerging loads as opposed building 33 kV sub-transmission from existing GXPs. Look to take either 220 kV or 110 kV supply directly from Transpower so we can transform the EHV to a suitable distribution potential at the zone substation.
- Assist Transpower with plans for improved supply capacity while sharing risk of pre-contingent events.
- Develop our network to ensure adequate performance (including load capacity and voltage regulation) of sub-transmission lines, zone substations, distribution lines, distribution substations, LV reticulation, and of other ancillary plant used for the operation, management and control of the network.

- Maintain, to the required standard, the condition of the Network, its components, and its support systems.
- Improve reliability of supply to consumers through high voltage feeder efficiency and the automation of remotely located circuit breakers and reclosers.
- Maintain power quality through modelling of network performance, and assessments through power quality measurements.
- Ensure future revenues balance an equitable return on capital investment.

2.4 Development of Strategic Goals and Objectives

2.4.1 Stakeholder Influence

Our goals and objectives are directed and influenced by our owners and other stakeholders.

We retain close contact with our key stakeholders and stakeholder feedback is essential to guide our decision making and to manage competing stakeholder interests.

We are jointly owned by the Line Trust South Canterbury and by Mackenzie, Timaru, and Waimate District Councils. Our stakeholder interests and how we accommodate those interests are described in Table 2.1 below.

Table 2.1 Identification and management of stakeholder expectations

Stakeholder	Identification and management of expectations	Interests
Lines Trust South Canterbury	By their approval or required amendment of the Statement of Corporate Intent Regular meetings between the directors and the trustees	Health and Safety Financial return Price Quality of supply Compliance
Councils (as shareholders)	By their approval or required amendment of the SCI Regular meetings between the directors and the trustees	Health and Safety Financial return Price Quality of supply Compliance
Retailers	Annual consultation with retailers	Price Quality of supply Low Transaction costs
Electricity consumers	Informal contact with group representatives	Health and Safety Price Quality of supply Compliance

Stakeholder	Identification and management of expectations	Interests
Employees and contractors	Regular staff briefings Regular contractor meetings Normal course of business interactions	Health and Safety Training and development Compliance Price Quality of supply
Public, iwi and landowners	Informal talk Media presentations/information disseminations Local advertising and sponsorship Feedback from the Trust's public meetings	Health and Safety Quality of supply Respect for cultural and environmental issues Land access
Commerce Commision	Regular bulletins on various matters Release of discussion papers Feedback through industry working groups Analysis of submissions on discussion papers	Financial return Price Quality of supply Good governance Compliance
Electricity Authourity	Weekly update through market brief Release of consultation papers Consulation and submission process	Compliance to the Electricity Participation Code
Other State bodies and regulators	Regular meetings Newsletters	Health and Safety Industry Standards Compliance
Local Bodies as regulators	Meetings Newsletters, media District and regional plans	Environmental Compliance
Embedded Networks	Formally as necessary to discuss common issues (assets on Council land or CDEMG)	Health and Safety Financial return Price Quality of supply Compliance
Transpower	Formally as required Industry working groups	Health and Safety GXP loads Quality of supply Compliance
Embedded generators	Regular bulletins on various matters Release of discussion papers Feedback through industry working groups Analysis of submissions on discussion papers	Health and Safety Financial return Price Quality of supply Compliance

2.4.1.1 Accommodating Stake Holder Interests

Our common stakeholder are summarised at Table 2.2 below.

Table 2.2 Accommodating stakeholder interests

Interest	Description	How we accommodate interests
Viability	Viability is necessary to ensure that the shareholders and other providers of finance such as bankers 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 on employed capital our owners could obtain from a term deposit at the bank plus a margin to reflect the risks to capital in an ever-increasingly regulated lines sector.
Price	Price is a key means of both gathering revenue and signalling underlying costs. Getting prices wrong has economic implications for both us and our stakeholders.	Our total revenue is constrained by the price path under default/customised price-quality regulation. Breaches of the price-path can result in pecuniary penalties of up to five million dollars to companies and $500,000 for individuals. Failure to gather sufficient revenue to fund reliable assets will interfere with consumer's business activities, and conversely gathering too much revenue will result in an unjustified transfer of wealth from consumers to shareholders. Price is economical regulated by the Commerce Commission 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. Issues such as the Low Fixed Charges requirements can distort a cost effective pricing methodology.
Supply quality	Emphasis on continuity, restoration, maintaining voltage and reducing voltage drops is essential to minimising interruptions or maintaining a reasonable supply quality to consumers businesses.	We will accommodate our stakeholders' needs for supply quality by focusing resources on quality, continuity and restoration. Previous customer surveys conducted all reveal that continuity and restoration of supply are the supply attributes that customers value the most. We will endeavour to comply with the quality standards under the default price-quality path during each regulatory year.

Interest	Description	How we accommodate interests
Safety	Staff, contractors and the public at large must be able to move around and work on our network in total safety.	We will ensure that the public at large is kept safe by ensuring that all above-ground assets are structurally sound, live conductors are well out of reach, all enclosures are kept locked, and all exposed metal is 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. Motorists will be kept safe by ensuring that above-ground structures within the carriageway are kept as far as reasonably practicable from the centre of the carriage way within the constraints of road reserves and private property.
Compliance	We must comply with many statutory requirements ranging from safety to the annual disclosure of information.	We will ensure that all safety issues are adequately documented and available for inspection by authorised agencies. We will disclose information so as to comply with the information disclosure requirements.
Efficient operation	Operating the business and managing costs efficiently	We plan to instigate a programme to significantly upgrade our Asset Management Systems so as to more effectively monitor and control the need for, and allocation, and use of resources for the implementation of its capital, maintenance, and operation programmes.

2.4.1.2 Managing Conflicting Interests

Conflicting stakeholder interests are managed taking account of how they impact on the following hierarchy of priorities:

- Safety
- Reliability
- Efficiency
- Compliance
- Financial return

2.4.2 Other Drivers of Planning

Our strategic goals and objectives are driven by the following key factors:

- safety requirements
- commercial goals for earning an appropriate return
- service quality and revenue within the regulatory targets
- competitive pressures from other lines companies

- environmental regulation
- advancing technologies, such as distributed generation and smart metering
- changing climatic conditions
- economic trends and indicators, both locally and globally
- appropriately skilled resources are available
- technical and industry requirements
- asset configuration, condition, and deterioration
- physical characteristics of the network
- effect of wind, salt spray, ice and snow on the network.

Two drivers which have a high impact on strategic development are the prevailing regulatory environment and climate change. These are both expanded upon below.

2.4.2.1 Prevailing Regulatory Environment

We have to comply with regulations which ensure the purpose of Part 4 of the Commerce Act 1986 is met. These regulations include both the information disclosure and default price–quality path (DPP) requirements.

It is the information disclosure requirements that requires us to annually supply information on reliability, performance, prices and planned spending.

The DPP places a ceiling on the allowable revenue we can recover each year. We can increase our average price by CPI + 10% each year until a reset of our revenue cap occurs on 1 April 2015. The new reset will apply for 5 years.

2.4.2.2 Climate Change

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.

The effects of climate change on our network assets may include:

- Changes in maximum demand and in seasonal and regional load patterns.
- Changes in energy consumption.
- Changes in accessibility of existing network assets for maintenance and new network asset sites for construction.
- Increased risk of damage to network assets from extreme weather conditions such as wind storms, snow storms, floods, heavy rain (land slips affecting poles), etc.
- Changes in growth of vegetation affecting the growth of vegetation near our network assets and the management of that vegetation.

- Increased risk of damage to our network assets located in or near waterways that may change flood patterns.
- Possible changes in the habits and patterns of birds and other wildlife that may affect the security of network assets[4].
- Sea level changes may affect our network assets where these are located on low lying coastal land that may be subject to sea erosion or flooding.

2.5 Planning Assumptions

Our planning also takes into account significant assumptions about the social, economic, and political environment in which we work. The assumptions can are listed at Table 2.3 below and are used for planning in section 5.3.7.

Table 2.3 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.	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.

[4] Large birds causing line clashes, insulation damage from birds and opossums, etc.

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.
The return on milk fats will not alter significantly.	A significant change in the value of milk fats could lead to changes in land use and therefore irrigation use impacting on load requirements.	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.	May require further investment and an increase in line charges to cover costs associated with DG.

2.6 Key Planning Documents

Our key planning documents set out the actions and strategies 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.

The interaction of our key planning documents with our strategic goals, objectives and stakeholder interests can be seen in Figure 2.2, over page.

2.6.1 Statement of Corporate Intent

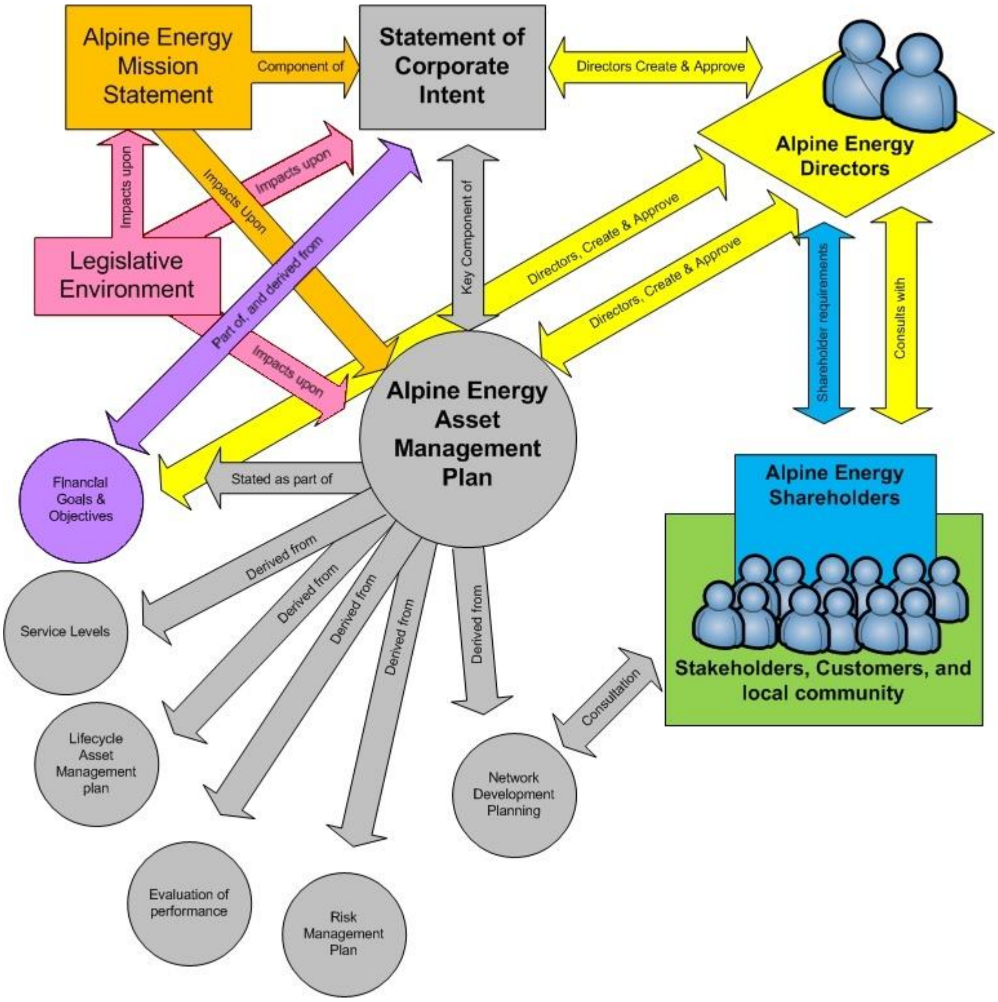
The Statement of Corporate Intent (SCI) forms the principal accountability mechanism between our board and shareholders. It sets out our overall intentions and objectives. It is prepared annually and forecasts out to a three year period.

SCI intentions and objectives include our:

- company objectives including mission statement, vision, values, goals and objectives
- nature and scope of activities to be undertaken

- proprietorship ratio
- accounting policies
- financial performance targets
- operating performance targets
- dividend distribution policy
- information to be provided to shareholders
- procedures for acquisition of interests in other companies or organisations
- transaction details

Figure 2.2 Interaction of key processes and entities



2.6.2 Strategic Management Plan

Senior managers manage assets under their control to provide the required level of service or economic benefit at the lowest possible long-term cost. To achieve this, senior engineering management develop strategic asset management plans that cover:-

- alignment with the Integrated Development Plan
- operational guidelines
- performance monitoring

- maintenance programs
- renewal, refurbishment and replacement plans
- disposal and rehabilitation plans
- operational, financial and capital support requirements
- risk mitigation plans including insurance strategies
- reporting of emerging issues
- verification of asset,
- replacement of assets
- movement of assets
- whole of life consideration.

The operational budgets are the short to medium term plan for implementing this strategic management plan.

2.6.3 Asset Management Plan

The AMP describes the actions and strategies to achieve our strategic goals and objectives. These actions and strategies include an in depth understanding of our asset base (Chapter 3), levels of service and performance (Chapter 4), forecasting and planning (Chapter 5), life cycle management (Chapter 0), and risk management (Chapter 7).

2.6.4 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 it also contributes to long term planning.

The works plan also details how a project should be implemented. Projects in the works plan reflect projects described in the AMP.

2.6.5 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 the AMP with the SMS is shown in Figure 7.1 at page 211.

2.7 Asset Management Systems and Processes

Our asset management systems and processes are the formal and informal methods used to manage asset data and information to achieve our strategic goals and objectives. This section summarises the present state of our asset management systems and processes.

We are also required to provide information on the state of our asset maturity including our systems and processes as part of the Information Disclosure regulatory requirements. This ‘self-assessment' is found in Chapter 8 (schedule 13, Report on Asset Management Maturity). This assessment identified that our systems and processes for life cycle asset management need to be further established and developed.

2.7.1 Key Systems and Processes

The present state of asset management systems and processes is found below. Further detail on Life Cycle Asset Management is found in Chapter 0. We are enhancing our systems and processes, for further information please refer to Chapter 8.

2.7.1.1 Information Technology for Asset Management

Our IT systems specific to asset management are described in Table 2.4 below.

Table 2.4 Description of information technology databases

System	Tasks/Data provided	Linkages
GIS	Pole and conductor data Location of all network assets	Links to gentrac and ICP database. The ICP database updates address information in GIS.
gentrac (note this is an in house version)	Asset 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	Standalone
Nimbus	Accounting and asset register	Standalone

2.7.1.2 Operating Processes and Systems

The operating processes and systems are based on industry standard procedures to ensure safety to personnel, public and plant. This involves trained staff who have an appreciation of the equipment involved, its ratings, the operating modes and the safety procedures which apply when using the equipment.

The EEA Safety Manual – Electricity Industry (SM-EI) is a fundamental document as well as containing our internal operating procedures and a means of sharing knowledge with other network companies on safe working practices and network control and operating procedures.

2.7.1.3 Maintenance Processes and Systems

Maintenance processes are based on manufacturer's equipment specifications and maintenance requirements. Generally the age and condition of the equipment or components are assessed and from the evaluation the part is either replaced, refurbished, maintained or recorded as in good condition subject to the next scheduled inspection.

The present maintenance systems are generally manual and paper based, (maintenance and test cards, test reports, and spread sheet schedules) with the assistance of Nimbus (a project, job and order creation and invoice payment) accounting system, gentrac (legacy asset database) software system, GIS database, spread sheets, and email. The development of specific purpose based and integrated asset maintenance software following completion of the recently initiated IT Review Project will provide additional benefits and efficiencies to our current practices.

The routine maintenance is undertaken largely by our prime contractor, Netcon, using detailed planning maintenance schedules for our substations and plant. These schedules are held, maintained and operated by Netcon for ourselves within spread sheets.

This routine inspection and maintenance work is monitored through to completion and approval for payment of invoice by our Asset Group and Engineering Group staff with the assistance of the Nimbus accounting system.

In 2011, we replaced the legacy jobbing accounts system (Intec) and a manually operated OPEX spread sheet with a new Nimbus accounting system. In addition to the New Connections chargeable jobs, and CAPEX project jobs, the Nimbus system is used for our management of all OPEX maintenance. This Nimbus accounting system includes for project, job, and order creation, job and purchase order reporting, and suppliers' invoice payments. Spread sheets are still used to assist with planning, of the maintenance work.

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

2.7.1.4 Renewal Processes and Systems

When the assessments indicate that an existing asset has insufficient safety margin to continue for a defined service period, then the item is scheduled for renewal. Often, assets will age or exhibit deterioration at different rates and there is a decision of replacing an entire series of assets or individual assets on successive visits. The economics of either approach needs to be evaluated on a case–by–case basis, and also account for the risk of extending the assets' service life.

Inspection programs for overhead lines are routinely undertaken and the remaining strength of the support pole assessed to determine end of life and application of an adequate safety factor to allow replacement before failure.

Substation and plant inspections are undertaken either by Netcon within their routine maintenance programme, or from specific condition assessment inspections ordered for specific types of plant by our Asset Group, or by unscheduled inspections by our engineering staff. Their inspections generate information that is collated manually, reviewed and assessed by us and which may result in planning decisions by our engineering and Asset Groups to initiate a project within the AMP for the refurbishment or renewal of the asset in question.

2.7.1.5 Up-Sizing or Extension Processes and Systems

Load growth often consumes capacity headroom, so forecasting and network modelling tools provide an element of predictability for when network feeders need to be supported with capacitors, regulators, re-conducted with larger wire, or zone substation transformers increased in size.

Network modelling software programs like ETap provide a valuable tool for forecasting when up-sizing is required when voltage performance limits are reached on substation feeders.

For further information on our planning processes please refer to section 5.2.

2.7.1.6 Reliability Enhancement Processes and Systems

Taking a review of faults and investigating their causes provides insight into how the impact of supply interruption can be reduced or avoided.

Improving security of supply level for larger loads is a well understood approach and documented in security of supply standards (EEA Guide). However, the analysis of risk in the local network context may influence the interpretation of industry standards, and modify the local response to take account of the special nature of our network compared with the average or ideal networks modelled in such industry standards.

The local geography, demography, distribution of load types, weather, earthquake risk, contractor's available technical resources, and other factors may, when evaluated in risk calculations, produce different security of supply levels for individual sites or installations from those suggested by a universal industrial standard.

Each year the 10 worst performing feeders are reviewed to determine the supply failure mode and what remedy can be implemented to reduce reoccurrence.

This may require introducing an additional feeder, splitting urban areas from rural areas to avoid remote rural faults affected urban areas or installing additional re-closer equipment to reduce the number of customers affected by a single fault.

Equipment selection also has a bearing on service, maintenance, and availability factors which underpin reliability.

2.7.1.7 OHUG Processes and Systems

Conversion of overhead lines to underground cable systems has in the past required assistance from another utility or council to contribute to the costs of the project.

Where the overhead line has reached an age or condition for replacement, which may be determined by increased load, then economics of replacing the new asset as an underground system is considered. Generally there is no strong financial benefit for transfer of overhead assets into underground services, but if undergrounding is required for engineering or safety reasons, this forms the justification for the expenditure.

2.7.1.8 Retirement Processes and Systems

Improvements in technology or construction materials can render some older assets obsolete as their condition, operability or cost to maintain in a serviceable condition becomes prohibitive.

Increasing demand can result in equipment ratings levels being exceeded, requiring replacement of the asset for safety reasons.

2.7.1.9 Wider Business Processes and Systems

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

The finance system records the job process, receiving the deposit payment and issuing the final receipt.

The majority of the components of this system are legacy items of types that were standard for small to medium enterprises.

The replacement system proposed by the present IT Review is expected to be of a type that is standard, at least in form, to modern medium enterprises but which will respond to the particular needs of an electrical distribution network business.

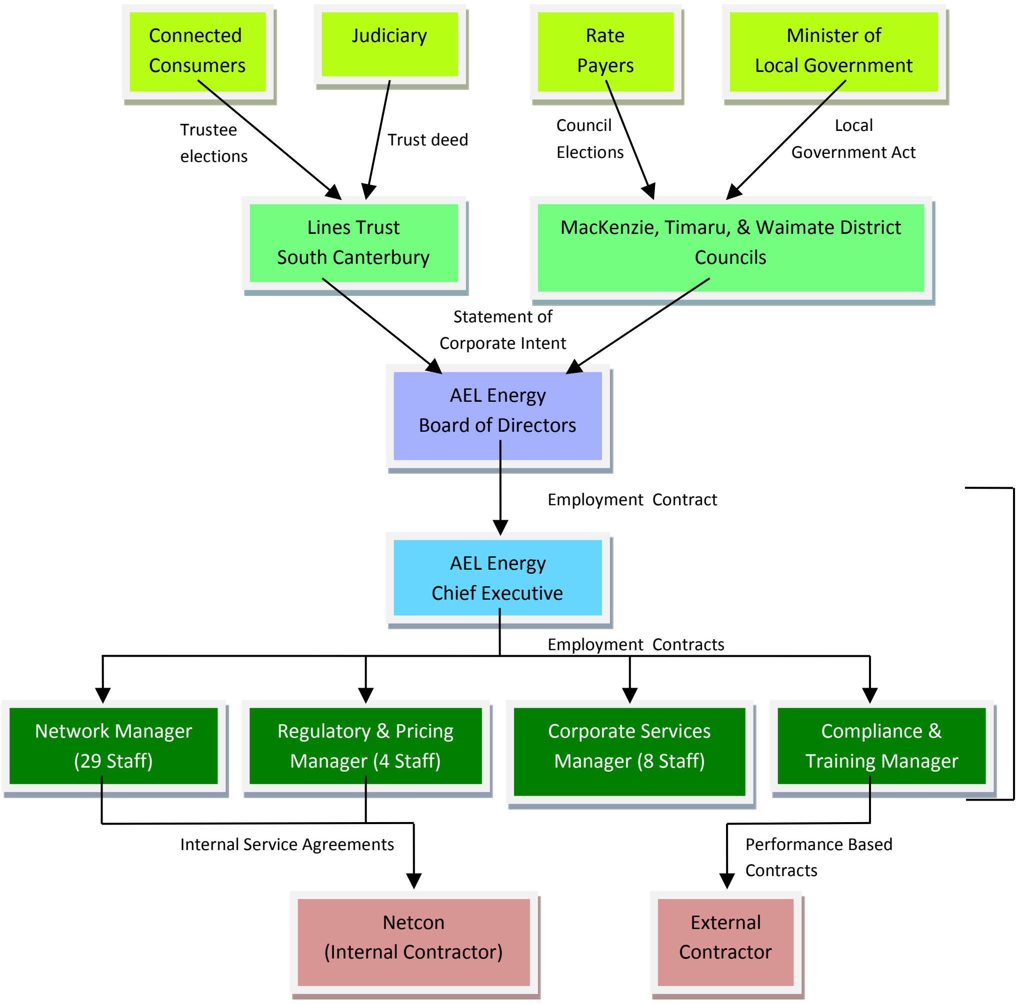
Document control

We are looking to enhance our document control and review processes, for further information please refer to Chapter 8.

2.8 Accountabilities for Asset Management

Our asset management accountabilities and accountability mechanisms are shown in Figure 2.3 below. These are more fully discussed in detail in the following sections.

Figure 2.3 Accountabilities for asset management



2.8.1 Accountability at Ownership Level

We have four shareholders – a trust and 3 district councils:

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

The trust is subject to an election process and the trust deed which holds all trustees collectively accountable to the New Zealand judiciary for compliance with the deed

The three 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.

The four shareholders have also entered into a deed as permitted by our constitution that inter alia restricts the sale of our shares and determines how our directors will be appointed.

2.8.2 Accountability at Governance Level

Our directors are accountable to the four shareholders through the Statement of Corporate Intent (SCI). Because the SCI includes projected revenue and reliability measures the four shareholders are intimately informed of intended price-quality trade–offs. We presently have five directors who are appointed as follows:

- 2 directors appointed by the Trust.
- 2 directors appointed by the Timaru District Council.
- 1 director appointed jointly by the Mackenzie and Waimate District Councils.

2.8.3 Accountability at Executive Level

The Chief Executive is accountable to the directors through his employment contract which sets out leadership of the organization and inter alia key business performance targets to meet SCI objectives.

2.8.4 Accountability at Management Level

Asset management is divided into four areas of accountability

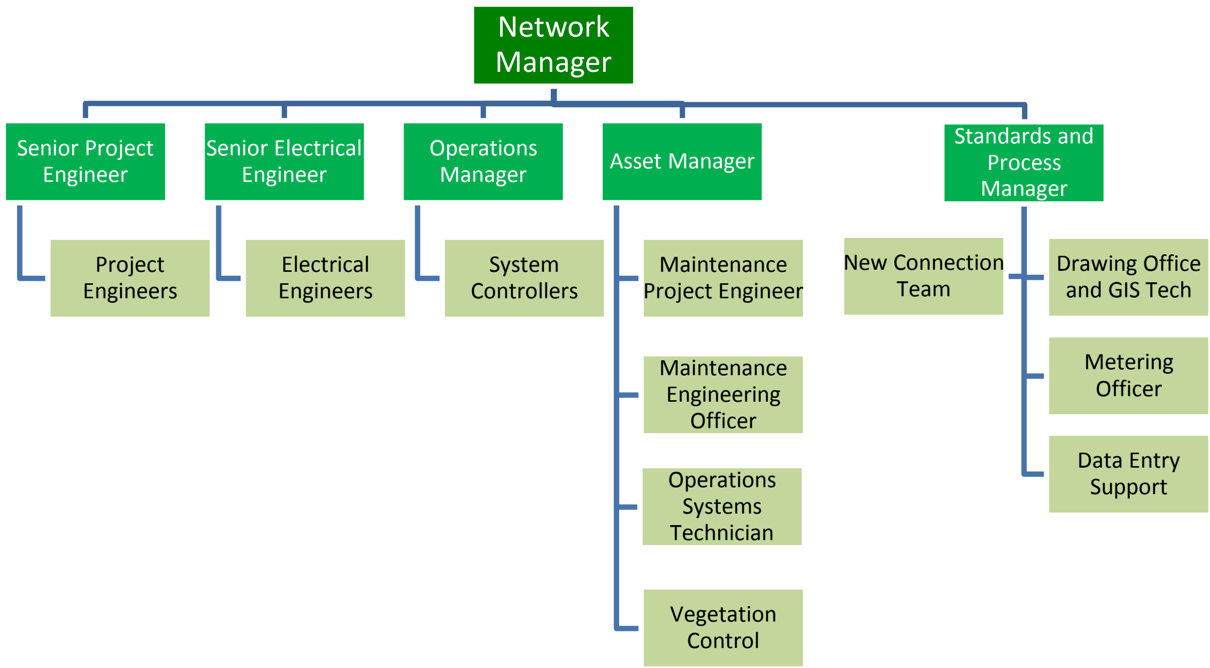
2.8.4.1 Network Manager

The Operations Manager, Asset Manager, Senior Electrical Engineer, Senior Project Engineer, and the Standards and Process Manager report to the Network Manager. The accountabilities of the asset management team are provided in Figure 2.4 over page.

2.8.4.2 Operations Manager

Accountability for the real time operations and restoration of supply lies with the Operations Manager, principally through the operations team, comprising management of the day to day running of the network, including control, operating, reporting and dispatch of switching and fault response work to contractors. This role depends on the nature and configuration of assets decided upon by the Network Manager and the Asset Manager.

Figure 2.4 Accountabilities of asset management at network level



2.8.4.3 *Asset Manager*

Accountability for managing the existing network assets lies with the Asset Manager. This role is clearly delineated to managing the lifecycle activities of existing assets (and includes support for operations as noted above). The Asset Manager is also responsible for editing and co-ordinating the preparation of the annual AMP for the CEO and Board of Directors.

2.8.4.4 *Senior Electrical Engineer*

Accountability for the development of new network assets lies with the Senior Electrical Engineer. This role addresses long-term planning issues such as capacity, security and asset configuration and also has relationships with operation. The Senior Electrical Engineer has a pivotal role in the preparation of the annual AMP.

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

The key accountabilities of the four second tier managers are to the CEO through their respective employment contracts which sets out performance targets based around business goals of meeting budgets and reliability standards.

2.8.4.5 *Standards and Process Engineer*

The Standards and Process Manager is tasked with ensuring that our standards are up to date and our processes are at a maturity determined by senior management. This manager is also responsible for the New Connections, and Drawing Office (including GIS) teams, as well as metering.

2.8.4.6 Compliance & Training Manager

Accountability for management of the Health & Safety Management System and for coordination of staff training and development lies with the Compliance & Training Manager. This role advises and facilitates on matters of compliance with regulatory requirements and industry standards.

2.8.4.7 Corporate Services Manager

Accountability for all corporate services and financial activities lies with the Corporate Services Manager. This role provides monitoring of the SCI and fiscal awareness as well as assisting with asset funding provisions and budgeting phases of the AMP.

2.8.4.8 Regulatory and Pricing Manager

The Regulatory and Pricing Manager is responsible for reporting against our compliance obligations to the Commerce Commission and Electricity Authority; and the setting and monitoring of our lines charges and pricing methodology.

2.8.5 Accountability at Works Implementation Level

2.8.5.1 Netcon Limited

Netcon Limited (Netcon), a subsidiary wholly owned by us is accountable through an internal service level agreement. External contractors are accountable through performance based contracts.

Netcon is the preferred network contractor for capital and maintenance services in the South Canterbury area.

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.

2.8.6 Key Reporting Lines

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

Our Board of Directors receive a monthly report from management outlining financial, operational, corporate, regulatory, and safety performance as well as progress to the annual plan of maintenance and capital activities. All SAIDI and SAIFI measures are reported monthly as well as progress on significant CAPEX projects (over $500 K). 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 group under leadership of the senior electrical engineer. GIS and draughting services, network maintenance management, and new connections services are provided by the commercial and regulatory and pricing groups. Corporate services provide financial, database and analytical assistance. The operations group provides operational experience and knowledge of the physical condition of equipment. Safety, compliance, and training services are provided by the compliance and training group.

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

The Board reviews and approves the annual AMP before it is published in March of each year.

2.8.7 Our Operating Structure

Our operations base is located at 33 Meadows Rd, Washdyke, Timaru. The site is also the base for Netcon. In addition to the main depot in Timaru, we operate one remote depot in Tekapo. This remote depot forms the base for the contractor for operations group work.

2.8.7.1 Network Group

The Network Group consists of the operations group, the asset group, the engineering group, and the process and standards group.

Operations Team

The Operations Team collectively provides planning, operating, and management of fault response services to ensure high levels of customer service are maintained throughout the region. The Operations Group provides valuable feedback as part of the asset management process by providing practical safety, operation and equipment performance/condition information that helps refine equipment and procedures. The Operations Group also provides a conduit for consumer feed-back collected by the contractors' operational staff, especially in rural areas when outages are being programmed, or with regard to asset condition or asset performance.

Asset Management Group

Asset management is driven from the Asset Group. This group is responsible for all existing primary and secondary electrical assets. This 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. This group has an important interest in the proposed new asset management system, particularly as it relates to the status and maintenance of the network assets, and Netcon's interaction with the new system.

Engineering Group

The Engineering Group are responsible for the strategic planning for new capital works and assets required to meet growth and other changing needs of our network. The engineering group is also responsible for detailed planning, design, acquisition, installation and commissioning of new capital plant assets.

Process and Standards Group

The Process and Standards Group are responsible for the design and commercial management of new connections and extensions to the network, undertaken from within the New Connections Section. They are also responsible for 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, undertaken from within the GIS and Draughting Office.

A further objective of the Process and Standards Group is to drive the business process mapping, and its reviewing, and implementation, for the proposed new asset management system. A large percentage of the business processes within this new system will be processes that are used by the operation and management of the GIS and asset database, and by the new connections business.

2.8.7.2 Corporate Services Group

The Corporate Services Group manages the financial, accounting, and IT system functions. Corporate services also provide contract and financial analysis and expertise for items outside the network's routine work. Some human resource and other administrative functions are managed by the corporate services group.

2.8.7.3 Regulatory and Pricing Group

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

2.8.7.4 Compliance and Training Manager

The Compliance and Training Manager manages compliance and training matters, and champions our health and safety culture through promotion of best practice and continuous improvement of safety on the network. The manager is also responsible for ensuring that Netcon or any other people working on the network, are authorised to access the network and complete their work to the required standards. Human resource functions are predominantly managed by the Compliance and Training Manager

2.8.7.5 *Service Contract Negotiations*

Our policy is to use Netcon for the majority of the network's operations, maintenance, renewal and upgrade work. All work is subject to a Service Level Agreement which is negotiated between ourselves and Netcon each year.

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

Specialist jobs, such as 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, are undertaken by outside contractors who would quote to a scope or specification, on a competitive basis.

Figure 2.5 Netcon is our preffered contractor.

3 Network Assets

3.1 Introduction

A major factor in whether we achieve our mission statement of 'commercial success in the delivery of energy' is the configuration, capacity and reliability of our network assets. The requirement to deliver energy means that our network must provide for the demands of energy users, while energy demand itself is a result of competing social, economic, political and environmental forces.

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

Chapter 5 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 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 over page.

Please note, the Hakataramea and high country bounding on Aviemore and Benmore lakes are part of Network Waitaki, while Cooneys and Canal road substations are missing from this diagram but shown on Figure 3.20 at page 78.

The three district councils, namely Mackenzie, Timaru, and Waimate district council, 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 below.

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%	-0.6%
Total	54,330	53,880	55,626	2.4%	0.14%

Table 3.1 above, shows that growth in 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.

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

Figure 3.1 Our area of supply

Timaru is the hub of South Canterbury connecting the road networks west, north and south. The city serves a central business area, main residential population, a range of industries and commercial businesses including two meat works, a container 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. Our largest customer, Fonterra (30 MW instantaneous maximum demand) operates a milk processing factory at Clandeboye and continues to expand their operation as well as 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 deployment providing intensive farming productivity.

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

The Waimate area is administered by the Waimate District Council 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.

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. Mackenzie District Council 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 in the Tekapo and Twizel destinations are predicted to increase, particularly in Twizel with plans for further irrigation development in the district and a new retail development in Tekapo Township planned for 2014.

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

The total energy consumed (measured in GWh) has been in the region of 700 to 800 GWh over the last 4 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 (measured in MW) is presently 126.5 MW[5]. Growth in AMD has been approximately 2.32% per year, over the last 16 years. Historical trends show that there was a burst of AMD growth from 2002 until 2004 and then a lull until 2006, and then another burst from 2007 until 2010, after which AMD has steadied.

3.2.1 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 planned 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

[5] As at February 2013.

water will have a significant impact on the economy and have a direct impact on the configuration of the network.

Irrigation load is a significant cause of summer peak loading at all GXP's except Timaru, Twizel and Tekapo A. However an increase in demand for irrigation is tempered by local environmental restrictions on water use and nitrogen application.

The port operations have been an important element in the local economy although of late Fonterra as well as some shipping companies prefer to use Port Lyttleton and port operations have been significantly reduced. However Holcim cement has recently proposed to use Port Timaru for movement of its bulk cement. How these changes of use at the port will impact on our economy is yet to be determined.

Winter peak demand occurs for Timaru and Tekapo A GXP's, however other areas such as Fairlie and Geraldine also have significant demands for load during the winter months where 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.

3.2.1.1 Large Consumers

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

Figure 3.2 Clandeboye dairy factory

Table 3.2 Top five large consumers

Fonterra Co-Operative Group Limited	
Location	Clandeboye 1, Milford
Dedicated Assets	One underground 33 kV cable circuit from Temuka GXP, plus one overhead 33 kV line circuit from Temuka GXP, 33/11 kV zone substation, including 2 x 20 MVA OLTC transformers and 15 x CB 11 kV switchboard, plus several 11/0.4 kV distribution substations with transformers and RMUs.
Impact on the Network	Considerable.
Location	Clandeboye 2, Milford
Dedicated Assets	One underground 33 kV cable circuit from Temuka GXP, plus one overhead 33 kV line circuit from Temuka GXP, 33/11 kV zone substation, including 2 x 25 MVA OLTC transformers and 12 x CB 11 kV switchboard, plus several 11/0.4 kV distribution substations with transformers and RMUs.
Impact on the Network	Considerable.
Location	Studholme
Dedicated Assets	13 x 11 kV RMUs 7 x 11/0.4 kV distribution transformers. One dedicated 11 kV 630 Amp CB and teed off AEL lines. Switch-room at Studholme GXP for all local feeders.
Impact on the Network	Significant, but transformers and switchgear could be reused over time elsewhere in the network.
Silver Fern Farms, Pareora	
Location	Pareora
Dedicated Assets	Two existing dedicated 11 kV CB feeders to consumer 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.

Alliance Smithfield	
Location	Smithfield, Timaru
Dedicated Assets	11 kV connection to consumer owned switchgear
Impact on the Network	Significant, but feeder capacity could be rescheduled within

3.2.2 Network Energy and Demand Characteristics

Key energy and demand figures for our seven GXP areas for the year ending 31 March 2013 are detailed at Table 3.3 below.

Table 3.3 GXP energy and maximum demand figures

GXP area	Asset Utilisation (GWh)	Max Demand (MW)	Load Factor (F=W/(Pmax.T))	Transpower Capacity Utilisation (Pmax/Ptxfr)	Long-term Growth Trend (based on 16 year historic)
Albury	8.808	4.180	0.24	84%	1.8%
Bell's Pond	22.012	7.026	0.36	35%	8.95%*
Studholme	58.797	11.12	0.60	51%	3.19%*
Tekapo	16.931	3.918	0.49	39%	3.34%
Temuka	273.313	52.006	0.60	51%	3.18%
Timaru	344.250	62.222	0.63	76%	0.7%
Twizel	12.583	2.828	0.51	7%	2.21%
Exported	-19.547				
Generation	33.167				
Total	**750.314**	**126.5**			**2.32%**

Note: that the individual GXP's MDs are not coincident with each other or the total system MD.

Inspection of the Timaru and Temuka GXP maximum demand trends appear to show that the maximum demands for these two GXP's have plateaued over the last 5 years.

Forecast growth in demand has maximum demand increasing to 129 MW in 2013–14 and to 145 MW in 2018–19, assuming a constant growth rate of 2.32% 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 Transpowers' GXP's. A brief summary is offered in this section for GXP's, zone substations, and sub-transmission assets more detail being found in Chapter 9. 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.

3.3.1.1 Historical Impact on the Network Configuration

Our network comprises two historically distinct lines businesses, the Timaru MED and the South Canterbury EPB, 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 Timaru GXP.
- The phase shift 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, upgrading of 11 kV lines and cables and introduction of additional, or upgraded, points of connection between the two networks.

3.3.2 Bulk Supply Configuration

Detailed information on Transpower GXP's is found at Chapter 9. A summary of this asset information is given in this section.

Figure 3.3 over page, shows the configuration of the GXP's from a transmission perspective. Table 3.4 summarises key GXP details.

Figure 3.3 Transpower GXP's

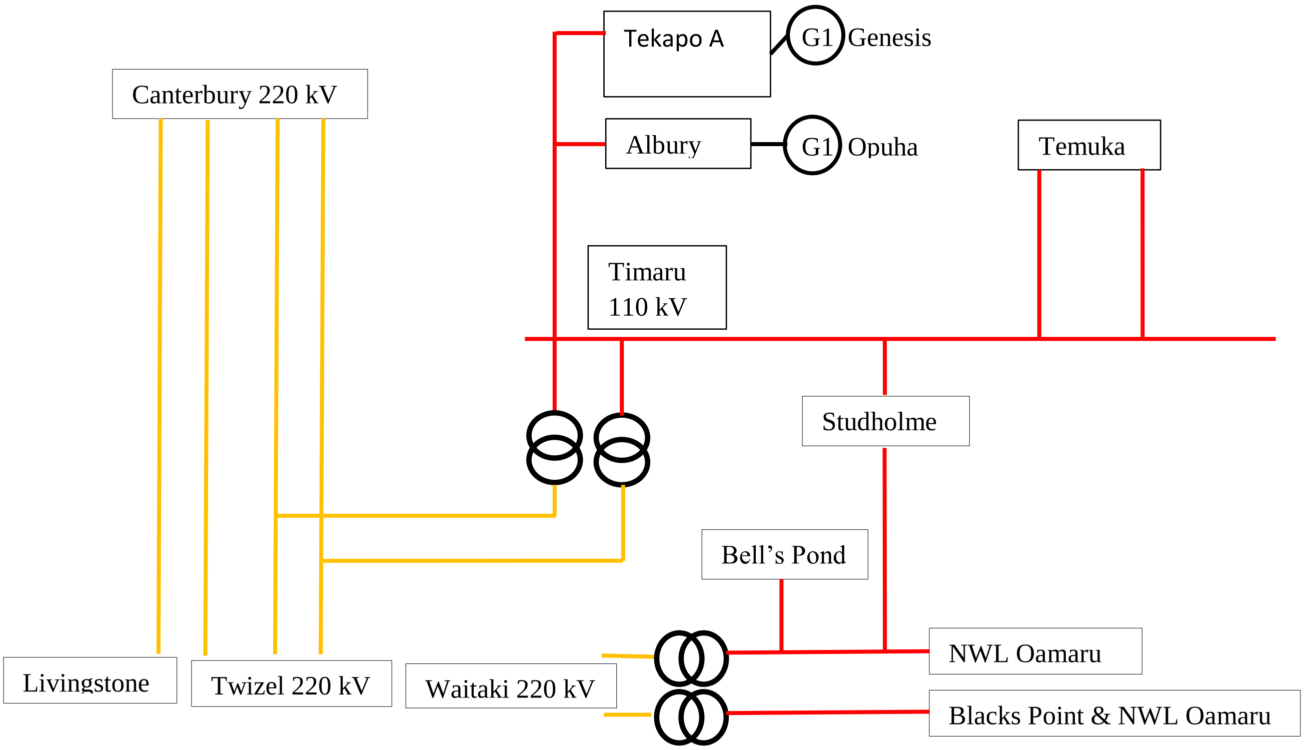


Table 3.4 GXP and related substation configuration as at 31 March 2013

GXP	GXP Voltage(s), Transmission	GXP supply Voltage to	GXP Capacity	GXP (N-1) Capacity	Demand	Embedded Generation (Opuha Dam)
Albury	110 kV	11 kV	6 MVA	0	4.2 MW	7.2 MW
Bell's Pond	110 kV	110 kV	20 MVA	0	7 MW	
Studholme	110 kV	11 kV	22 MVA	11 MVA	11.1 MW	
Tekapo	110 kV	33 kV	10 MVA	0	3.9 MW	
Temuka	110 kV	33 kV	120 MVA	60 MVA	52 MW	
Timaru	220 kV, 110 kV	11 kV	82 MVA	54 MVA	62.2 MW	
Twizel	220 kV	33 kV	40 MVA	20 MVA	2.8 MW	

3.3.3 Assets by Category

Our assets can be grouped into eight broad categories as listed below:

- Sub-transmission Circuits—33 kV (and 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).
- Distribution Lines and Cables—11 kV (and some 22 kV), and including pole mounted surge arrestors, and air-break type switches, fuses and links, line regulators, and capacitors.
- Distribution Substations—including 11/0.4 kV Transformers, RMUs, Reclosers.
- LV Reticulation Lines and Cables—including Link and Distribution Boxes: 400 V
- SCADA, Communications, and Ripple Load Control Plants, RTUs, protection, metering.
- 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 Chapter 9. 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 over page.

Table 3.5 Sub–transmission and zone substation configuration

GXP	Sub-transmission and Zone Substation Configuration
Albury	Albury 11/33 kV step-up substation, supplying single circuit 33 kV line to Fairlie, and from there the 33 kV line to the privately owned Opuha Power Station. Two 11 kV feeders
Bell's Pond	110/33/11 kV zone substation with three 11 kV feeders.
Studholme	11 kV indoor switch room, supplying at 11 kV the nearby Fonterra Studholme dairy factory, Waimate township, and the surrounding rural area.
Tekapo	Single 33 kV circuit to 33/11 kV Tekapo zone substation with four 11 kV feeders, and 33 kV line to Glentanner, Unwin Hut and other smaller 33/11 kV zone substations.
Temuka	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 Temuka zone substation with six 11 kV feeders. One 33 kV sub-transmission lines to Geraldine. One 33 kV sub-transmission lines to Rangitata. One 33 kV sub-transmission lines to Rangitata tapped off one of the Clandeboye 33 kV lines.
Timaru	Two circuits to Timaru 2 x 11/33 kV step-up Substation, supplying one single 33 kV line to Pleasant Point, and two predominantly single circuit and some double 33 kV lines to Pareora. Four 11 kV sub-transmission cable circuits to Grasmere St, which then split into a double circuit ring configuration to Hunt St and North St 11 kV zone substations. Two 11 kV sub-transmission cable circuits to North St (cables rated at 33 kV). Ten 11 kV feeders.
Twizel	Single 33 kV circuit to 33/11 kV Twizel Substation with four 11 kV feeders.

Table 3.6 over page 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)
Albury	2.37	0.00	N	2.5
Balmoral	0.00	0.00	N	0
Bell's Pond	7.03	0.00	N	3.5
Clandeboye 1	13.00	20.00	N-1	0
Clandeboye 2	12.00	25.00	N-1	0
Fairlie	2.37	0.00	N	0.5
Geraldine	6.52	0.00	N	4
Glentanner	0.20	0.00	N	0
Haldon Lilybank	0.30	0.00	N	0
Pareora	7.81	15.00	N-1	4
Pleasant Point	3.62	0.00	N	2.5
Rangitata	6.52	15.00	N-1	4
Studholme	11.12	11.00	N-1	3.5
Tekapo Village	3.98	0.00	N	0
Temuka	12.00	25.00	N-1	4
Timaru 11/33	12.25	25.00	N-1	0
Twizel Village	2.83	3.00	N-1	0
Unwin Hut	1.11	0.00	N	0

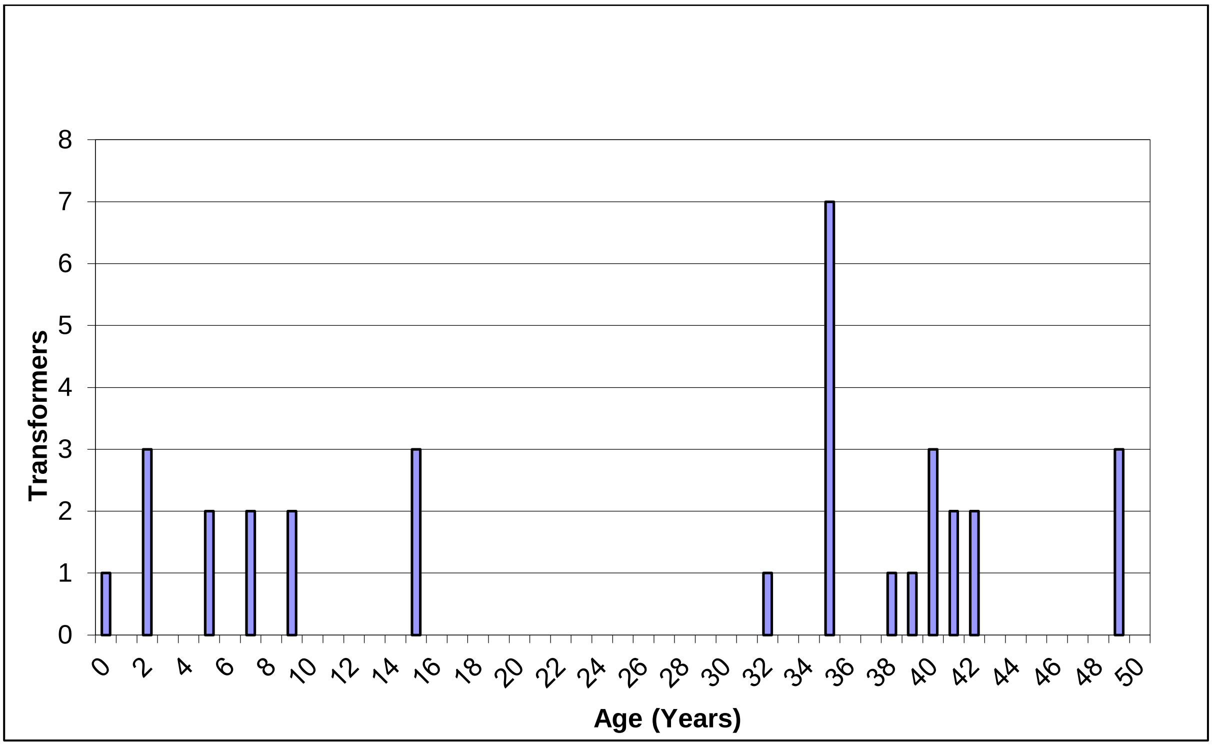
3.3.5 Major Zone Substation Assets

The following section describes the age and condition of substation transformers as well as 33 and 11 kV substation switchgear. For greater detail on these assets please refer to Chapter 9.

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 is provided in Figure 3.4 below, 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 transformers to the 1960's.

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 re-located.

The two 5/6.25 MVA transformers released from Pareora 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 reused at Fairlie and Tekapo 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 Rangitata in September 2012 requires its conservator to be enlarged due to an oil expansion contraction issue when fully loaded. This 1982 unit will be refurbished in 2014–15 at the same time that it has its conservator upgraded.

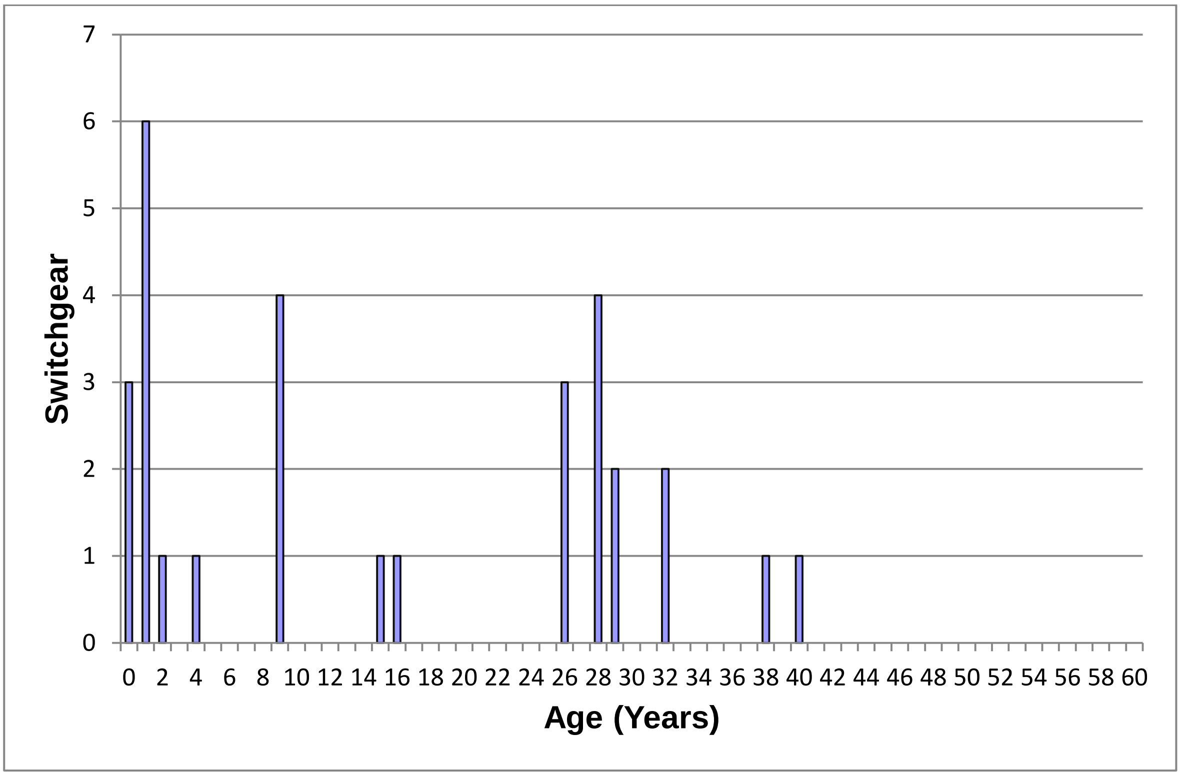
Four new 9/15 MVA transformer sets were purchased (3 in 2011), and installed and commissioned at Pareora and Rangitata in 2012.

Chapter 9 GXP, Substation and Sub–transmission Assets contains detailed information on the zone substation developments planned over the next few years.

3.3.5.1 Switchgear

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

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.

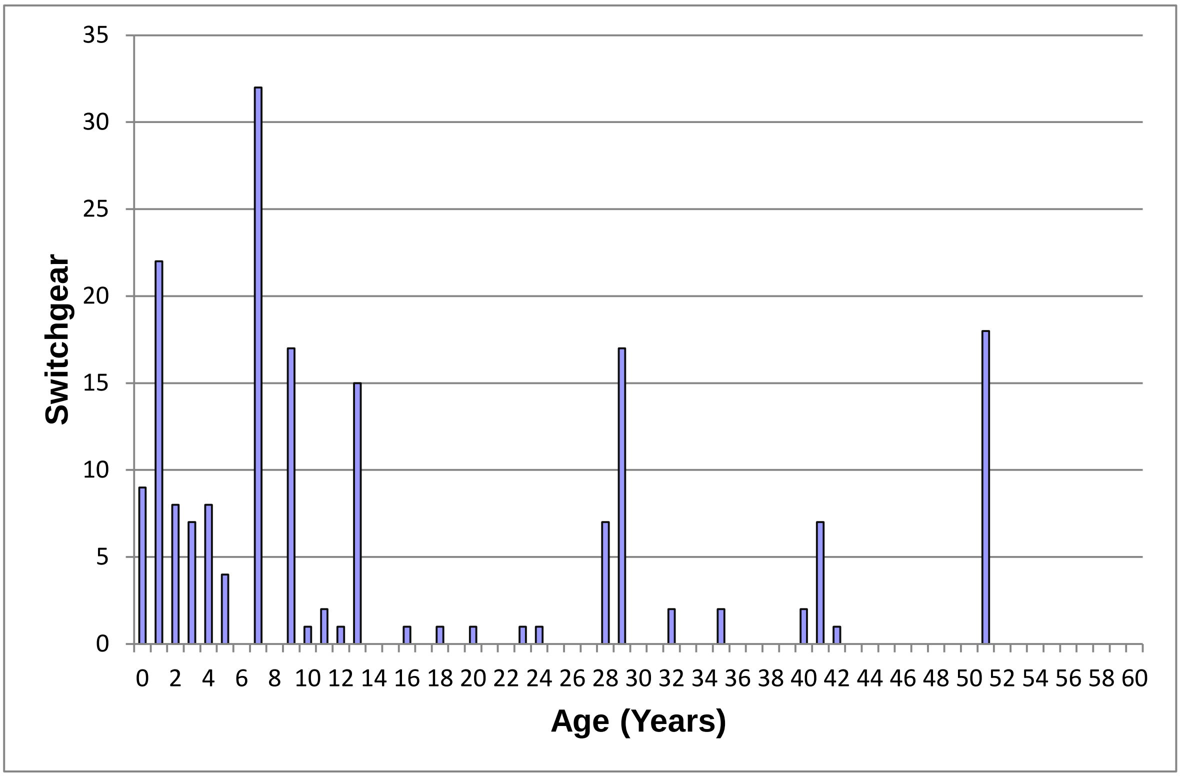
The six new 33 kV vacuum CBs commissioned at Pareora Sub in 2012 are indoor type with SF_6 insulated chambers. Two old vacuum/oil reclosers were decommissioned and one is available to be redeployed.

The two new 33 kV outdoor type SF_6 puffer type CBs commissioned at Rangitata 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 Rangitata Sub line, is an outdoor type.

Figure 3.6 below, gives an indication of the age of the indoor 11 kV circuit breakers on the high voltage 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 Grasmere (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, means that 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 seven years) and also have low maintenance requirements.

Most of the protection equipment installed on the network is 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 equipment is tested regularly; if the tests determine the equipment 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 equipment 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.

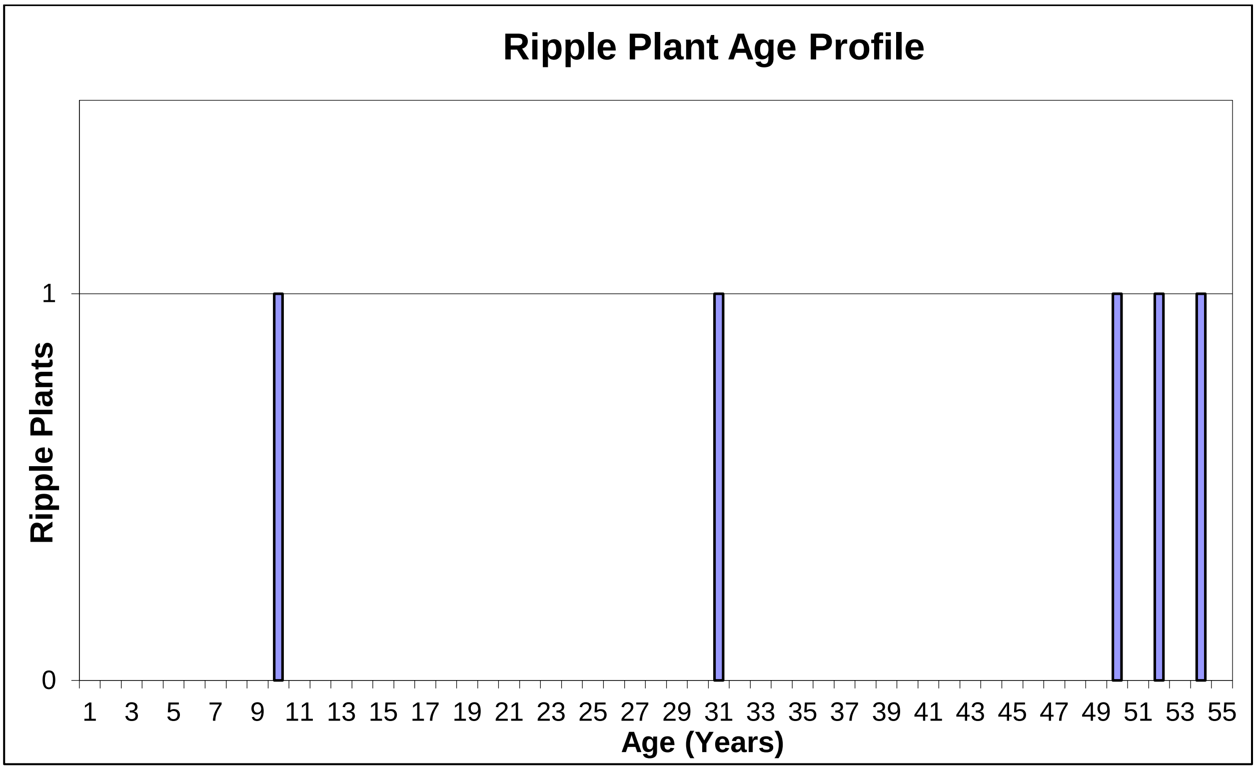
Substation buildings and grounds are regularly inspected, and maintenance is undertaken as and when necessary.

Figure 3.7 Transformer at Tekapo substation

3.3.6 Ripple Plant

The age profile of the current ripple injection plants is shown in Figure 3.8 below.

Figure 3.8 Ripple Plant age profile



A 10 year program to replace or decommission the old rotating ripple injection plants commenced in 2000. This was delayed 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 equipment.

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 over page.

To date we have standardised our 317 Hz static ripple plants, at Timaru, Studholme and Temuka. There are two 500 Hz rotary plants in service at Tekapo and Albury.

A shared ripple plant has been established at Twizel with Network Waitaki. Its frequency is akin to Network Waitaki's as they hold the larger population of ripple receivers. With the Twizel 33 kV bus being run split and Network Waitaki 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. This development will in time allow time clocks at Twizel to be replaced with more reliable ripple relays and security for load control in the Waitaki area.

Table 3.7 Ripple plant replacement programme

Item:	Year:	Programme:
1	2010–11	Reviewed rotating plant condition in Albury and Tekapo areas (completed)
2	2010–11	Reviewed local service security to Albury ripple plant converter (completed)
3	2010–11	The rating of Bell's Pond 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 Temuka ripple plant converter
5	2012–13	A review of the Timaru 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	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 Studholme to suit the lower impedance of the two new Transpower transformers (date revised)
8	2014–15	Build and Commission new plant at Albury, subject to Item 1 (installation date revised)
9	2014–15	Decommission rotating plant at Albury, subject to Item 10 which replaces with modern electronic plant (date revised).
10	2015–16	Build and Commission new plant at Tekapo (approximately 800 relays to change)
11	2015–16	Decommission rotating plant at Tekapo, subject to Item 9 which replaces with modern electronic plant (date revised).

Any modification to the Tekapo Village Substation from Tekapo A will need to consider the impact on the ripple plant.

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

In 2013, two new pad mount 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, both units located outside the ripple plant building.

The Studholme 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 equipment, 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 of the deployment of the smart meters is given to the Albury/fairly area and the Twizel area. This means that the existing timeclocks do not have to be replaced with ripple relays and thus provide a saving in capital expenditure.

3.3.7 Sub-transmission and Distribution Lines and Cables

The network consists of interconnected overhead circuits and underground cables operating at voltages of 110 kV, 33 kV, 22 kV, 11 kV, 6.6 kV and 400 V that distribute electricity from zone substations to rural and urban localities. The majority of rural networks are overhead using poles made from soft and hard woods as well a concrete. Urban networks are a mix of both underground cables and overhead lines.

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

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 (%)	84%	99%	90%	0%	48%
Underground (%):	16%	1%	10%	100%	52%
Total (circuit kms):	242.9	145.6	3,030.5	7.2	608.4

3.3.7.1 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.

3.3.7.2 33 kV Sub-transmission

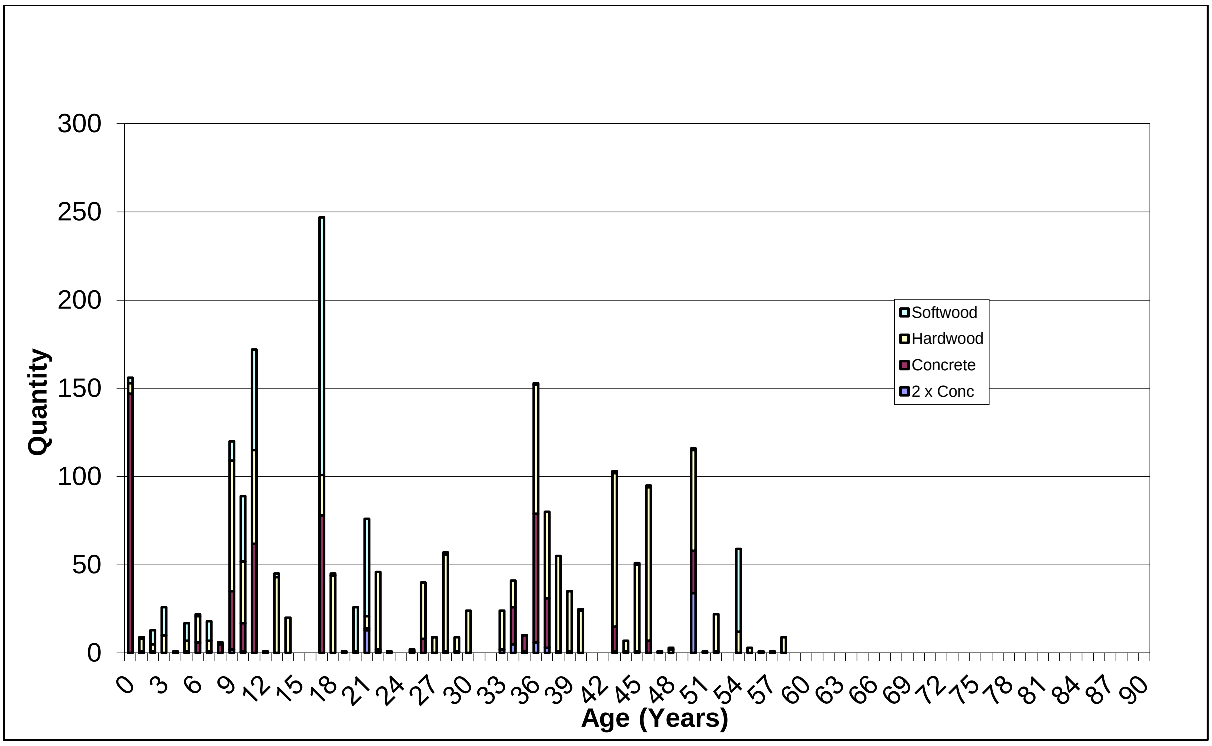
The majority of the 33 kV sub-transmission network was installed during the 1960's and 1980's to meet the growing demand in the rural network. The growth spike that occurred in 1996 resulted from the development of the 30 MVA dairy factory at Clandeboye. In 2004 a new 33 kV line was constructed to supply the Rangitata substation.

The two 33 kV lines to the Clandeboye Dairy Factory were thermally uprated to 30 MVA from 20 MVA during 2005. This was achieved by creating greater clearances through the replacement of alternate composite suspension insulator sets with porcelain post insulators as required. This approach provided an efficient and economical solution for the client and preserved the existing asset value. Subsequent inspection and testing of the remaining composite suspension insulators revealed that they were exhibiting signs of premature failure. These were also replaced with porcelain post insulators in 2011 which has now resulted in the whole line being re-insulated.

This line 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.

The age of 33kV sub-transmission poles is shown in Figure 3.9 below.

Figure 3.9 Sub-transmission Poles 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 below.

The two Timaru to Pareora substation overhead circuits are currently being refurbished. This project will span a period of five years and should be completed 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 line inspection priority

Location of line	Year of Construction	Route Length (km)
Timaru Sub to Pareora Sub #1	1979 and 1985	18
Timaru Sub to Pareora Sub #2	1963	16
Timaru Sub to Pleasant Point Sub	1977	16
Temuka Sub to Geraldine Sub	1966	17
Temuka Sub to Winchester Township	1979	5
Winchester Township to Rangitata Sub	2003	14
Temuka Sub to Clandeboye Sub	1997	10
Albury Sub to Fairlie Sub	1967	18
Opuha Dam to Fairlie Sub	1997	16
Tekapo Sub to Mt Cook Sub	between 1975 and 2001	50
Transpower Tekapo to Tekapo Sub	1991	1.5
Transpower Twizel to Twizel Sub	1968	1.5
Canal Rd CB to Rangitata Sub	2010	14

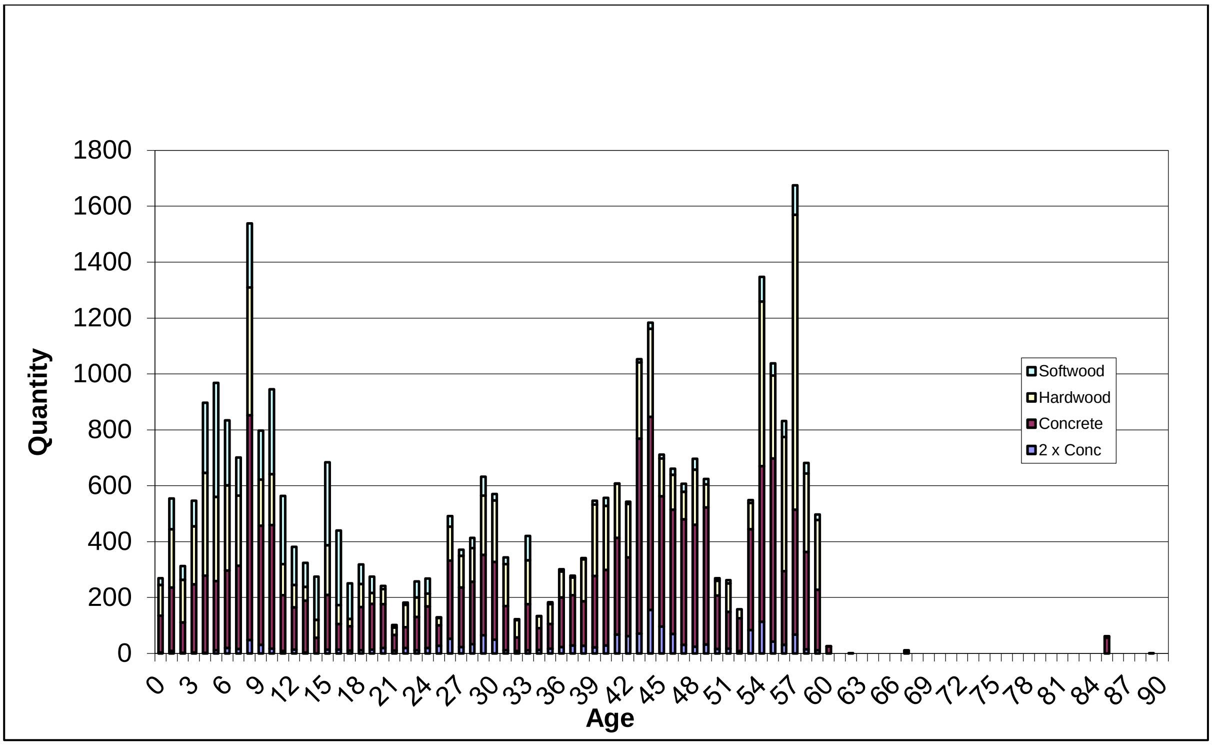
3.3.7.3 11 kV and 22 kV Distribution

The majority of the 11 kV and 22 kV overhead distribution systems were developed during the 1950's and 1970's with little development during the 1980's and early 1990's with load growth during this period being accommodated within the existing network capacity. Figure 2.1 over page, 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 3.10 Overhead poles distribution age profile



3.3.7.4 LV Distribution

All new low voltage reticulation within urban areas must be underground to comply with the various District Plans. Rural low voltage 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 is requested by the district council. Figure 3.11 over page, shows the impact of undergrounding of network assets.

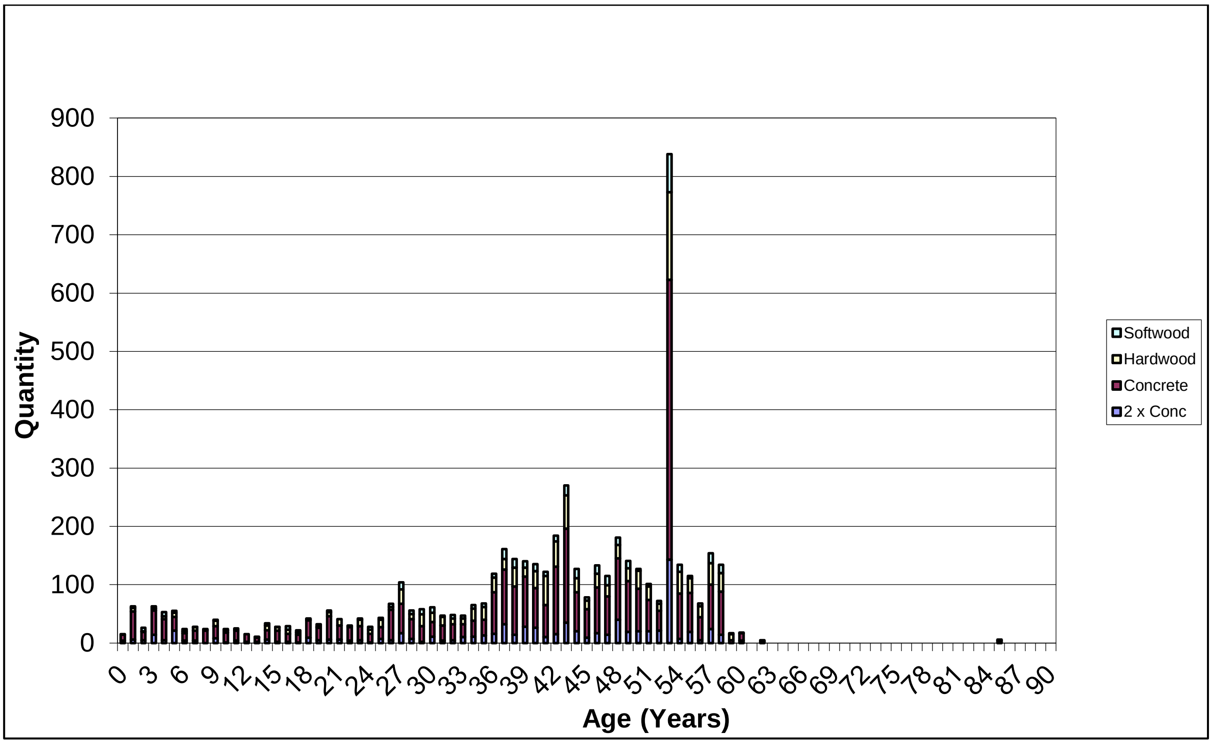
Where existing infrastructure has to be upgraded, the services will be undergrounded.

Existing low voltage 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 which may require the lines to be placed underground.

Figure 3.11 Undergrounding LV infrastructure at Domain Road

Figure 3.12 below, 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 3.12 LV overhead poles age profile



3.3.7.5 Poles and Crossarms

The network contains 43,085 poles as at February 2013. This number is derived from the GIS field capture project conducted in 2007 and subsequent works updates. The number and type of poles is summarised in Table 3.10 over page.

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 overlaid over the asset information in successive years to build up a complete electronic asset record. There are 24,589 concrete poles, 12,816 hardwood, and 5,395 softwood poles in our asset management system[6]

Table 3.10 Number, type of poles and estimated life span

Pole Type	Number of Poles	Estimated Life (Years)
Hardwood	12,816	40-50
Softwood	5,395	40-50
Concrete	24,589	50-80

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

With 40,143 poles there are some 77,483 crossarms allowing for combined high voltage/low voltage lines, double arms etc. As each crossarm has a life of 30 to 40 years the average replacement should be 1,900-2,600 crossarms each year based on expected age. Fortunately, cross arms remain in fair condition and therefore are only replaced when a condition assessment determines they are no longer capable of supporting design loads.

3.3.7.6 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 reused. 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 slowly expands, cracking the porcelain, 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 switch (ie 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 over the next 5 to 10 years either during maintenance or as required.

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.

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

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.

3.3.7.7 Conductors

Overhead conductors are either copper, steel or aluminium (ACSR, AAC, or AAAC). Early ACSR conductor used an ungreased galvanised steel core, and is 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 the following Table 3.11 below.

Table 3.11 Overhead circuit lengths

Construction Type	33 kV	22 kV	11 kV	6kV	400V	Comms
Three Phase	217.2	28.3	1881.8	0.0	228.4	n/a
Single Phase	0.0	115.9	859.5	0.0	62.7	n/a
Single Wire Earth Return	0.0	0.0	0.0	0.0	0.0	n/a

Conductor lifespan has been estimated between 60 and 100 years. However not all conductors perform uniformly, with some single strand and seven strand copper as well as smaller smooth bodied aluminium conductors, older than 50 years, exhibiting signs of reduced ultimate tensile strengths.

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 Studholme 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 AAC conductors appear to be in relatively good condition and do not require a high level of scrutiny. AAC conductors 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.

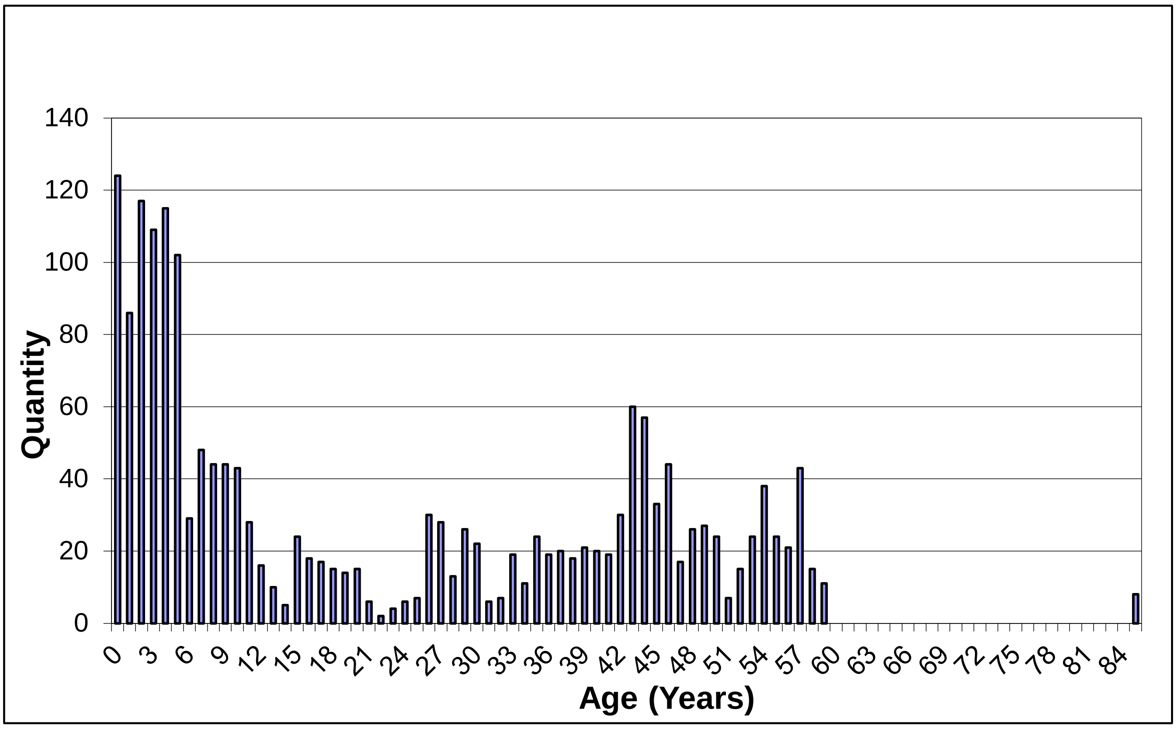
3.3.7.8 Pole Mounted Switchgear

Figure 3.13 over page, shows the age profile for our pole mounted switchgear. A significant proportion of these assets are 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), 11 kV Links through to 11 kV Reclosers and Sectionalisers. Transformer fuses are excluded from the age profile in Figure 3.14 at page 62 where in the past it was included.

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 3.13 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 up-rated with suitable load break equipment

To avoid Ferro resonance with 11 kV cable lengths over 50 m and/or transformers >1 MVA, each cable termination is protected with a disconnector (3-phase disconnect), surge arrestors, 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 isolation of 11 kV lines a less desirable situation.

Reclosers and Sectionalisers are being upgraded with the older style weight and chain devices replaced with modern 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 customers interrupted.

3.3.7.9 Voltage Support

Areas north of Temuka and including Rangitata have had significant re-conductoring and re-poling projects. As have the feeder sections from the Studholme substation to support load growth in the Otaio, Waimate, Morven, Waihaorunga, Springbank. Ikawai and Glenavy areas are fed by Bell's Pond.

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 re-conductoring 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.

3.3.7.10 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.

3.3.7.11 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 below.

Table 3.12 Underground circuit lengths

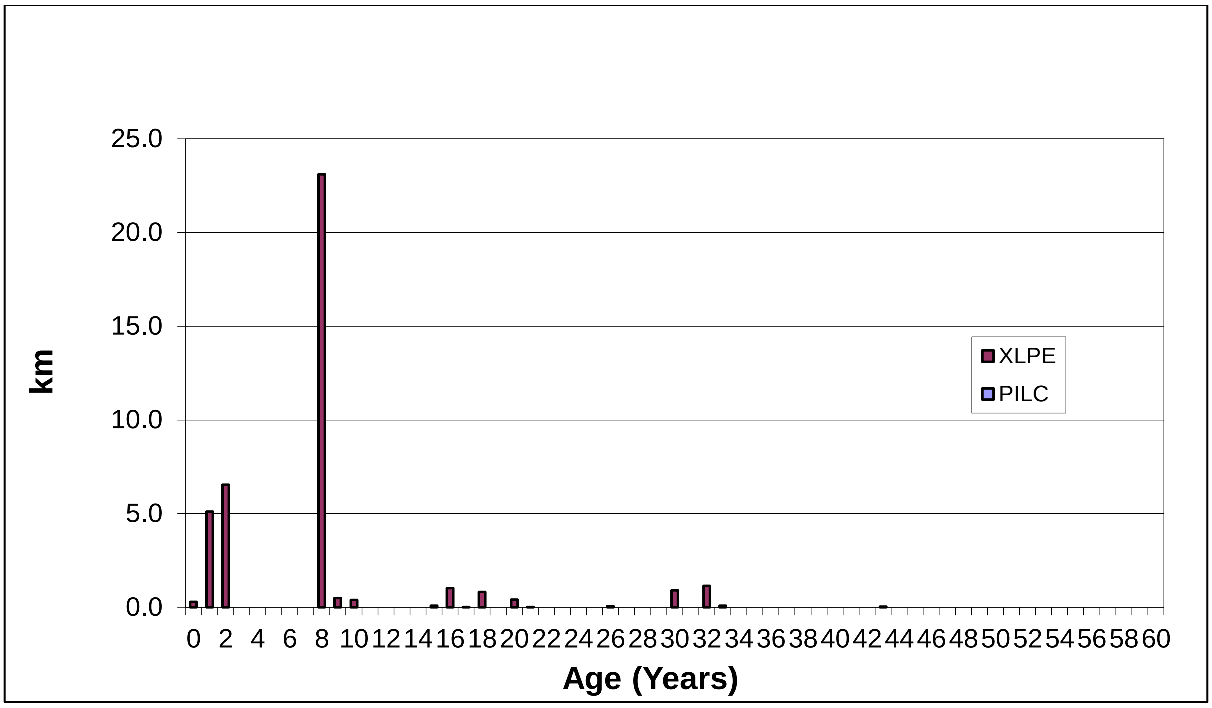
Construction Type	33 kV (km)	22 kV (km)	11 kV (km)	6.6 kV (km)	400 V (km)
Three Phase	50.0	0.9	273.5	0.0	312.6
Single Phase	0.0	0.5	43.1	0.0	7.3
Single Wire Earth Return	0.0	0.0	0.0	7.2	0.0

The age of underground 33 kV sub–transmission cable is shown in Figure 3.14 over page.

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.

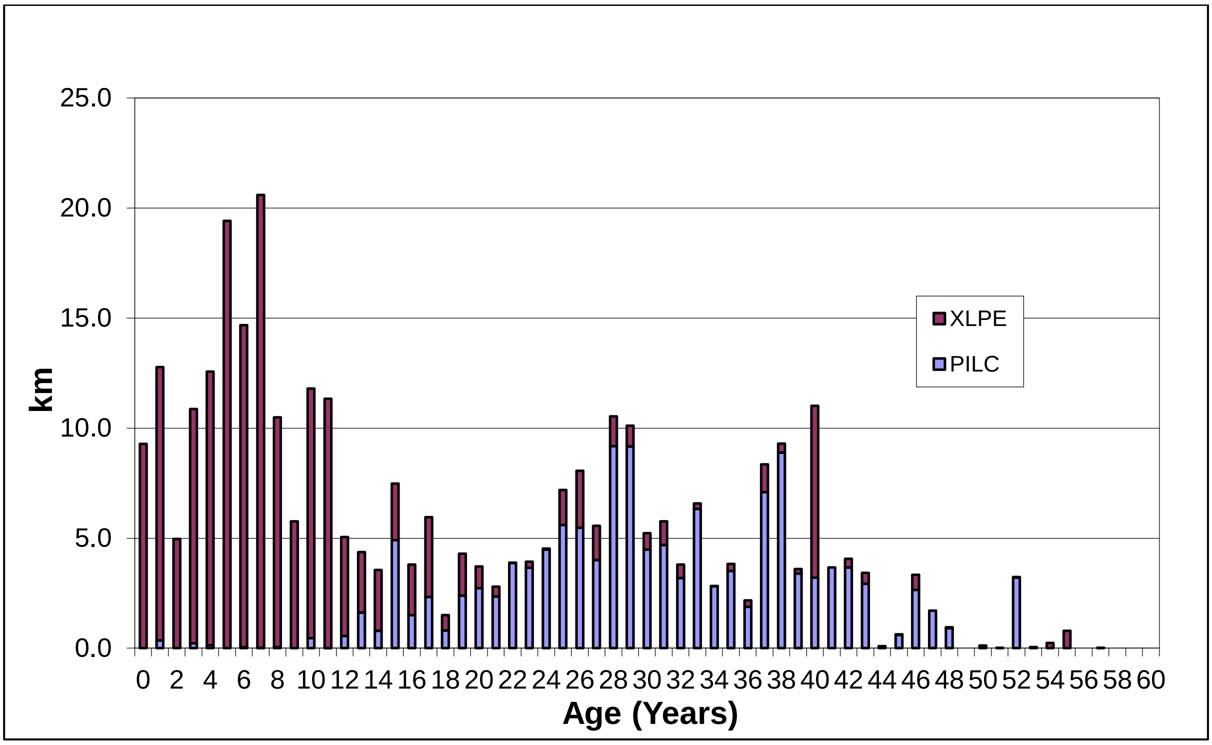
Partial discharge mapping was performed on the Clandeboye cables as part of Alpines preventative maintenance programme. All 33 kV cables on our network are less than 35 years old.

Figure 3.14 33 kV Sub–transmission cable age profile



The age of distribution cables is shown in Figure 3.15 below.

Figure 3.15 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 bi-annual 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 potential cable faults.

Figure 3.16 Mt Cook Village cable repairs

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's in its ODV handbook[7].

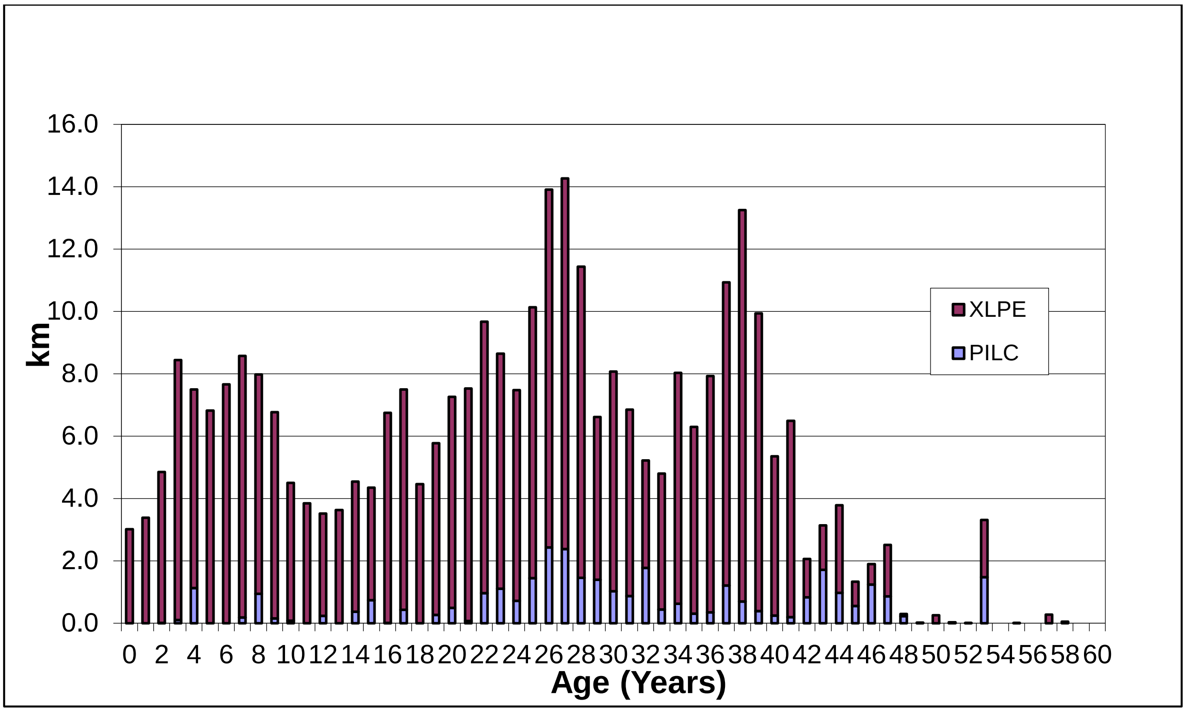
The ODV Handbook gives us a lifespan of approximately 70 years for PILC cables. We assume a life of roughly 40 years for XLPE cables installed prior to 1986 and a life of 50 years for those installed afterwards. This difference is due to advances in XLPE materials and construction made in 1986 that lead to XLPE cables having a significantly longer service life. It should be noted that these figures are pessimistic as the areas in which the bulk of our cables are laid are considerably dryer 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.

Very Low Frequency 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 low voltage cables is shown at Figure 3.17 over page.

[7] 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.

Figure 3.17 Low Voltage Cable Age Profile



The high voltage and low voltage cable networks include distribution boxes, oil switches and ring main units. Most of the system is relatively new, having been installed in the last twenty to forty years, compared to the estimated life of sixty to eighty years.

Fifty percent of the underground 11 kV distribution network was installed within the last 20 years. The majority of the older cables are of PILC construction, which has a 70 year life, while the more recently installed cables have been of XLPE construction which has an expected service life of 45 years.

A system has been implemented to log cable faults to build up a history of statistical data 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 have being experienced in 2012 due to the large number of contractors working in the Timaru area on the UFB project. 2013 has seen fewer 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 Timaru District Council. 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 central Timaru business district 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 expensive at more than $200 per metre. Maintenance over 2009–10 mainly involved replacement of LV joints and link boxes, both insitu 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 low voltage network are less than 35 years old, and subject to on-going sound performance and testing, their replacement is likely to be outside of the period covered by this plan.

However, during condition assessments in 2009–10, including thermographic inspections, a number of the in-pavement Lucy Box link and fuse boxes in the Timaru CBD have been found to have over heated 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 sweated or soldered connections to the underground LV cables, the maintenance solution may involve cable replacement ie 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.

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 to study the feasibility of developing a modern underground substation design with $_6$ or vacuum 11 kV switches with motor operation. The motorized switches would have 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 improved safety, but also would have allowed more efficient switching operations by removing the need for confined spaces procedures before operating the equipment

However, the cost of this option has proved to be prohibitive even allowing for the project being spread over twenty years.

Consequently, consideration is being given to the refurbishment of these underground substations being done 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.

3.3.8 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 50's, early 70's and 2000's.

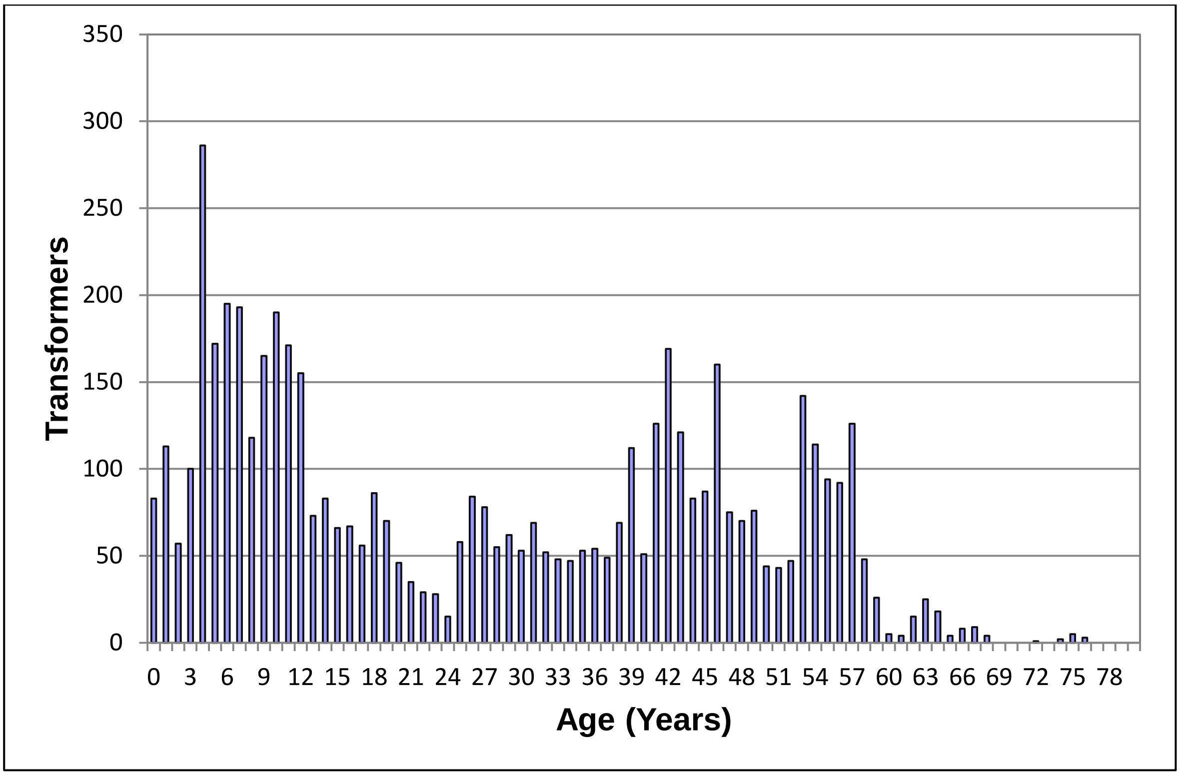
While the majority of our distribution transformers are less than 30 years old, some date back to more than 70 years. The age profiles of our distribution transformers can be seen in Figure 3.18 over page.

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 of asset condition basis rather than solely on age profile.

Figure 3.18 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 (eg rust) it is replaced and if appropriate then 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 835 transformers older than 50 years. However if no transformers are removed this will increase to 1,846 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 over page.

Table 3.13 Distribution transformers 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	68	25	63	144	79	37	63	7	**427**
Ground Mounted (Double End)	0	0	2	7	55	34	15	0	1	**114**
Ground Mounted (Single End)	2	1	0	0	1	0	0	0	0	**4**
Ground Mounted (T.E. Cubicle)	0	0	0	0	2	30	22	3	2	**59**
Mounted in U/G Sub	0	0	0	0	0	14	13	1	2	**30**
Mounted Indoors	0	0	1	2	4	14	7	6	14	**48**
Pole Mounted	2,663	897	649	356	147	27	1	0	0	**4,740**
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	4	6	2	10	1	4	**33**
Unknown Mounting Type	0	0	0	0	0	0	0	0	0	**0**
Total	**2,669**	**969**	**681**	**438**	**374**	**209**	**108**	**14**	**30**	**5,492**

3.3.8.1 Ground Mounted Distribution Substations

There are 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 low voltage and high voltage connections and fittings. The typical types of ground mounted transformers on our network are categorized as follows:

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

3.3.8.2 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 that are mostly no longer in service as substations.

The underground substations of the 1970 design are generally located just below pavement level 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.

A project was investigated which would have allowed the refurbishment of these underground distribution substations with new, non-oil insulated, remote surface operated motorized switchgear where the substation cannot be relocated above ground but when refurbishment is required. This would be a quite expensive option.

More recent thinking is along the lines of two 10-year stages, with stage one being replacement of the LV Statter switches with above ground HRC Fuse Rack Cubicles, and the second stage the replacement of the oil filled RMUs with above ground SF_6 RMUs, while retaining the transformers underground. Where possible this equipment would be sited on private property with a dedicated easement; otherwise they may need to be pavement mounted in the street reserve.

The condition of these substations and their equipment 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 twenty 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.

3.3.8.3 Surface Mounted Subs

Surface mounted substations in our 11 kV distribution network are of various sizes, designs and configurations, depending upon the era of installation, manufacturer and site conditions ie 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 (eg Padmount substation). They may include in the HV cabinet an 11 kV switch, such as an RMU (eg 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 1980's) 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 1970's, 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. 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.

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 equipment and for possible oil leaks (rare) from the transformer and/or HV switchgear.

3.3.9 Line Regulators, Capacitors and Rural Switches

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

This equipment includes:

- Voltage Regulators (to correct for varying voltage drop).
- Capacitors (to correct for 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, allows isolations on higher loaded feeders and at tie points).
- Disconnectors, (pole mounted non-load break switches – often called air break switches (ABSs)).
- 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 transformer that are prone to Ferro resonance problems).
- Surge (Lightning) Arrestors.

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

The rapid increase in irrigation and dairy related rural load in recent years has necessitated us installing 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 realised.

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

3.3.9.2 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 and may be used in association with one or more regulators.

3.3.9.3 Reclosers

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

Reclosers are sometimes used for line protection duty permit 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 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.

3.3.9.4 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. Which are capable of operation via a radio network to allow remote switching of the feeder to make 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.

3.3.9.5 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 type of switches in service of different makes and types.

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

3.3.9.6 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 to allow three phase breaking of connected but unloaded or very lightly loaded lines.

3.3.9.7 HV Fuse Links

We have a very large number of installed high voltage 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 sometimes require to be installed in series with a disconnector when a three phase break is required. Such as for a short cable spur to a transformer or where there is a motor that must not be single phased.

3.3.9.8 Surge (or Lightning) Arresters

These are often associated with particular items of equipment such as transformers, regulators, high voltage 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, from switching surges, or induced power frequency surges, etc.

The arrestors contain material that changes conductivity in the presence of an overvoltage to allow current to flow to earth to damp 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 arrestors need to be replaced.

3.3.10 LV Reticulation Lines, Cables, including Link and Distribution Boxes

Low voltage lines and cables distribute electricity from distribution sub stations to services. Low voltage 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. Low voltage 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 under ground, both in the country and in the town.

The relative cost of under-ground verses overhead depends upon 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 underground on an application basis. Accordingly, our AMP no longer includes forecast expenditure for overhead to underground conversions as was reported in prior AMPs.

3.3.10.1 LV Underground Cables

Low voltage 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, neutral screen Cu, XLPE insulated, with PVC sheath, complying to AS/NZS 4026.

3.3.10.2 Distribution Boxes (Boundary Boxes)

The connections between under-ground 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 since the first under-ground reticulation. These include concrete, painted electrogalved steel, galvanized steel, and plastic boxes.

3.3.10.3 Link Boxes

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

There are several models of link box in service, of different constructions and materials, similarly to the distribution boxes.

3.3.11 Protection Relays, SCADA and Communications Systems

Protection relays as the name suggests protect equipment from electrical faults by detecting over currents or over voltages or other out of limit conditions, and tripping 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.

3.3.11.1 SCADA

The SCADA (Supervisory Control and Data Acquisition) System enables remote control of connected substation equipment, and the acquisition of data from that equipment. The data describes the present state of the equipment, 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 and security alarms. The SCADA System also enables control of certain equipment, such as circuit breakers. It also records historical data, such as events and analogues, for future reference and analysis.

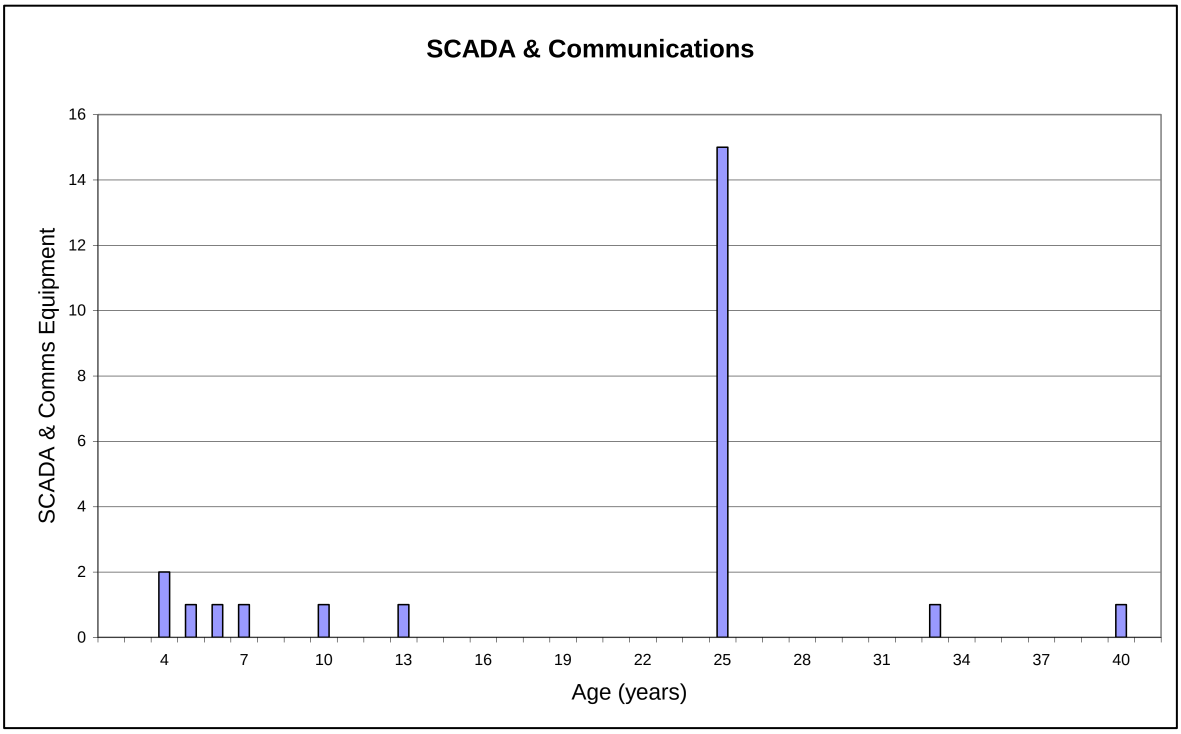
3.3.11.2 Voice radio

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 3.19 below, the voice radio repeaters and main radio shelf are due for replacement as the technology is becoming obsolete due to the age of the equipment which is now requiring more servicing to maintain transmit levels within the correct power regions.

Figure 3.19 SCADA and communications age profile



A report has been commissioned that outlines options for a suitable replacement radio platform which uses the next generation of technology. We engaged an external provider to complete an implementation plan for the upgrade of the communications network.

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.

3.3.11.3 SCADA Communications - Radio System

The company has a legacy SCADA communications system that comprises:

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

A Communications Upgrade Project, that includes for 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 – Studholme substations (Conitel).

- Washdyke – Mt Rollesby – Twizel and Tekapo substations (Conitel).
- Washdyke – Timaru substation (Conitel on landline).
- Washdyke – Grasmere/Hunt/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 RTU's and IED's.

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 resemble a network as illustrated in the following Figure 3.20 over page.

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 (Grasmere St, Hunt St and North St), the Timaru GXP, and the Washdyke Depot Control Room. It also includes a new fibre optic network between Temuka and Clandeboye No.1 and No.2 that links to the 5 GHz digital radio network at Temuka.

Only Studholme, Timaru Ripple, Twizel, Tekapo, and Fairlie Zone Subs are still using the legacy UHF/Conitel network. These subs will be upgraded in future years.

3.3.11.4 Load Control Ripple Injection Plant

We operate load control of energy storage devices (eg hot water cylinders) located at consumers premises via operation of ripple injection plants located at Timaru, Studholme, Temuka, Albury, Bell's Pond, and Tekapo. Details of the plants are contained in Chapter 9 GXP, Substation and Sub–transmission Assets.

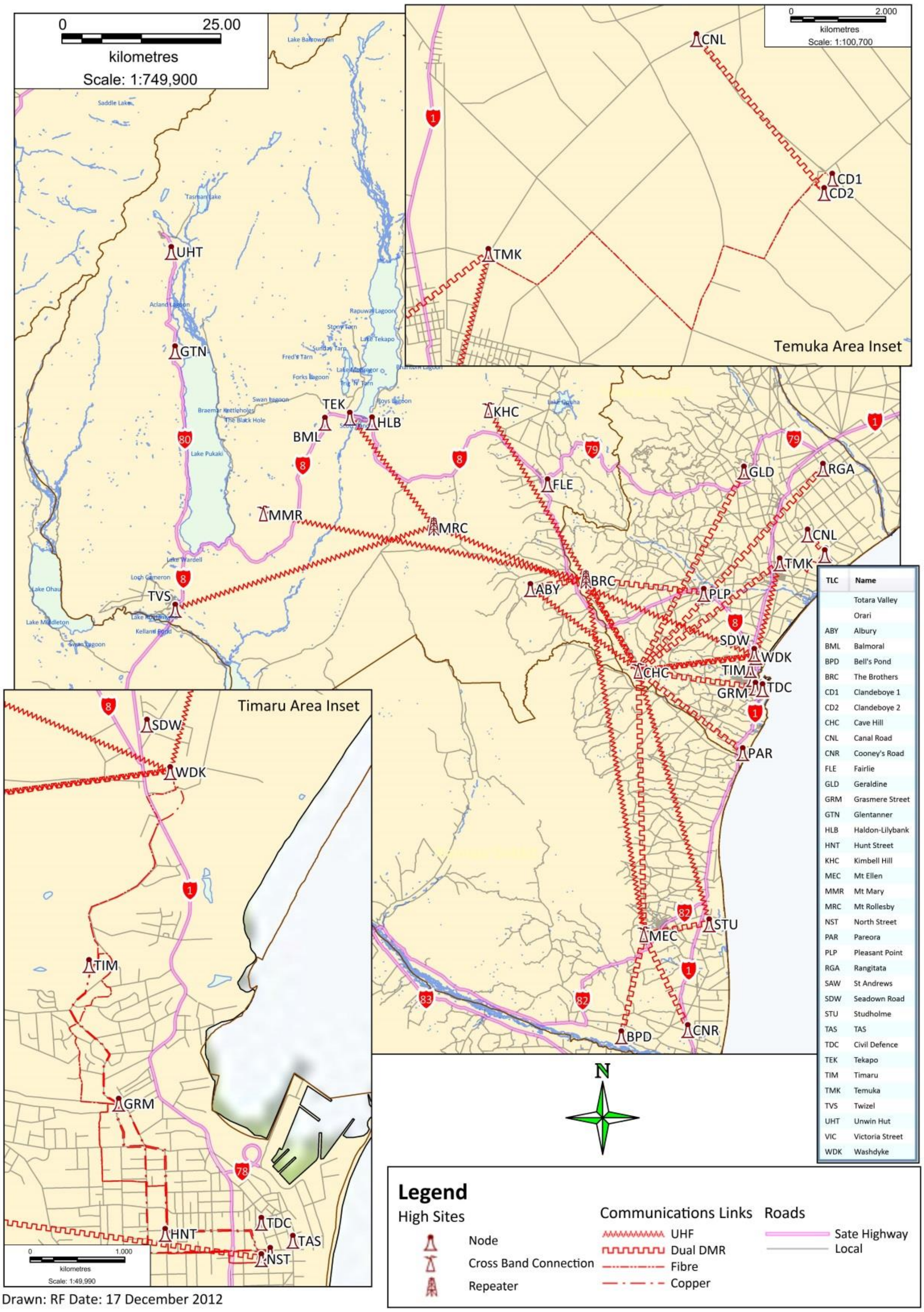
3.3.11.5 Protection Schemes

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

- electromechanical relays
- electronic relays
- numerical relays
- integrated protection and control devices (eg recloser controllers)
- The protection relays form part of protection schemes and systems that include equipment such as;
- tripping source, generally a battery
- instrument transformers (eg CTs, NCT, VTs, etc.)
- protection relays
- wiring looms
- trip coils in the circuit breaker/recloser

Figure 3.20 Data communications map

Alpine Energy Communications Map



Drawn: RF Date: 17 December 2012

- fuses
- auxiliary contacts
- terminal blocks.

The protection schemes and settings are designed to clear faults as quickly as practicable to protect life, equipment 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 (eg rural zone substation with small single transformer bank). While the more complex network arrangements with high fault levels have quite complex schemes (eg 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 equipment are being replaced with modern numeric relays and new associated equipment 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 replacement of the auxiliary equipment, as appropriate.

3.3.11.6 Meters and Load Control Relays at Consumer Premises

We have provided meters and relays at consumer's premises for electricity retailers as part of our current standard use of system agreement. From June 2013 we will become 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 a provision 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. As smart meters are rolled–out, we will be able to use our smart meters as a means of demand management and load control within our network. Thereby, we avoid the need to install more expensive load control equipment on 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.

3.3.12 Distributed Generation

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.

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. The rate of connection of such installations was initially very low with approximately one new installation per year since 2009. However, in 2012 the rate increased sharply with total annual new installations increasing to approximately a dozen for the 2012–13 year.

This sudden increase reflects significant reductions in price of PV arrays during 2012.

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 Tekapo Substation building. Our web site provides public access to this data.

3.3.13 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 Section 5.2.6 and 5.5.

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) on our assets, including the initial step of building assets (lines and substations). Some of these assets obviously need to deliver greater service levels than others.

For example our Grasmere St 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 Pleasant Point 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 the following issues to be considered:

- An intimate 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 to be clearly understood ie 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 to be recognised; for example, a 90 kW pump motor load will require a 200 kVA transformer that is only fifty percent loaded while running, but fully loaded on soft starting the pump motor. In some cases capacity can be staged through use of modular components.
- Recognition 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.
- Allowing 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 creates is 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 (ie 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 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-system assets such as motor vehicles, office equipment and furniture, etc. We own meters and ripple relay receivers and leases these to the retailers operating on our network. Metering assets are not covered in this AMP.

Further information of the configuration and ownership of assets at each GXP site is contained in Chapter 9 GXP, Substation and Sub–transmission Assets.

4 Performance Measures

4.1 Introduction

In this chapter we discuss our performance targets, explain how we set our performance targets, report how we have performed against those targets, and where appropriate we provide forecast 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 at Chapter 7.

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:

i) the CEO, Compliance & Training Manager, and the Health and Safety Committee conduct an annual audit of the Health and Safety Management Plan by

ii) 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
iii) managers conduct regular tours and audits covering the contents of the Health and Safety Management Plan
iv) 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 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 (ie 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.

$$\frac{\sum(Interrupted\ Consumers\ X\ \ Interruption\ Duration)}{Total\ \ Number\ \ of\ \ Connected\ \ Consumers}$$

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 over page.

$$\frac{\sum(Number\ \ of\ \ Interrupted\ \ Consumers)}{Total\ \ Number\ \ of\ \ Connected\ \ Consumers}$$

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 is without supply during the year. CAIDI is derived using the formula below.

$$\frac{\sum(Number\ of\ \ Interrupted\ \ Consumers\ X\ \ Interruption\ \ Duration)}{\sum(Number\ of\ \ Interrupted\ \ Consumers)}$$

CAIDI provides the consumer with the average time that they were without electricity supply during the year duration. 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 target is set using the five year average performance for the period 1 April 2004 to 31 March 2009. The commission do 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 commission uses measures of performance against targets to signal whether there has been a 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 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 customer surveys have historically supported this assumption.

4.4.3 Performance against the targets

Table 4.1 below, shows our un–normalised performance against target between 1 April 2004 and 31 March 2013, and forecast performance for the current year[8] and the year ending 31 March 2015[9].

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[10]	Performance	Variance[11]	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	848.76	+684.54	1.99	+0.3	426.51

4.4.3.1 Normalisation of reliability performance

In its setting of the performance measures the 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 (for example, earthquakes). To account for this variability the Commission use the IEEE 2.5 Beta method[12] to 'normalise' the annual performance.

We have had our performance normalised at two of the last 10 years annual review dates. In 2006 we had a major snow storm which contributed over 900 system minutes to our total reported

[8] Current year performance need be forecast as the actual performance (1 April 2013 to 31 March 2014) is not finalised at the time that the AMP is published ie 31 March 2014.
[9] Forecast performance for both SAID and SAIFI for the 2014/15 year are based on the average performance over the two years (ie 2011/12 and 2012/13) that we did not exceed the quality standard.
[10] 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.
[11] The SAIFI target from 1 April 2005 was 1.10 interruptions per annum, and 1 April 2010 is 1.69 interruptions per annum.
[12] The IEEE 2.5 Beta Method is based on a EDBs 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 is replaced by the boundary value.

SAIDI on 1,113.93 system minutes. The normalised performance was 207.75, which exceeded the target SAIDI level by 119.55 minutes. In 2010 we again experienced severe weather events which saw our normalised performance reduce from 332.36 system minutes to 145.58, which exceeded the target SAIDI by 57.38 SAIDI minutes. Unfortunately, due to the severe storms experienced during 2013 we will exceed our performance measures during the current year. However, we expect our reliability to come under performance targets for the coming year (ie 2014/15).

4.4.3.2 The impact on reliability of the storms of 2013

Heavy rain and snow storms in June followed by high winds in July and then more wind in September saw lines brought down, predominately by trees falling across our lines. We estimate the impact of the storms on us has been 89 system days in total. Responding to the storms also affects our subsidiary contractor Netcon. The impact for Netcon was two-fold, firstly Netcon respond during the event and secondly, the follow-up remedial and tidy up work to reinstate our network to its normal state.

Photographs of the type of damage that we received during the server weather events of 2013 can be found at Figure 4.1 below.

Figure 4.1 Photographs of storm related damage on our network

4.4.3.3 Vegetation management remains an on-going 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 are 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 meters by the wind.

To educate land owners of the impact of trees on our network, in conjunction with Electricity Ashburton Networks, Mainpower, and Orion, we published the public safety message *Reduce the risk of power cuts* in local newspapers at Figure 4.2 below.

Figure 4.2 Reduce the risk of power cuts

The message informed land owners that the power outages experienced following September 2013 severe wind storm were primarily due to trees and branches coming into contact with overhead lines and poles. As trees on private land are the responsibility of the land owner, we need their help to reduce the impact of future storms on the network. The message goes on to explain how land owners can help to reduce the risk of power cuts by managing vegetation near power lines through considered and safe tree maintenance.

4.4.3.4 Performance under the targeted control regime

During the commission's assessment of performance against the quality standard under the default price-quality path (DPP) at the 2009/10 assessment period it raised concerns about our performance against both the SAIDI and SAIFI targets. For the 2009/10 assessment period, our SAIDI result of 332 minutes was nearly three times our allowable SAIDI limit and our SAIFI result of 2.2 interruptions was nearly double our allowable SAIFI level.

The commission reviewed our reliability performance trend over the period 2004/05 to 2009/10 to establish whether our performance trend was indicative of a sustained deterioration of the network. The review concluded that there was no evidence of sustained deterioration on the network, and made eleven observations about our asset management practices.

To take advantage of the opportunity given to us by the commission we undertook to address our asset management short falls. And to report to the commission the progress on our actions for each year for three years, at the same time that we provide our annual compliance against the DPP.

We are now in our third and final reporting year. We have come a long way since the commission's review and have made a number of advancements using its observations as a platform for change. This year we:

i) Started Stage 2 of our business process mapping project whereby we review and look for continuous improvement on our existing mapped processes.
ii) Completed our organisational restructure and created two new teams; IT Services and Regulatory and Pricing.
iii) Expanded our existing engineering resources to bring the team a more strategic focus.

More details on our progress can be found in our annual progress reports on our website[13].

4.4.3.5 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 below, provides the breakdown of our actual performance against target for planned and unplanned interruptions on our network for the year ending 31 March 2013.

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

[13] A copy of the commission's review and our progress reports for the 2011/12 and 2012/13 years can be found on our web site at http://www.alpineenergy.co.nz/disclosures. The third and final report as at 31 March 2014 will be available on our website mid June 2014.

Table 4.2 Performance summary – planned and unplanned SAIDI and SAIFI

Measure	Target 2012/13	Actual 2012/13
Planned SAIDI – Class B	52	38.32
Unplanned SAIDI – Class C	112.00	109.95
Planned SAIFI – Class B	0.30	0.15
Unplanned SAIFI – Class C	1.39	1.14
33 kV faults per 100 km	-	0.82
22 kV faults per 100 km	-	5.49
11 kV faults per 100 km	-	4.62

During 2012/13 we performed well within the set targets for both planned and unplanned outages. However, for the current year we have forecast that we will perform within the targets for planned outages, but will exceed the set targets for unplanned outages by some seven times the SAIDI target and one and half times the SAIFI target.

4.4.4 Causes of unplanned interruptions

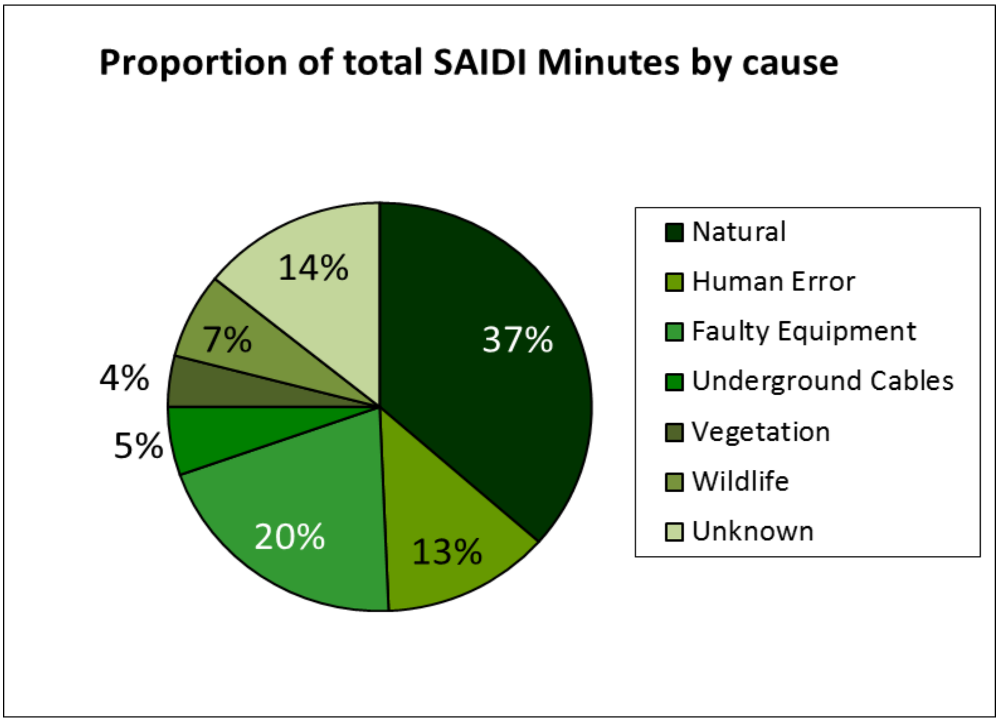
The breakdown contribution of unplanned outages to our overall SAIDI performance is shown in Table 4.3 below.

Table 4.3 Summary of unplanned outages' contribution to SAIDI minutes

Number of unplanned Outages by cause (in SAIDI minutes)	
Cause of Fault	**Actual 2012/13**
Natural	35:00
Human Error	17:47
Faulty Equipment	27:50
Underground Cables	07:58
Vegetation	01:36
Wildlife	07:27
Broken Conductors	0:00
Other	0:00
Unknown	12:19
Total	**109:57**

The percentage contribution of all factors affecting the SAIDI minutes lost for unplanned outages for 2012/13 is shown in Figure 4.3 below.

Figure 4.3 Proportion of total SAIDI by cause of interruption



In 2012/13 After outages caused by natural causes at 37%, faulty equipment was next largest cause of outages at 20%. To explain the 20% we look at our worst performing feeders to determine if there is a trend that needs addressing, which are discussed at section 4.4.6 below.

4.4.5 Ten-year reliability targets

Table 4.4 below, 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 4.4 Primary consumer service levels

Measure	Year Ending 31 March									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SAIDI	164	157	157	157	157	157	151	151	151	151
SAIFI	1.69	1.62	1.62	1.62	162	1.62	1.55	1.55	1.55	1.55

The revised SAIDI levels are based upon the actual performance YTD and the expected improvements to SAIDIs from 2016-17 onwards as the automation of pole mounted reclosers and other network improvements begin to take effect. The benefits of these network improvements are expected to increase the efficiency of switching for planned outages and reduce the response time associated with switching for faults.

The revised SAIFI targets to a constant level are to allow savings from reduced frequency of outages from faults to permit more planned outages to improve access to the network for required 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 2013 with respect to outages are detailed at Table 4.5 below.

Table 4.5 The ten worst performing feeders by outage

Feeder	No. of events	SAIDI (in system minutes)	SAIFI (no. of interruptions)
Levels	10	03:13	0.06
Normanby	10	05:45	0.09
Waitohi	10	02:00	0.03
Woodbury	8	04:42	0.06
St Andrews	7	01:12	0.01
Milford	6	01:14	0.01
Mt Studholme	6	00:23	0.00
Winchester	6	03:55	0.06
Fairlie Rural	5	01:13	0.01
Morven	5	00:47	0.003

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 2013 with respect SAIDI minutes lost and causes are detailed at Table 4.6 over page.

The worse performing feeder by SAIDI minutes was Geraldine 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 worse performing feeder with regards to SAIDI minutes at 5.45 SAIDI minutes.

Table 4.6 The ten worst performing sun-transmission/feeders by SAIDI minutes

Feeder	No. of outages	SAIDI (in system minutes)	SAIFI (no. of interruptions)
Geraldine TS	3	09:30	0.13
Geraldine Sub 33kV	1	08:54	0.08
Waimate	2	08:11	0.06

Feeder	No. of outages	SAIDI (in system minutes)	SAIFI (no. of interruptions)
Tekapo Village Sub (33kV)	1	06:28	0.02
Fairlie F309 (33kV)	1	06:16	0.03
Normanby	10	05:45	0.09
Temuka East	2	05:04	0.06
Woodbury	8	04:42	0.06
Speechley	3	04:15	0.03
Winchester	6	03:55	0.06

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:

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

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 grid exit point 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 commission requires us to report our loss ratio each year as part of the information disclosure requirements. The definition used by the 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 include 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:

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

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

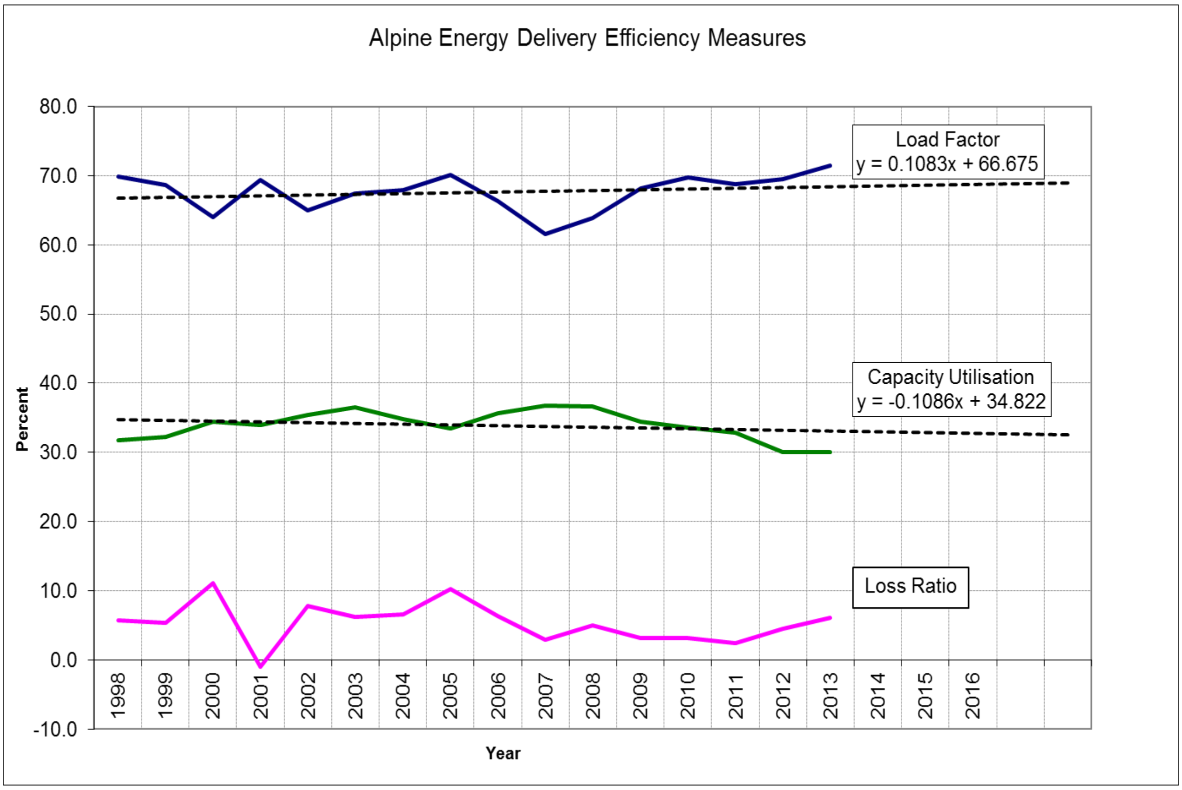
The actual and projected energy delivery efficiencies are listed Table 4.7 below.

Table 4.7 Projected energy delivery efficiencies

Measure	2013	2014	2015	2016	2017
Load Factor	68.3	68.4	68.5	68.6	66.7
Loss Ratio	4.2	4.0	3.9	3.7	3.5
Capacity Utilisation	33.2	33.1	33.0	32.9	32.8

Figure 4.4 over page, shows how our energy delivery efficiency measures we have tracked between 1998 and 2013.

Figure 4.4 Delivery efficiency measures trend



4.5 Service levels

We recognise that the performance measures of SAIDI and SAIFI are rather academic and that 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 4.8 below, shows the number of outages consumers might broadly expect in any given year by broad geographical areas.

Table 4.8 Expected service by location

General Location	Sustained Outages	Momentary Outages
Fonterra Clandeboye	1 outage of 2 hours every 5 years	1 outage every 2 years
Smithfield, PPCS, McCain Foods, DB Breweries	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
Washdyke and Port, including Polar Cold, Coolpak, 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

General Location	Sustained Outages	Momentary Outages
Waimate, Temuka, Pleasant Point, Fairlie, Geraldine, Tekapo and Twizel urban areas, including NZ Insulators, Canterbury Woolscourers, South Canterbury Byproducts, and Fonterra Studholme.	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 Hotels, and Hermitage 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 2012, divided consumers into three groups based on maximum demand. These groups were the top 25 consumers, all of whom were surveyed, our top 26 to 125 consumers, 30 of who were randomly selected and our mass market consumers where 30 were randomly selected.

Survey results showed that consumer preference for service levels fall into three distinct classes:

- Primary service levels—comprising continuity of supply (ie keeping the lights on or SAIFI) and restoration of supply (getting the lights back on or SAIDI).
- Secondary service levels—comprising absence of flicker and timely shutdown notices.
- Tertiary service levels—comprising activities such as answering the phone quickly, processing new connection applications and providing technical advice.

4.5.1.1 Continuity of supply

Continuity of supply is a fixed assets issue which is not always easily or inexpensively addressed. Consumers in all three market segments surveyed strongly indicated a preference for paying about the same price to receive about the same level of reliability.

Notification of interruptions to supply can be process driven, which keeps costs relatively low. Our larger consumers identified, at our 2012 customer survey, that the timely notification of unplanned outages was an area that we needed to improve. Notification is important to consumers as advising them as soon as is practicable of the likely restoration time allows large consumers to put into action the appropriate contingency plan.

During 2013 we install an automated notification system supported by Avalanche (TVD). TVD provides Operations Management including Trouble Call, Operations, Work Management and Wireless data solutions to utilities.

4.5.1.2 Timely shutdown notices and no flicker

Our consumers ranked timely shutdown notices and no flicker [14] as secondary service levels to continuity of supply and restoration. Industrial consumers, in our 2012 survey, put no flicker before timely shutdown notices and domestic consumers were spread in their opinion on these two aspects of electricity supply.

Absence of flicker

Flicker occurs where a voltage drop is caused by a momentary transient by the changing load current of consumer equipment connected to the network. Flicker is a visible, for example, by the change in brightness of a lamp. Flicker may affect sensitive electronic equipment such as industrial processes that are reliant on constant electrical power. Eliminating or even reducing flicker is a significant task on our network as our network is largely overhead and we have long lines in windy and snow-prone areas.

Our 2012 consumer survey indicated that:

- flicker tends to be more noticeable than problematic
- most consumers have a relatively poor understanding of the causes of power flicker, especially the impact of their own and other consumers' equipment and of trees and animals
- while consumers are very accepting of unplanned interruptions caused by storms or vehicles hitting poles, they are not so accepting of flicker even though the causes can be similar.

Timely Shutdown Notices

The timely notification of planned interruptions is largely a process driven and is something that can be easily and relatively inexpensively improved on. As a standard we provide consumers with five days written notice of a planned interruption (the commission require only 24 hours' notice), including an alternative shutdown day to allow for weather related stoppages.

We work with large consumers to schedule shutdowns during their quiet periods, ensure that shutdown notices are correctly addressed and confirm the shutdown 30 minutes ahead so consumers can initiate controlled shutdown procedures.

Table 4.9 below, shows that we expect to meet all of our shutdown notification times at any given year.

[14] As in flickering of lights (part power).

Table 4.9 Our performance targets against shutdown notification times

Service Level		Year Ending 31/3/14	Year Ending 31/3/15	Year Ending 31/3/16
Planned Shutdown Notices	Number of planned shutdowns for which we fail to give at least 4 working days' notice.	Nil	Nil	Nil
	Number of planned shutdowns for which we fail to accommodate large consumers production schedules.	Nil	Nil	Nil
	Number of incorrectly addressed shutdown notices.	Nil	Nil	Nil
	Number of occasions for which we fail to give large consumers 30 minute confirmation of shutdown.	Nil	Nil	Nil
	Number of planned shutdowns which fail to proceed without sound operational reasons.	Nil	Nil	Nil

We are aware of the inconvenience that interruptions cause our consumers, even if it is a planned shutdown. We consider notification and working with consumers, especially large consumers with production schedules fundamental to our agreed services levels. While it is possible that we would fail to meet at least one of the above in a given year we do not consider that it is acceptable that we do accordingly we will take all reasonable steps to ensure that at a minimum we always meet these targets.

Electrical Interference

Under certain operational conditions our assets can interfere with phone wires, railway signalling, consumers' plant, and the correct operation of our own network. The following codes impose service levels on us to mitigate electrical interference:

- NZECP36:1993 Harmonic levels
- IEC 61000: Electromagnetic Compatibility
- Electricity (Safety) Regulations 2010.

There are instances where consumers' equipment can operate in a manner that interferes with the network For example, plant with variable speed drives (VSD's) used to a large extent to drive irrigation pumps. VSD's inject unwanted harmonic currents into the network which results in harmonic voltages due to the network impedance. We manage this phenomenon through our Network Harmonic Standard in an effort to protect other consumers' equipment from this power quality issue. In extreme cases we will isolate a consumers connection from the network.

4.5.1.3 Answering the phone and processing applications

At the 2012 consumer survey consumers said that answering the phone quickly, processing new connection applications or providing technical advice was of least importance. We refer to these service levels as being tertiary. Table 4.10 below, shows the tertiary consumer service levels we expect to achieve over the next 3 years.

Table 4.10 Tertiary consumer service levels

Type of Service	Service Requirement	Year Ending 31/3/14	Year Ending 31/3/15	Year Ending 31/3/16
Answering phone	Within set time frames	Not considered	Not considered	Not considered
New Connection	Advise requirements within 10 Business Days and connect on agreed day if all requirements have been met	90%	90%	90%
Written response or estimates for new or additional Supplies	Reply within 10 Business Days	90%	90%	90%

The processing of applications is largely process driven and relatively inexpensive to improve. We recently completed stage 1 of our business process mapping; stage 2 will involve the review of all of our current processes to identify the opportunity for continuous improvement. We would expect processes like the processing of new connection applications to improve as a direct result of having business process maps.

4.5.2 Improving consumer service levels

We strive to improve our levels of service to our consumer's year-on-year. The consumers survey indicated to us that our consumers' biggest wants are also the most expensive and difficult to deliver whilst their lesser wants are much easier to deliver. Unfortunately, there is not a direct trade-off of simple improvements in tertiary service levels such as answering the phone faster whilst allowing primary service levels such as continuity and restoration to languish. Accordingly, improvements in our service standards are measured by considering the cost benefits of making any given improvement.

4.6 Financial performance

Our financial performance for the year ended 31 March 2013, the most recent disclosures, is shown in Table 4.11 below.

Table 4.11 Financial performance

Parameter	Target ('$000)	Actual ('$000)	Variance	
			('$000)	As a %
Lines charge revenue	38,490	38,873	+383	+1
Operational expenditure	17,070	28,858	+11,788	+69
Capital expenditure	15,391	12,301	-3,090	-20

4.6.1 Lines charge revenue

Target revenue for 2013 was $38.5m our total billed line charge revenue was $38.9 million. This is a variance of $383k (or 1%), which is not considered to be material.

4.6.2 Actual vs forecast expenditure

4.6.2.1 Operating expenditure

Table 4.12 below, shows the variance between our actual and budgeted operating expenditure for the period ended 31 March 2013.

Table 4.12 Variance in our operating expenditure as at 31 March 2013

Operating expenditure category	Target ('$000)	Actual ('$000)	Variance ('$000)	Variance As a %
Service interruptions and emergencies	1,127	1,208	+81	+7
Vegetation management	103	95	-8	-8
Routine and corrective maintenance and inspection	2,475	2,322	-153	-6
Asset replacement and renewal	1,539	378	-1,161	-75
Expenditure on network assets	*5,245*	*4,003*	*-1,242*	*-24*
System operation and network support	5,695	4,997	-698	-12
Business support	4,451	3,301	-1,150	-26
Expenditure on non-network assets	*10,146*	*8,298*	*-1,848*	*-18*
Total operational expenditure	**15,391**	**12,301**	**-3,090**	**-20**

We underspent for operating expenditure over the period by 20%. Target operating expenditure was $15.4 million whereas actual expenditure was $12.3 million. This result is largely attributable to an under spend in IT Services.

In 2013 we created a new IT Services group to drive our significant IT programme. We were unable to secure all our budgeted resources before the end of the period.

4.6.2.2 Capital expenditure

Table 4.13 over page, shows the variance between our actual and budgeted capital expenditure for the period ended 31 March 2013.

Table 4.13 Variance in our capital expenditure as at 31 March 2013

Capital expenditure category	Target ('$000)	Actual ('$000)	Variance ('$000)	Variance As a %
Consumer connection	2,250	6,975	+4,725	+210
System growth	6,339	17,056	+10,717	+169
Asset replacement and renewal	5,516	2,097	-3,419	-62
Asset relocations	0	2	+2	+100
Reliability, safety and environment	2,325	2,280	-45	-2
Expenditure on network assets	*16,430*	*28,411*	*+11,981*	*+73*
Expenditure on non-network assets	*640*	*447*	*-193*	*-30*
Total capital expenditure	**17,070**	**28,858**	**11,788**	**+69**

Our capital expenditure exceeded budget for the period by 69%. Target capital expenditure was $17.1 million whereas actual was $28.9 million. The variance is attributable to us closing more than 400 jobs from previous periods during the year, and the completion of several large projects that were commissioned during the period.

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.
- Due to the diminishing returns of each dollar spent on reliability improvements.
- Consumer specific request, and agreement to pay for, a particular service level (eg 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

As responsible network providers we must be able to provide the capacity requirements of consumers and generators both within and outside the existing network. However because additional capacity requires time to plan and build we must be able to forecast future load requirements in order to provide capacity for our consumers when it is needed.

We must also plan to meet other requirements that may stem from our stakeholders, including, regulations and the need to maintain industry standards and good practice.

Planning therefore happens at a number of levels depending on what is required from, or driving network development. At the highest or strategic level planning is concerned with the load growth requirements of GXP's and major zone substations. The mid or tactical level plans for the impact of drivers on minor zone substations, HV lines and cables and distribution assets, while the operational level is concerned with low voltage lines and cables and customer metering and load control assets.

This chapter describes our planning process and identifies the key drivers of load growth before discussing load projections for each GXP and related substations as well as options and plans to meet these forecasted demands. Renewal drivers are discussed in Chapter 0.

5.2 The Planning Process

5.2.1 Introduction to the Planning Process, Criteria and Assumptions

This section summarises the planning process to meet network requirements. This process is summarised in Figure 5.2 and is structured so that each process is explained in the same order as it occurs in the diagram.

This summary also includes as part of the planning process the planning assumptions and criteria that we use to identify preferred options.

5.2.2 Planning Approaches

Our network planning is primarily driven by expected network load growth and regulatory requirements for security of supply. Network planning is also driven by any issue which causes a breach of industry standards or good practice. All planning is done with the aim of meeting our mission statement and corporate goals and objectives as outlined in section 2.3 Mission Statement, Goals and Objectivesat page 13.

Planning and load growth forecasting is conducted by our senior engineering team who utilise extensive industry knowledge. Their approaches to planning at strategic, tactical and operational levels can be seen in Table 5.1 over page.

Table 5.1 Planning approaches

Attribute	Strategic	Tactical	Operational
Asset description	Assets within GXP. Sub-transmission lines and cables. Major zone substation assets. Load control injection plant. Central SCADA and telemetry. Distribution configuration eg decision to upgrade to 33 kV sub-trans and a zone substation.	Minor zone substation assets. All individual distribution lines (11 kV). All distribution line hardware. All on-network telemetry and SCADA components. All distribution transformers and associated switches. All HV consumer connections.	All 400 V lines and cables. All 400 V consumer connections. All consumer metering and load control assets. However, in the context of large scale renewal or upgrades, even LV planning should be elevated to tactical and strategic, as appropriate (eg recabling of a significant LV circuit in the Timaru CBD).
Number of consumers supplied	Anywhere from 500 upwards.	Anywhere from 1 to about 500.	Anywhere from 1 to about 50.
Impact on balance sheet and asset valuation	Individual impact is low. Aggregate impact is moderate.	Individual impact is moderate. Aggregate impact is significant.	Individual impact is low. Aggregate impact is moderate.
Degree of specificity in plans	Likely to be included in very specific terms, probably accompanied by an extensive narrative.	Likely to be included in specific terms, and accompanied by a paragraph or two.	Likely to be included in broad terms, with maybe a sentence describing each inclusion.
Level of approval required	Approved in principal in annual business plan. Individual approval by board and possibly shareholders.	Approved in principle in annual business plan. Individual approval by Chief Executive.	Approved in principal in annual business plan. Individual approval by Network Manager.
Characteristics of analysis	Tends to use one-off models and analyses involving a significant number of parameters and extensive sensitivity analysis	Tend to use established models with some depth, a moderate range of parameters and possibly one or two sensitivity scenarios.	Tends to use established models based on a few significant parameters that can often be embodied in a rule of thumb.

A further guide for planning is the investment strategy matrix seen in Figure 5.1 below. This broadly defines the nature and level of investment and the level of investment risk implicit in different circumstances of growth rates and location of growth.

Figure 5.1 Investment strategy matrix

Location of demand growth		
Outside of existing network footprint	**Quadrant 3** • CapEx will be dominated by new assets that require both extension and possibly up-sizing. • Likely to absorb lots of cash – may need capital funding. • Easily diverts attention away from legacy assets. • Likely to result in low capacity utilisation unless modular construction can be adopted. • May have high stranding risk.	**Quadrant 4** • CapEx will be dominated by new assets that require both extension and possibly up-sizing. • Likely to absorb lots of cash – may need capital funding. • Easily diverts attention away from legacy assets. • Need to confirm regulatory treatment of growth. • May have a high commercial risk profile if a single customer is involved.
Within existing network footprint	**Quadrant 1** • CapEx will be dominated by renewals (driven by condition). • Easy to manage by advancing or deferring straightforward CapEx projects. • Possibility of stranding if demand contracts.	**Quadrant 2** • CapEx will be dominated by up-sizing rather than renewal (assets become too small rather than worn out). • Regulatory treatment of additional revenue arising from volume thru' put as well as additional connections may be difficult. • Likely to involve tactical upgrades of many assets
Prevailing load growth	Lo	Hi

Examples of how the planning process utilises the investment strategy matrix when accounting for different drivers are as follows:

- Large industrial loads such as a new dairy factory which involves firstly extension and then usually up-sizing sit in Quadrant 4 which has desirable investment characteristics. This mode of investment does however carry the risk that if demand growth doesn't occur as planned, stranding can occur and the investment slips into Quadrant 3 which has less desirable investment characteristics.
- In-fill Dairy conversions and irrigation development involve extensions and often up-sizing - Quadrant 2 and 4 - but due to the lumpy nature of constructing line assets these may fall into Quadrant 3 which carries some risk of stranding or delayed recovery of investment.
- Tightening clean air policies that prompted an upsurge in heat pumps and electric vehicles in urban areas would primarily require urban network up-sizing which fits mainly in Quadrant 2 which has reasonably desirable investment characteristics.
- Residential subdivisions around urban residential areas tend to have large up-front capital costs but recovery of costs through line charges often lags well behind and depends on the timeframe from section sale to house building. The size of the subdivision will dictate whether it falls in Quadrant 1 or 3, neither of which has particularly desirable investment characteristics. Hence some form of developer contribution is almost certain to be expected.

- Quadrant 1 in the Timaru GXP supplying the CBD area because of the lower level of load growth due to the prevailing existing domestic residential area, and what little growth there is generally occurs within or very close to the existing footprint.
- Quadrant 4 in the Timaru GXP area supplying north into the Washdyke expanding industrial area which continues to experience new loads of 1 -2 MW capacity being established.
- Areas like Twizel and Tekapo have potential to move from Quadrant 1 to Quadrant 3 during the period of the plan as subdivision development creates opportunity for larger developments outside the existing network area. There is also irrigation potential in the rural zones beyond the residential development areas.

The planning process will be further enhanced by our Network Prioritisation Development model. For more information please refer to section 5.8 at page.155.

5.2.2.1 The Planning Unit

For incremental planning of the network at large, we have adopted the 11 kV feeder as the fundamental planning unit which typically represents one or a number of the following combinations of consumer connections:

- An aggregation of up to 1250 urban domestic consumer connections.
- An aggregation of up to 200 urban commercial consumer connections.
- An aggregation of up to 20 or 30 urban light industrial consumer connections.
- A single large industrial customer especially if that customer is likely to create a lot of harmonics or flicker.

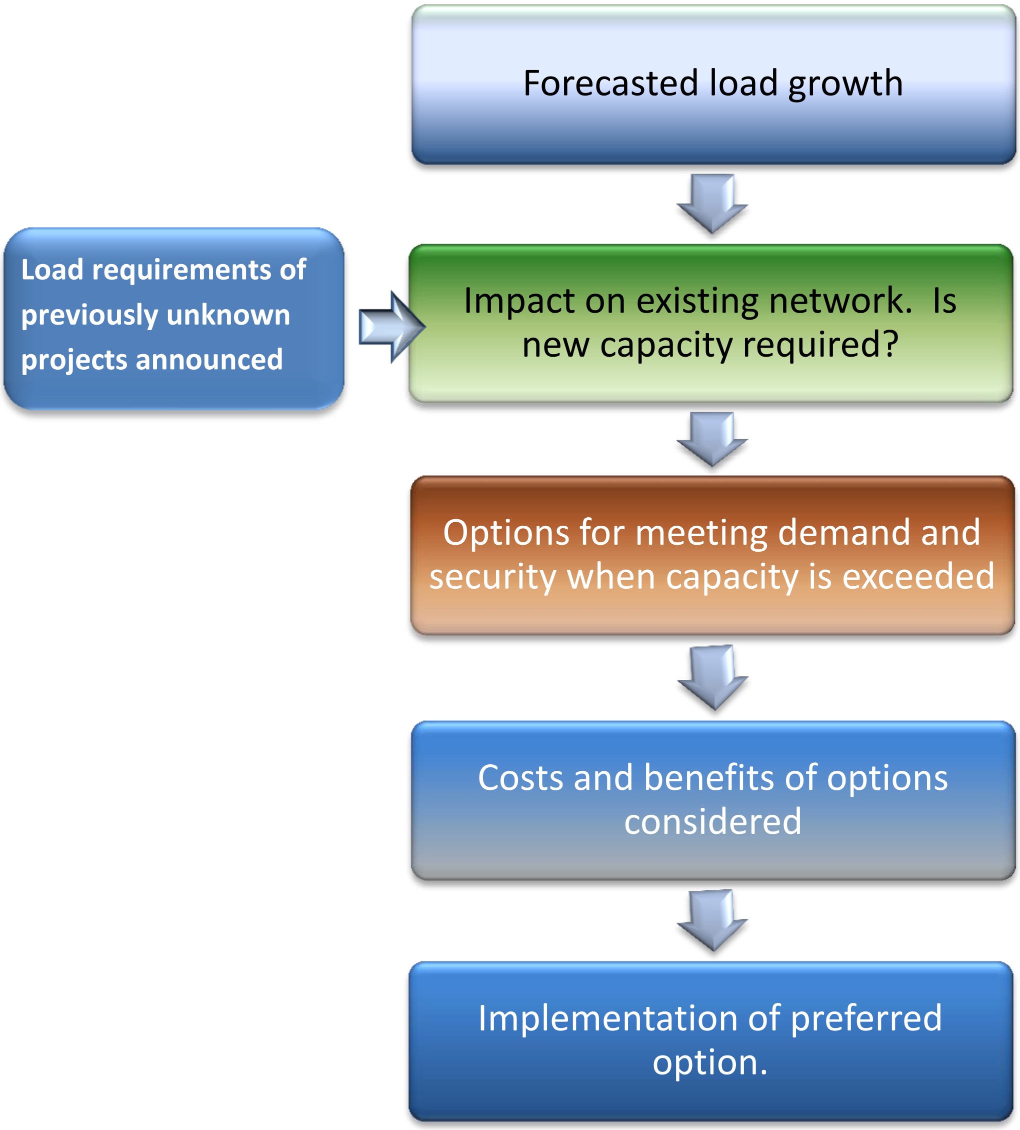
Physically this planning unit will be based around the lines or cables emanating from an 11 kV substation circuit breaker.

For single loads of 1 MW or more (ie beyond what might be considered incremental) our planning principles and methods still apply, but in the context of building new (possibly dedicated) assets at 11 kV or possibly even 33 kV.

5.2.3 Overview of the Planning Process

At the strategic level, load growth is forecasted for each GXP based on information sourced from Transpower, major industrials, other consumers, environmental regulation and any other area which may help us to accurately forecast the future load requirements for each GXP in our network. Our planning process is shown in Figure 5.2 below.

Figure 5.2 The planning process



Once all known and forecasted loads have been established, the impact of future load on the network is then assessed to determine the effect on existing assets, whether new capacity is required and if so what options are available to us to meet capacity requirements. Of importance too is the recognition of existing capacity constraints and their impact on limiting the range of options available.

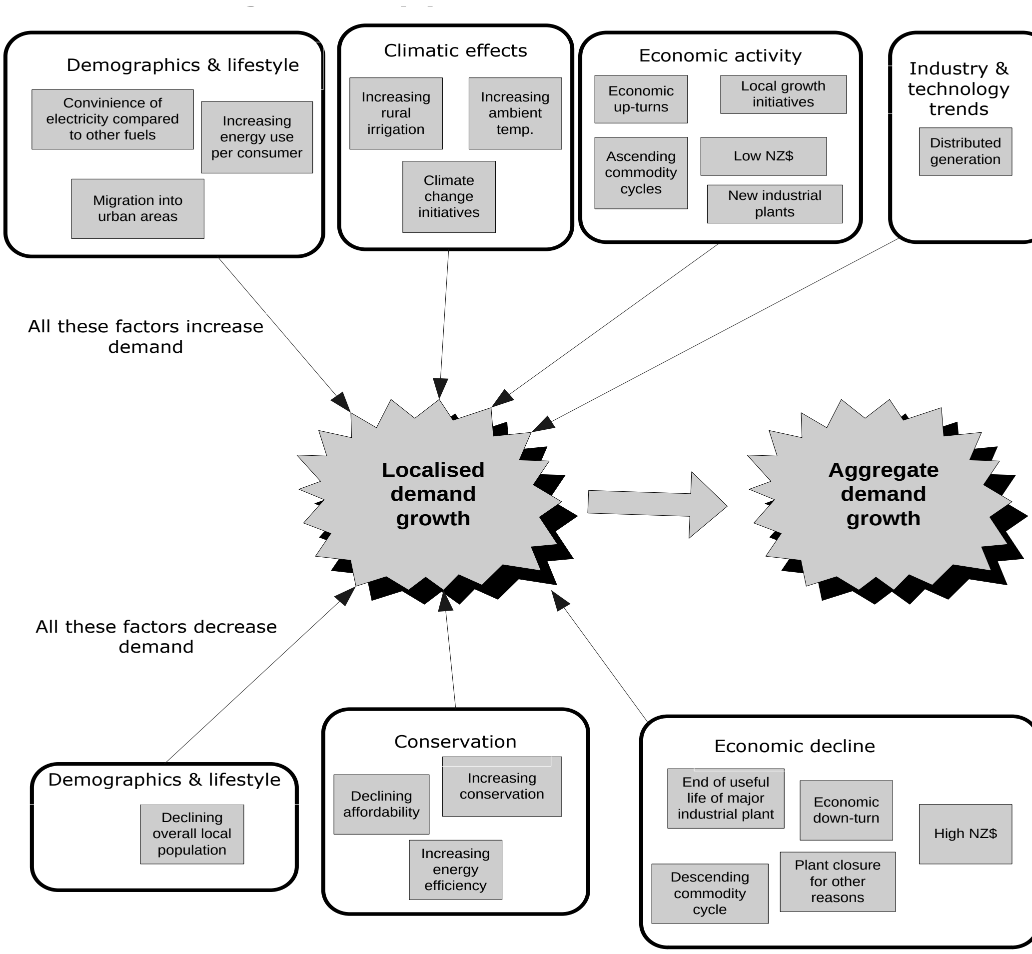
Cost benefit analysis is then applied to determine a hierarchy of options with the preferred option implemented.

5.2.4 Forecasting Load Growth

Demand forecasting requires an understanding of the series of drivers behind consumer's decisions to invest and request connection to the electricity network.

Drivers impacting on consumer's demand for load are seen in Figure 5.3 below.

Figure 5.3 Drivers of demand



Demand forecasting in the residential areas is based on past trends and drivers. This has been reliable due to the past stable growth. However, there are certain drivers which can influence past trends, for example changes in technology or a downturn in the economy which changes growth.

Forecasting the demand of larger consumers is also based on assumptions of the impact of key economic and environmental drivers such as the availability of land for irrigation and the return dairy farmers are receiving for milk fat. These forecasts can be made more accurate if timely information from large consumers on their future load requirements is given to us. However this information can be delayed as developers wish to keep their projects confidential making network planning difficult. Developers may see power lines outside of their sites and assume that capacity is be available for them.

By discussing forward planning with industry representatives, we can get a reasonably accurate picture at a farm development level for one or two years ahead and take account of this information when interpreting network load modelling. Therefore the formation of an industry liaison team will help in this regard. The liaison team is set to be established in the 2014/15 period and will look to liaise with industry to determine load requirements and also to communicate our requirements for timely information.

Our estimates of future demand are described in Chapter 9 GXP, Substation and Sub–transmission Assets, while our assumptions of how drivers will impact on the network in the future are made in section 1.2.

5.2.5 Impact of Growth on the Existing Network

This section discusses the impact of energy demand (load growth) on network planning.

5.2.5.1 Trigger Points for New Capacity

Once load growth is determined the impact of growth (or other drivers such as security of supply) on network assets must be determined. This involves assessing whether load growth will result in any defined trigger points for asset location, capacity, reliability, security or voltage being breached. These trigger points are outlined below in Table 5.2

Table 5.2 Summary of capacity trigger points

Asset category	Extension	Up-sizing				Renewal
	Location trigger	Capacity trigger	Reliability trigger	Security trigger	Voltage trigger	Condition trigger
LV lines and cables	Existing LV lines and cables don't reach the required location.	Load change blows fuse - tends to manifest as voltage constraint first.	LV feeder peaks to overload 400 V CB – reconfigure feeder balance.	Not applicable – individual customer can pay for higher security.	Voltage at consumers' premises consistently drops below 0.94pu.	PIL cable condition or conductor or pole condition poor or at end of life.
Distribution substations	Load cannot be reasonably supplied by LV configuration therefore requires larger or additional distribution sub and LV cables.	Where fitted, MDI reading exceeds 80% of nameplate rating.	Design prone to poor performance – partial discharge or poor lightning impulse response.	Excursion beyond triggers specified in section 5.2.2	Voltage at LV terminals consistently drops below 1.0pu.	Condition assessed – rust, oil leaks, high losses, load drops below capacity (downsize).
Distribution lines and cables	Load cannot be reasonably supplied by configuration therefore requires network	Conductor current or fault level exceeds thermal rating.	Snow loading needs higher mechanical strength. Cable fault damages	Excursion beyond triggers specified in section 5.2.2	Voltage at HV terminals of transformer consistently drops below 10.5kV and	Age hardening or loss of conductor strength. Corrosion of steel

Asset category	Extension	Up-sizing				Renewal
	Location trigger	Capacity trigger	Reliability trigger	Security trigger	Voltage trigger	Condition trigger
	extension with new distribution lines or cables.		light screens or partial discharge is poor		cannot be compensated by local tap setting.	core. Drying out of insulated papers. Water trees in XLPE cable
Zone substations	Load cannot be reasonably supplied by distribution configuration therefore requires new sub-trans lines or cables and zone sub.	Max demand consistently exceeds 100% of nameplate rating.	Loss of N-1 level.	Excursion beyond triggers specified in section 5.2.2	Regulation exceeds Tap Changer range.	Age and condition – Poor DGA or pd results.
Sub-transmission lines and cables	Load cannot be reasonably supplied by distribution configuration therefore requires new sub-trans lines or cables and zone sub.	Conductor current exceeds thermal rating or creates ground clearance violation or accelerated cable ageing.	Changed thermal limits of cable resistivity. Flood, wind or snow prone areas require better mechanical support.	Excursion beyond triggers specified in section 5.2.2	Line or cable regulation exceeded from load growth.	Age and condition of conductor, insulation levels or supports.

Extending, upsizing and renewal involve CAPEX, it is our preference to avoid CAPEX if other alternatives are available. This discussion also links strongly to the discussion of asset life cycle in Chapter 0.

If trigger points are breached we move to a range of options in order to bring the asset’s operating parameters back to an acceptable range. These options are described in Table 5.2 above, which also embodies an overall preference for avoiding new capital expenditure.

5.2.6 Impact of Electric Vehicles and Photo Voltaic Generation on Planning

This section discusses the impact of electric vehicles and photo voltaic distribution on network planning.

5.2.6.1 Electric Vehicles

Electric vehicles (EV) could have a significant impact on demand for energy in the long run, however the demand for EVs at present is limited.

Our best indicator is that EV sales will develop around 2020. Some 1 MW has been added in load predictions for TIM to allow for initial uptake. Like all new technologies we need to see some movement before proper planning to supply the load can take place.

Overseas markets will undoubtedly lead the way in the deployment of electric vehicles and consequently we can expect to see products and solutions offered for any distribution network issues that are created by the expansion of electric vehicles into the South Canterbury vehicle fleet.

5.2.6.2 The Impact of Photo Voltaic Distributed Generation on Planning

The growth of photo voltaic distributed generation (PV) may eventually reduce the flow of energy from the power stations into our network during daylight hours, however PV will not reduce evening in-flows particularly in winter. GXP and zone substation maximum demands will similarly not be reduced during evening hours. Also, both Energy (MWh) and Power (MW) levels at some rural zone substations may not be greatly affected during daylight hours if urban distributed generation is fed to them via the GXP's, local Transpower Transmission and via our sub-transmission lines. However, should rural property owners begin to 'energy farm' this could result in net flows away from rural zone subs during daylight hours.

Over the AMP planning period, we must monitor the progress of the up-take of both PV and EV technologies, driven as they will be by their relative price and availability in NZ and South Canterbury in particular, compared with the conventional sources of electrical energy and fossil fuel powered vehicles.

5.2.7 Options for Meeting Demand

Our guiding principle is to minimise the level of investment ahead of demand whilst minimising the costs associated with not realizing a return over the life of the asset (stranding or early replacement) as well as the costs of doing the work.

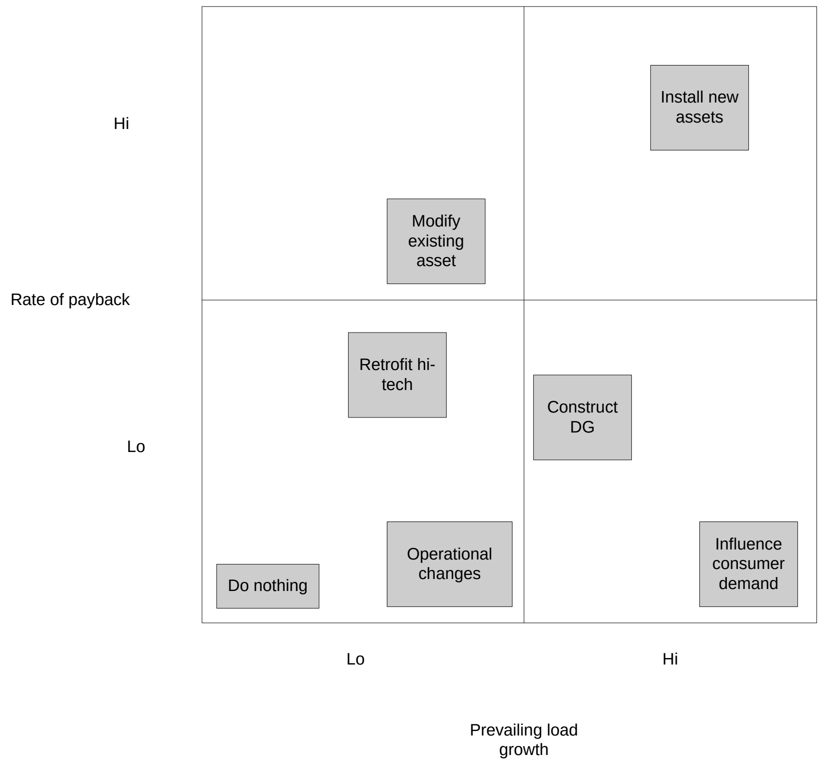
Table 5.3 below, shows the options that are considered when capacity is exceeded or expected to be exceeded.

Table 5.3 Options for when capacity is exceeded

Option	Description of 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 chief executive and board that the do nothing option did not represent an unacceptable increase in risk to ourselves. An example of where a do nothing option might be adopted is where 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 winding up a tap changer to mitigate a voltage problem. The downside to this approach is that it may increase line losses, reduce security of supply, or compromise protection settings.
Influence consumers	To alter consumer consumption patterns so that assets perform at levels below the trigger points. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain 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 eg water being released from a dam that could be used in a hydro generator, or process steam going to waste.
Modify an asset	The trigger point will move to a level that is not exceeded eg by adding forced cooling. 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.
Retrofitting	Retrofitting high-technology devices that can exploit the features of existing assets. Examples might be using (though not done presently) remotely switched air-breaks to improve reliability, using advanced software to thermally re-rate heavily-loaded lines, or retrofitting core temperature sensors on large transformers so they can be worked harder.
Install new assets	A greater capacity will increase the assets trigger point to a level at which it is not exceeded. Examples would be replacing a 200 kVA distribution transformer with a 300 kVA transformer or replacing light conductor with a heavier conductor.

In identifying solutions for meeting future demands for capacity, reliability, security and voltage we consider options that cover the above range of categories. The benefit-cost ratio of each option is considered (including estimates of the benefits of environmental compliance and public safety) and the option yielding the greatest benefit is adopted. The model in Figure 5.4 over page, is used to broadly guide this process.

Figure 5.4 Options for meeting demand



5.2.8 Factoring in Capacity Constraints

When considering what options are available to meet demand our planners must also take into account the existing capacity constraints on the network which will influence the range of options available to us.

Existing network capacity constraints and intended remedies are listed in Chapter 9 under the relevant GXP and substation and summarised in section 5.3.6 The Effect of Constraints on Planning at page 141.

5.2.8.1 Non-electrical Constraints

Our network is not only constrained electrically, but it is also constrained by the environment within which it is constructed. These are discussed below.

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, equipment designed for this environment is used (Refer also to Section 2.4.2).

State Highways 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 and 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.

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 customer 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 customer needs are suddenly unveiled or delayed when constraints in completing projects make it unviable to complete within the budget year and should be deferred.

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.

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.

5.2.9 Capacity of New Assets Required

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.

5.2.9.1 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[15] 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 customer 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 loss of supply could have significant economic and possible environmental consequences.

Our network does not currently conform to the security of supply standards. It is the intention of this plan to achieve the security of supply standard referred to above within the 10 year planning period adopted within this plan.

Existing security levels are listed in Chapter 9 GXP, Substation and Sub–transmission Assets.

5.2.9.2 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 voltage, except for momentary fluctuations (ie voltage dips).

Equipment includes: transformers, fitted with On Load Tap Changers (OLTCs), voltage regulators, capacitor banks, cables and overhead conductors.

5.2.9.3 Harmonics

Voltage and current harmonics are becoming more important with the large number of variable speed drives (VSD's) being installed on our network, specifically to drive irrigation pump motors.

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

Since harmonics generated by one customer can adversely affect the supply to adjacent customers, require customers 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 customers and suppliers of VSD's to design filters to limit the harmonics injected into the network.

5.2.9.4 Fault Levels

We have some of the highest 11 kV fault levels in New Zealand at the Timaru 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 are working with Transpower to reduce the Timaru fault levels. For example, earth faults at Timaru were reduced when NERs were installed in 2012, and phase fault levels are proposed to be lowered in the future when the three new supply transformers operate with two in service and one on hot standby. 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. There are doubts the transformers will voltage regulate well, once commissioned any doubts will be resolved.

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

5.2.9.5 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 new plant to be connected to the network. Combination of Voltage Regulators and Capacitor banks are 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 are important since over compensation can lead to high voltage during light loading conditions where potential rise is seen to become an issue, adjacent Voltage Regulators are used to lower potential.

5.2.10 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:

5.2.10.1 Sub-transmission Lines

For more information on sub-transmission lines please refer to Chapter 9 GXP, Substation and Sub–transmission Assets. Table 5.4 below, describes key characteristics of equipment chosen for sub-transmission lines.

Table 5.4 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 Ltd,
Insulators	We have where possible kept with traditional glass and porcelain insulation. Surge arrestors are the main exception. For the sake of public safety polymers other than EDPM are installed. Most polymer surge arrestor 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.

5.2.10.2 Sub-transmission Cables

For more information on sub-transmission cables please refer to Chapter 9 GXP, Substation and Sub–transmission Assets. Table 5.5 below, describes key characteristics of equipment chosen for sub-transmission cables.

Table 5.5 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 North St 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 Arrestors	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.

5.2.10.3 Zone substations

For more information on zone substations please refer to Chapter 9 GXP, Substation and Sub–transmission Assets. Table 5.6 over page, describes key characteristics of equipment chosen for zone substations.

Table 5.6 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.

Equipment Type	Description
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.

5.2.10.4 Distribution Lines

Table 5.7 below, describes key characteristics of equipment chosen for distribution lines.

Table 5.7 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.

5.2.10.5 Distribution Cables

Table 5.8 over page, describes key characteristics of equipment chosen for distribution cables.

Table 5.8 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 Arrestors	11 kV, Ohio Brass Station Class ESP, Cooper Evolution 10 kV Silicon.

5.2.10.6 Distribution Substations—Pole Mounted

For more information on distribution substations—pole mounted please refer to Chapter 9 GXP, Substation and Sub–transmission Assets. Table 5.9 below, describes key characteristics of equipment chosen for distribution substations—pole mounted.

Table 5.9 Characteristics of equipment used for distribution cables

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.

Equipment Type	Description
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.

5.2.10.7 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 low voltage interconnected to other transformer’s low voltage windings.

Table 5.10 over page, describes key characteristics of equipment chosen for the selection of sites.

An example of an urban substation is shown in Figure 5.5 below. North St substation sits just south of the Timaru CBD.

Figure 5.5 North Street substation

Table 5.10 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	Pad mount transformers are generally fitted with a maximum demand instrument and street light controls from the ripple relay system.

5.2.10.8 Low Voltage Reticulation

For information on low voltage reticulation please refer to Table 5.11 below, describes key characteristics of equipment chosen for low voltage reticulation.

Table 5.11 Characteristics of equipment used for low voltage 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 delivery 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 customers may have smaller horizontal fuse disconnects installed.

5.2.11 Non Network Solutions

An 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 verses continued maintenance or refurbishment is subject to economic analysis, to determine the most cost effective option, and 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 customer 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 for Albury and Tekapo GXPs for 2 to 5 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 transformers (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 customers. These can run separate at 400 V, ganged at 400 V or be stepped up to 11 kV.

5.2.11.1 Demand Side Management

Demand side management tools consist of contracting customers 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 customer 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 customer's 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 customers 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.

5.2.12 Our Policy for 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.

Figure 5.6 Installation of PV panels

Table 5.12 below, summarises the positive and negative aspects of distributed generation.

Table 5.12 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 GXP's. 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 assets 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.

5.2.12.1 Connection Terms and Conditions for Distributed Generation

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

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.

5.2.12.2 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.

5.2.12.3 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.

5.2.12.4 Opuha Dam

We have had experience operating the Opuha Dam and the associated concepts of distributed generation. This hydro facility has a network embedded 7 MW generator which exports to the national grid through Transpower's Albury substation. The generator operates to pass environmental and irrigation flow releases and has a 20% duty factor, limiting its contribution to Transmission peak reduction. The generator is used to island the local community when grid supply is unavailable due to maintenance of the transmission substation equipment. The station is unable to; black start, run on part load due to vibration issues, offer significant inertia leading to poor speed control and instability - hence islanding does not afford much security.

5.2.13 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:

- 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 (Opuha 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.

5.2.13.1 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 Engineer's Council in the late 1970's. P2/5 was a strictly deterministic standard ie 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.

5.2.13.2 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.

5.2.13.3 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.

5.2.13.4 Existing Security Standards

Existing levels of security at GXP and zone substation level are found in Chapter 9 GXP, Substation and Sub–transmission Assets.

5.2.14 Choosing the Best Option to Meet Demand

Once it is established that there is significant load growth on the network, and the effect this will have on the existing network, options are proposed to best meet the load growth requirements.

Once options are established, with input from the Network Manager, asset manager, and the engineers, the costs and benefits of the respective options are analysed with due regard to appropriate decision making techniques, risk assessments and network level optimisation as appropriate. The cost and benefits of each option are then assessed to determine the most appropriate option.

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

5.2.15 Implementing the Preferred Option

Once the preferred option is chosen the Network Manager, with input from 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 Board.

Projects placed into the works plan are prioritised in the order at Table 5.13 below.

Table 5.13 Criteria for assessing 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 works plan, the project will proceed as follows:

- Flesh out conceptual option used to determine if investment criteria are met.
- 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.
- Address resource consent, property ownership and any Transpower issues.
- Perform detailed design, including the preparation of drawings, equipment and construction specifications, and tender documents as necessary and procure critical major components.
- Tender out construction stage.
- Award tender.
- Construction stage.
- Commissioning stage.
- Close out and de-brief project after construction.

5.3 Demand Forecasts

Demand forecasts for GXP's, sub-transmission, and zone substations assets can be found at Chapter 9 GXP, Substation and Sub–transmission Assets.

Demand forecasting involves modelling historical peak demand at GXP, substation and feeder level to establish relationships between key variables (rainfall, temperature, and so on) and load demanded based on data from previous years. Where relationships between a variable and peak demand at GXP, substation or feeder level can be established, demand forecasts can be modelled to determine the impact to changes in variables including dry years and higher or lower temperatures.

If no correlation can be found, due to mixed demand (ie irrigation and urban at substation level), the combined experience of the planning team is utilised to estimate the impact of key drivers on future load, where the future load has been extrapolated from past data.

Residential demand begins with extrapolating a trend line from the past four years of monthly peak demand at GXP level. The likely impact of environmental legislation on heating, population changes and significant economic changes isthen added. The global financial crisis for example is deemed to have had a significant 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 below.

Our planning team has assessed the correlation between rainfall and temperature (using data from Environment Canterbury for the last 10+ years) and demand at substation level. There has been no correlation established at substation level most likely because of the mixed load (both dairy and urban demand) at each substation. This approach will again be undertaken to determine this relationship at feeder level. Please also see discussion in Chapter 8 for other intended improvements to our planning process. Historic GXP Demand and Growth Figure below, shows the 15 year growth rate (blue dotted line) as well as the growth rate over the last four years (pink dotted line).

The line equation accompanying each trend line label (dotted lines in all of the graphs) shows the slope of the line which equates to the monthly change in demand. This is multiplied by 12 to equal the annual change in demand.

Figure 5.7 Network load growth

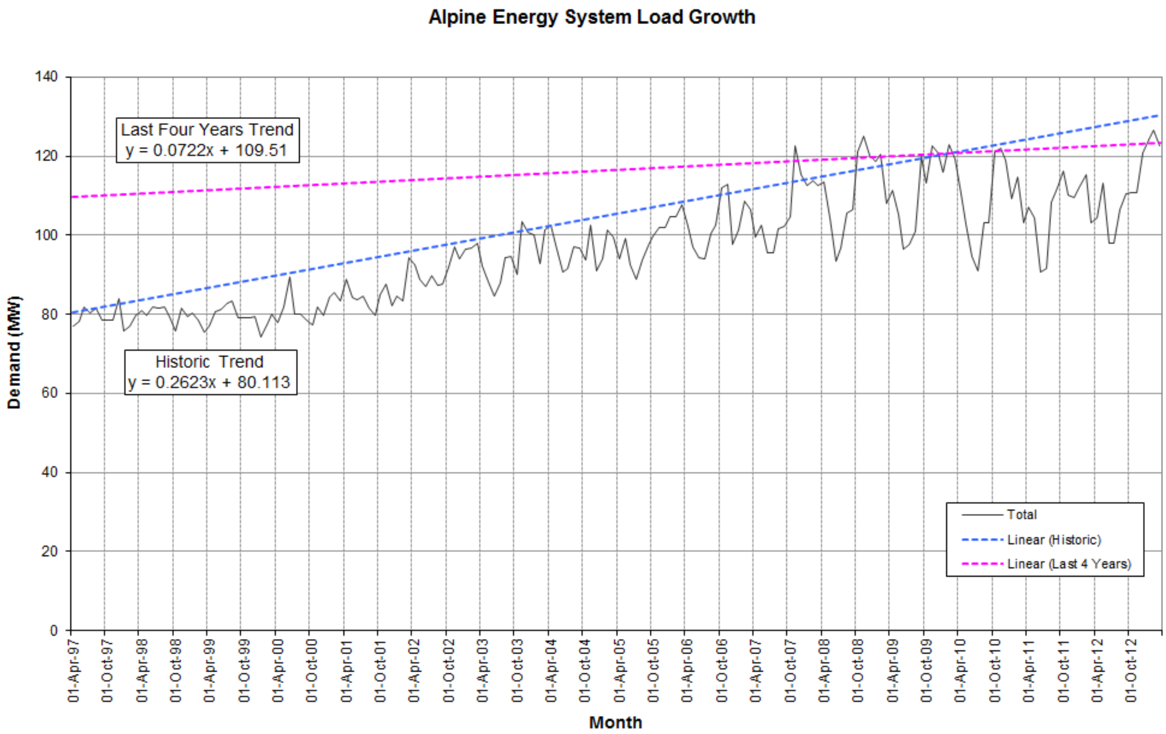


Figure 5.8 and Figure 5.9 over page, show historical trends of anytime maximum demand and the total maximum demand growth rate for each GXP (shown by the dotted trend line in each case).

Figure 5.8 Load growth by GXP (1)

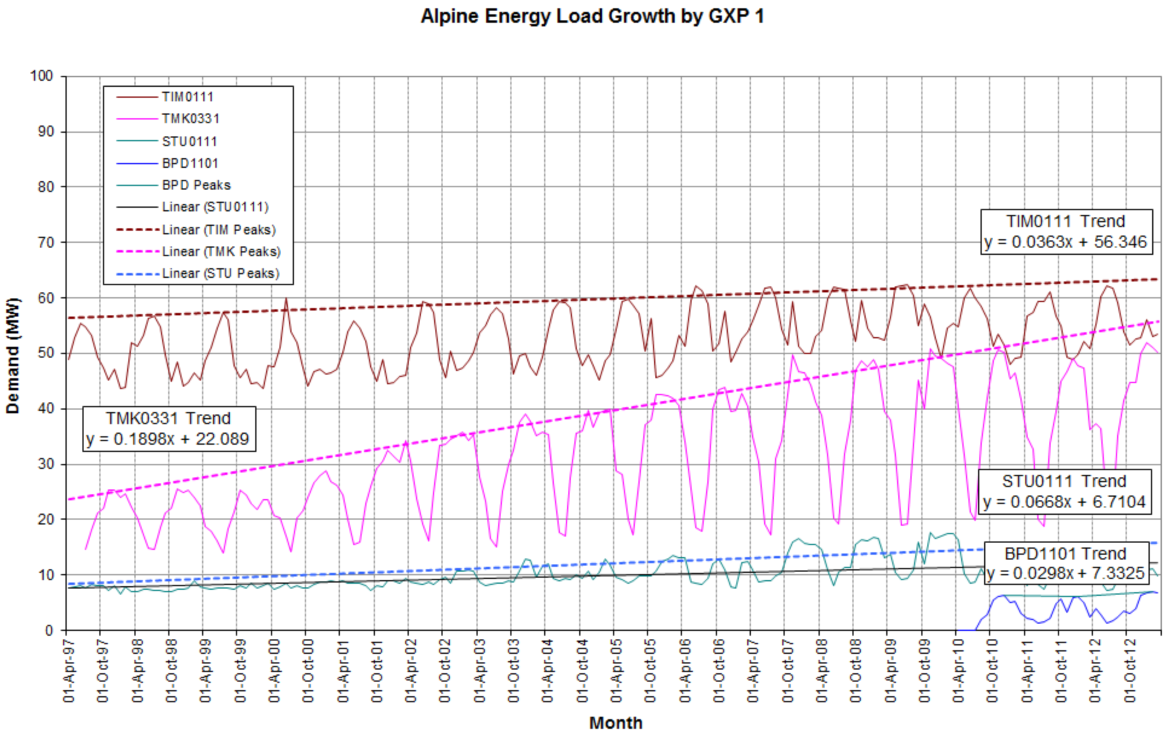
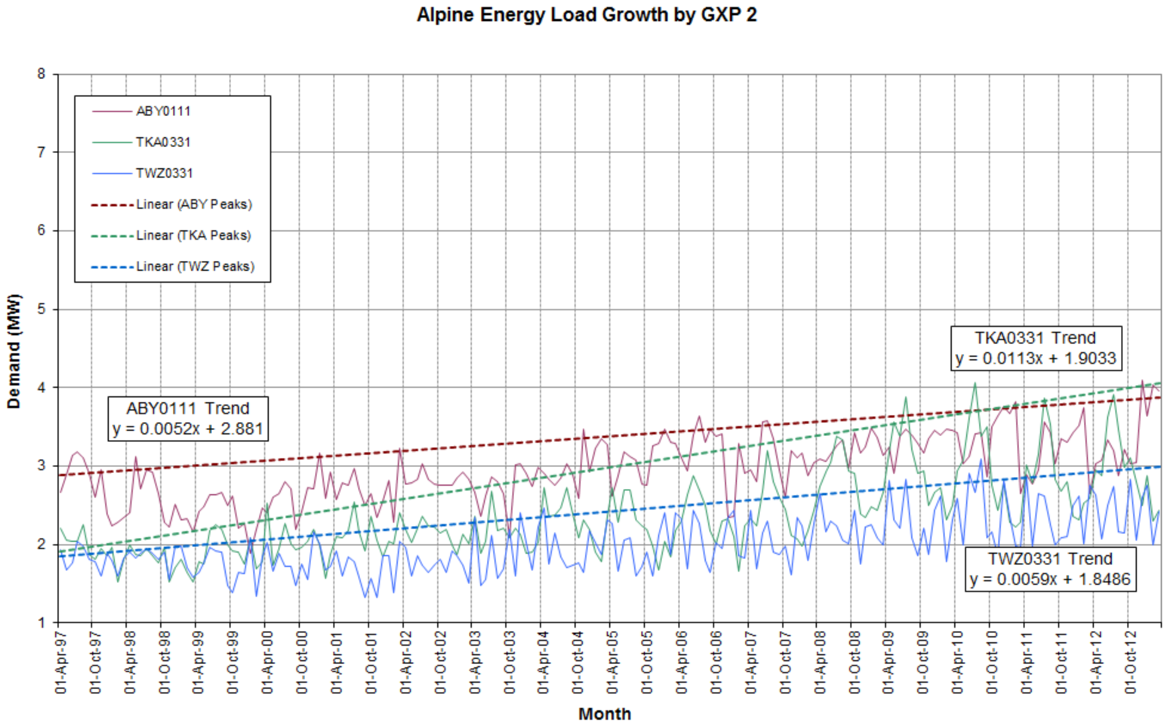


Figure 5.9 Load growth by GXP (2)



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

The Christchurch earthquakes have helped the recovery of the economy in South Canterbury and since the beginning of 2013 load growth has begun to recover. This recovery has also been strongly helped by the continuing investment in the dairy industry as returns to this sector remain firm.

Based on trends elsewhere in NZ, and dairy and irrigation growth apart, the load growth can be expected to remain relatively modest for the planning period. The slow-down in the growth has bought some time to complete necessary network upgrades, maintenance and new capital projects required to sustain existing load and any reasonable future growth.

The data in each of the figures is summarised in Table 5.14 below. The figures reported in the table are current to March 2013 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 (1997 to 2012).

Table 5.14 Historic GXP demand and growth

GXP	Half Hour Max Demand	Monthly Growth (MW)	Annual Growth (MW)	Annual Growth (%)
ABY0111	4.094	0.005	0.062	1.524
STU0111	7.026	0.030	0.358	5.090
BPD1101	11.122	0.067	0.802	7.207
TIM0111	62.222	0.036	0.436	0.700
TKA0331	3.918	0.011	0.136	3.461
TMK0331	52.006	0.190	2.278	4.379
TWZ0331	2.828	0.006	0.071	2.504
Total	**143.216**	**0.345**	**4.141**	**2.892**

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 5.15 below. These step demands and above assumptions are incorporated into our load growth projections for GXP's.

Table 5.15 Projects adding step demand increases by GXP

Project	Demand (MW)	Year	GXP
Ecotech plastics	0.8	2014 Plant installed – load not yet realised)	Timaru
TDC Milliscreen	0.25	2014	Timaru
Washdyke Flour Mill	0.5	2014	Timaru

Project	Demand (MW)	Year	GXP
Washdyke Salmon factory	0.75	2014	Timaru
By Products Stage 3	0.55	2014	Timaru
Rangitata Irrigation	1.0	2013	Temuka
Rangitata Irrigation	3.0	2014	Temuka
Rangitata Irrigation	3.0	2015	Temuka
Hydro Grand	0.5	2015	Timaru
Oceana Dairy Ltd Stage 1	5	2014	Bell's Pond then transfer to Cooneys Road
Oceana Dairy Ltd Stage 2	5	2016	Bell's Pond then transfer to Cooneys Road
Oceana Dairy Ltd Stage 3	5	2018	Bell's Pond then transfer to Cooneys Road
Oceana Dairy Ltd Stage 4	5	2020	Bell's Pond then transfer to Cooneys Road
Tekapo Village Development	1.0	2014	Tekapo
Studholme Stage 2	0 (Removed as Darfield is focus)	2015	Studholme
Irrigation Pukaki	2.5	2016	Twizel
Irrigation OHC	0.8	2016	Twizel
Irrigation Haldon	0.5	2016	Twizel
Ivey Irrigation	0.2	2016	Twizel
Holcim Cement	4-5	2015	Timaru
Waihoa Downs Irrigation	10.0	2017	Bell's Pond
Hunter Downs Irrigation	34.0	2018	Bell's Pond, Studholme, St. Andrews
Clandeboye Drier 4	8.0	2020	Temuka
Electric Motor Vehicle	1.0	Progressively to 2024	TIM

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 Chapter 9 GXP, Substation and Sub–transmission Assets, and summarised in Table 5.16 below.

Table 5.16 Load growth by GXP

GXP Substation (Season Peak)	Forecast Growth Trend (Total MW MD) for the year ended 31 March										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024

GXP Substation (Season Peak)	Forecast Growth Trend (Total MW MD) for the year ended 31 March										
Albury (Summer)	4.2	4.3	4.3	4.4	4.5	4.5	4.6	4.6	4.7	4.7	4.8
Bell's Pond (Summer)	14.4	15.8	32.4	34.1	24.9	25.7	26.6	27.5	28.5	29.5	30.6
Cooneys Rd (All) (potentially off BPD – included in BPD)	0.0	0.0	0.0	0.0	15.0	15.0	20.0	20.0	20.0	20.0	20.0
St. Andrews (Summer)	0.0	0.0	0.0	0.0	0.0	26.0	27.2	28.3	29.3	30.1	30.9
Studholme (Summer)	11.8	12.1	12.4	12.8	22.1	23.6	25.0	26.3	27.5	28.5	29.6
Tekapo Sum (Autumn/Spring)	5.0	5.2	5.3	5.5	5.6	5.8	5.9	6.1	6.2	6.4	6.6
Temuka (Summer)	58.2	63.5	65.6	66.9	68.2	69.6	79.0	80.5	82.1	83.8	85.5
Timaru 11 kV (Winter)	66.1	70.7	71.6	72.2	71.9	72.5	73.2	73.9	74.7	75.2	74.7
Twizel (Autumn/Spring)	3.2	3.7	8.1	9.5	9.9	10.4	10.8	10.9	10.9	11.0	11.1

5.3.3 Estimated Demand at Zone Substation Level

Information on planning at zone substation level can be found in Chapter 9 GXP, Substation and Sub–transmission Assets. Table 5.17 below summarises demand growth at zone substation level.

Table 5.17 Zone Substation Demand Growth

Zone Sub	2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
Albury 11 kV feeders	1.81 (Summer)	1.26% historic on ABY Residential Load Small subdivision development	2.1 (winter)	Transpower asset under their management. Overall load not expected to breach Transpower's capacity unless Totara Valley Sub built.
Fairlie	2.37 (Summer)	1.51% historic on ABY Residential Load Small subdivision development	2.7 (winter)	Regulator upsizing or transformer with OLTC - expect demand to grow from current demand of 2.4 MW to about 3 MW over planning period.
Bell's Pond	7.0 (summer)	8.95% per year expected Residential load Dairy and Irrigation development	30.6 (summer)	New sub to offload Studholme and provide more security and capacity. Work needed to carry load which depends on mooted projects progressing.
St. Andrews	(Summer)	4.62% per year expected as TMK	30.9	New sub to offload Studholme and Pareora and provide more security and

Zone Sub	2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
		Residential load Dairy and Irrigation development	(summer)	capacity.
Studholme	11.5 (Summer)	3.194% per year expected as TMK Residential load Dairy and Irrigation development	30.5 (summer)	Transformer upsizing required pending load split for Hunter between STU and STA. 11 kV Swbd upsizing required after 24 MVA.
Timaru 11 kV board	64.0 (Winter)	0.7% historic some steps expected to come Residential Growth Heat Pump uptake Industry Growth (Washdyke)	75.7 (winter)	Up-sizing Transpower supply transformers. If a surprise load establishes in excess of 10 MW toward end of period, transfer some load to a new 33 kV GXP potential.
Pleasant Point	4.4 (Summer)	3.175% per year expected as TMK Residential load Dairy and Irrigation development.	6.22 (summer)	Existing transformer rated for the period. Some security via 11 kV back up from TIM and ABY. Possible sub built nearer irrigation load at Totara Valley to improve security.
Pareora	8.4 (Summer)	3.175% per year expected as TMK until SAW then 2% Residential load Dairy and irrigation development.	9.4 (summer)	Up-sizing of Sub-transmission 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 St. Andrews GXP as it eventuates.
Tekapo	3.2 (Winter / shoulder)	3.338% historic on TKA Residential load Subdivision and CBD development Tourism development.	5.3 (winter / shoulder)	Substation Transformer needs upgrading as it overloads on peak - expect demand to grow from current demand of 3.2 MW to about 5.3 MW over planning period.
Mt Cook and Glentanner	0.8 (Winter / shoulder)	3.338% historic on TKA Tourism development.	1.4 (winter / shoulder)	Larger capacity transformer bank for Hermitage - expect demand to grow from current demand of 0.8 MW to about 1.4 MW over planning period.
Temuka	52.0	4.6% historic on	83.8	Load growth due to expansion at Clandeboye and Rangitata. If realised

Zone Sub	2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
	(Summer)	TMK Residential load Dairy and Irrigation development.	(summer)	this would require a transmission solution to be discussed with Transpower
Clandeboye 1 and 2	25 (Summer)	4.63% historic on TMK Process Expansion and new Dryer.	45 (summer)	None required for local assets – Substation and sub-transmission capacity available. Additional CB's at substations and 11 kV cabling to new RMU and Distribution Tx's required - expect demand to grow from current demand of 25 MW to about 45 MW by the end of the planning period. Existing assets can meet this demand and retain n-1 security.
Geraldine	5.9 (Summer)	4.63% historic on TMK Residential load Dairy and irrigation development.	7.8 (summer)	Local concern may lead to a second 33 kV circuit to provide (N-1) security - expect demand to grow from present demand of 5.9 MW to about 7.8 MW by the end of the planning period.
Rangitata	9.5 (Summer)	4.63% historic on TMK Dairy and Irrigation development.	13.5 (summer)	33 kV circuit prepared to provide (N-1) security - expect demand to grow from current demand of 7 MW to about 13.5 MW by the end of the planning period. Note some of RGA load can be transferred to Temuka and Geraldine as a temporary measure.
Twizel	2.8 (shoulder)	2.207% historic on TWZ Residential load Large scale Subdivision Dairy and Irrigation development	3.6 (shoulder)	Rebuild Substation as part of future development. Extend 33 kV line to new irrigation development and install smaller dedicated substation.
Pukaki/ Simons Pass	(Summer)	Dairy and Irrigation development	2.5 (summer)	New substation off Twizel.
Haldon	(Summer)	Dairy and Irrigation development	1.3 (summer)	New substation off Twizel via Pukaki/Simons Pass. Some offload of Tekapo on Lillybank and Balmoral feeders.

5.3.4 Estimated Feeder Demand

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

5.3.5 Effect GXP Forecasts on Supply Security

The continuing load growth on the Albury, Bell's Pond, Studholme, Temuka and Timaru GXP's as well as forecast load increases at Tekapo and Twizel will see capacity constraints within the planning period of the AMP. These are explained further in Chapter 9. A summary of how we provide for growth is shown in Table 5.18 below.

Table 5.18 Rate and nature of GXP growth and provisions made

GXP	Rate and nature of growth	Provision for growth
Albury	Med – rural	New investment if Totara Valley connected
Bell's Pond	High - rural	New investment
Studholme	High - rural	New investment
Tekapo	Med – subdivision and tourism business	Upgrade Zone sub
Temuka	High – rural and industrial	GXP investment at Temuka or Orari
Timaru	High – industrial / commercial	GXP investment underway
Twizel	Med – rural and subdivision	Upgrade / new zone substation

5.3.6 The Effect of Constraints on Planning

Network constraints are more fully described in Chapter 9 GXP, Substation and Sub–transmission Assets. A summary of constraints is found in Table 5.19 below.

Table 5.19 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.
Studholme GXP Supply Security to 110° kV bus	Upgrade N security to N-1	From Feb 2010 110 kV bus is closed during peak dairy season – Partial fix during high cost part of year. Ultimate, new investment in transmission line. Transpower discussion via Lower Waitaki Project.
Studholme GXP Supply Security via transformer capacity	Upgrade N security to N-1	Interim, partial off load to Bell's Pond substation (2010) Ultimate, New Investment in Transformers and unitised HV CBs.
Bell's Pond 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

Constraint	Description	Intended remedy
		available by 2018.
Bell's Pond 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).
St Andrew's, Waimate	Lack of capacity for Hunter Downs irrigation	Lack of capacity in 11 kV network to supply Hunter Downs irrigation. 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 Orari with new GXP at Clandeboye to off load 40 MW from Timaru, or construct double cct 220 kV line Livingstone-Islington cct to Temuka and offload Temuka from 110 kV lines and Timaru bus.
Timaru 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 Timaru 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 North St 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 North St 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).
Timaru Sub-	Heavy cable loadings	Research feasibility to install four 11 kV 0.5 Ohm reactors in Grasmere and Hunt sub-transmission

Constraint	Description	Intended remedy
transmission to CBD		to North St to force load onto new North-Timaru cables OR Ultimately establish city 33/11 zone substation off 33 kV TIM GXP (timing uncertain).
Pareora 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 St. Andrews GXP for partial load transfer (2017-18).
Pleasant Point 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	Request Transpower upgrade their Timaru 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 Orari bussing point to offload Temuka GXP or possibly establish new Temuka GXP off the ISL-LIV 220 kV circuit.
Temuka GXP Supply Security	Load constraint over 60 MVA transformers, 70 MVA on lines, 71 MVA 33 kV switchboard	Request Transpower upgrade their Timaru 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 Orari bussing point to offload Temuka GXP or possibly establish new Temuka GXP off the ISL-LIV 220 kV circuit.
Rangitata 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.

Constraint	Description	Intended remedy
Geraldine 33 kV sub-trans 1 line regulation	Voltage constraint over 8.64 MVA of load (6% volt drop)	Watch on GLD loading, load may be able to go back to RGA depending on final irrigation scheme load.
Fairlie 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 Pareora. Awaits mobile substation.
Otaio Feeder regulation (STU) St Andrews Feeder regulation (PAR) Both to same area – feed from both ends	Voltage constraint at end of feeders.	New voltage regulator installed at Cup and Saucer and loaded with capacitors, feeder at end of capacity from both Studholme and Pareora. Look to load up Pareora's Holme Station feeder to offload Pareora feed toward Otaio. Off load Dairy Factory feeders when second drier established (timing unknown), or if drier delayed put diary 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.	Plan was to install capacitor 2013/14 plan but no locations available in CBD.
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.
Studholme 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 low voltage 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.

5.3.7 Assumptions Made when Planning

When assessing load growth our planning team takes into account estimated growth at GXP level based on historical trends as described above. Growth is expected to continue along these lines based on the following assumptions as well as those assumptions found in Chapter 2:

- There will be no significant shifts in the underlying technology of electricity distribution in the next 5 to 10 years.
- Embedded or standby generation will not be a significant factor before 2015 in either the southern or northern areas due to price barrier of new technology.
- No major transportations corridors will be established prior to 2015
- Areas with winter peak demand substations (Timaru, and Tekapo) will have new connections that will continue to be predominately residential and increase at the average rate of 1 to 2% per year.
- Areas with summer peak demand substations such as Bell's Pond, Clandeboye, Studholme, Temuka, and Albury will have new connections driven by dairy, crop, and irrigation developments. Peak demand is likely to remain strong for the planning period and increase at an average rate of 3% per year.
- Diversity across each zone substation is assumed to be constant through the forecast period.
- Constant load factor throughout forecast period and is set at the average for the winter period on each GXP.
- The option must align with our mission statement, corporate goals and responsibilities.
- Capacity investment will lead the gradual filling up of new load.
- Infrastructure assets have long lives, hence future predictions of what capacity will be required for new load contains a degree of uncertainty and financial risk.
- The need to limit investment to what can be recovered under the default price-quality path threshold or alternatively develop a customized price path in agreement with the Commerce Commission to make the appropriate level of investment.
- The standard size of many components (which makes investment lumpy).

  The one-off costs of construction, consenting, traffic management, access to land and reinstatement of sealed surfaces (which make it preferable to install large lumps of capacity and not go back to the site).

All demand forecasts will be reviewed annually.

5.3.8 Issues Arising from Estimated Demand

Significant issues arising from the Demand Forecasts in this section are found in Chapter 9 GXP, Substation and Sub–transmission Assets.

5.3.8.1 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 customers 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.

5.3.9 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 max 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 equipment. It also makes it difficult to arrange access to equipment for replacement or maintenance without interrupting irrigation and dairy milking cycles.

5.4 Network Development Plan

5.4.1 GXP, Zone Substation, and Sub-transmission

Please refer to Chapter 9 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. Figure 5.10 below is a photograph of the Albury GXP.

Figure 5.10 Albury Substation

5.4.2 Voltage Support

This section describes network plans for voltage support.

5.4.2.1 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, so an annual fund will be required to allow suitable voltage regulator installations to match the growing load.

5.4.2.2 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, 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 Albury and Tekapo 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. This needs constant review.

5.4.3 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. 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 reduction in SAIDIs. Research will determine which feeders have the highest fault incidence leading to the best application of reclosers.

5.4.4 Distribution Cables

New feeder cables will be required for substation work at Studholme. The detail is established on a case by case basis. Generally 300 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 Geraldine 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.

5.4.5 Protection, Control and Measurement

5.4.5.1 Protection

We have a mix of protection equipment installed. Recent substations have had microprocessor equipment like SEL, MiCom and Reyrolle Argus installed. These technologies have a nominal life of 20 years. The oldest (Reyrolle Argus) is 1997 era and was replaced in 2012/13 as their migration to SCADA was difficult, it was more economical to replace early.

There is a range of static protection like Combiflex and SPACOM (Hunt St.); this too has a nominal 20 year life. The replacement of some of this equipment is occurring naturally, for example combiflex has recently been removed from Pleasant Point and Pareora substations. Further planning is required to replace the remaining equipment.

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 to that of the switchgear (40 years) 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 to be installed. Similar to the Reyrolle Solkor protection on the 11 kV sub–transmission cables a modern unit current differential protection will be required on new HV cabling. 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 Bell's Pond and Rangitata 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 North St. and Grasmere St.

Arc flash detection (AFD) equipment has been installed on recent switchgear at; Rangitata, North St. and Grasmere St. to work in combination with current check to clear arcing faults within the switchboard. It is proposed to retrofit this type of equipment at Hunt St. as a pseudo bus bar protection.

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

5.4.5.2 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 controllers. 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.

The last substation GLD is presently being automated. Most of the other zone substations have full control. A pole top automation programme has commenced concentrating first on making the recloser controllers ready for easy remote connexion.

5.4.5.3 Measurement

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

5.4.5.4 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.

5.5 Large Projects

This section describes and details the justification for our CAPEX Works plan. New and Upgraded Overhead Lines Projects are listed as a single category on the Works plan in the same appendix. The justification for the individual projects as listed in Appendix C, with budgets exceeding $450,000 is detailed in the following sub–sections.

5.5.1 Project Name: Pareora Sub-transmission lines reconductor

Estimated Cost: $470,000

This project comprises the upgrading of the existing Mink overhead conductor to Iodine. There are two 33 kV feeders supplying Pareora 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 recent upgrade of the substation which comprised new 33 kV switchgear and two new 9/15 MVA transformers. The project spans four years.

5.5.1.1 Justification

These two feeders supply the Pareora substation. The major load connected to this substation is SSF which 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 SSF is such that a loss of supply would result in lost product due to the requirement of freezing and cool stores.

5.5.1.2 Alternative Options/Non-network solutions

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

5.5.2 Project Name: New subdivisions and extensions

Estimated Cost: $1.5 million

This budget is based on recent expenditure to realise new connections and extensions to our network. This is mostly chargeable work for which the costs are recovered from customers and developers.

5.5.2.1 *Justification*

Electricity demand growth and new connection applications.

5.5.2.2 *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 it has not already been planned.

5.5.3 Project Name: Overhead to Underground Conversions

Estimated Cost: $650,000

This budget is to remove existing overhead lines from private land.

5.5.3.1 *Justification*

Access to these 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.

5.5.3.2 *Alternative Options/Non-network solutions*

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

5.5.4 Project Name: Timaru Substation 33 kV Upgrade

Estimated Cost: $2.0 million

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

5.5.4.1 *Justification*

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

Currently two separate 33 kV feeders to Pareora and Pleasant point is fed off the same circuit breaker. These are geographically far removed but a feeder fault on any one of the two will result in an outage on both. The result is that consumers fed off this infrastructure cannot be supplied with the reliability normally expected from systems at this voltage level.

5.5.4.2 Alternative Options/Non-network solutions

The status quo cannot be supported based on Alpine's recent reliability statistics.

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

5.5.5 Project Name: Hunt Street Substation Protection Upgrade

Estimated Cost: $530,000

This budget is to upgrade the existing feeders' electronic protection relays and migrate communications to the new fibre network from the current 485 communications system.

5.5.5.1 Justification

The current electronic protection relays are more than 20 years old which according to industry best practice is at the end of its life. Since the switchboard is 1984 vintage and in good condition, replacement would be more than ten years and probably twenty 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.

5.5.5.2 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.

5.5.6 Project Name: Fairlie Substation Upgrade

Estimated Cost: $450,000

This budget is to upgrade Fairlie substation. This entails the replacement of the existing 3 MVA transformer, 1996 vintage, and 2 MVA regulator, with a second hand 5/6.25 MVA OLTC transformer. In addition the substation will also be prepared to be able to connect our mobile substation and diesel generators. The two existing reclosers currently being used as feeder circuit breakers will be replaced with RMU's to enable the switching of individual feeder circuits, as well as to allow configuration changes that will allow future maintenance to be done without loss of supply to consumers.

5.5.6.1 Justification

Currently this substation load exceeds the rating of the voltage regulator which is used as a tap changer inside the substation. The substation transformer at 3 MVA rating is operating in excess of 80% of its nameplate rating. Maintenance is a major obstacle because it cannot be done without loss of supply to consumers. This project will not only improve our reliability statistics but also improve the quality of power supplied to the region.

5.5.6.2 Alternative Options/Non-network solutions

Doing nothing will degrade the current less than optimal power reliability to the region. We have exceeded our SAIDI targets in recent years and cannot afford not to actively engage in projects to improve this.

5.6 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 $500,000 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

5.6.1 Smart Meters

A roll out of smart meters will continue until 2016/17 where spending will curtail from $3,500 000 to $4,000,000 per annum to around $59,000 in 2017/18 and is forecast to remain at this rate.

5.6.2 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 asset management, and finance as well as the upgrading, replacement, or development of software fit for purpose. Note that our expenditure forecasts do not capitalise labour expenses.

Projects are presently been worked on are listed below.

5.6.2.1 GIS

Our IT team is developing software and processes to provide:

- One source of truth for Geospacial 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.

5.6.2.2 SharePoint

Our IT team is developing Sharepoint 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. Also 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.

5.6.2.3 Future Goals

Our future IT goals include:

- Standard platform for development, and interfacing with other applications.
- Reliable vendor support.
- Retire or replace existing with new applications.
- Documents and records management for single source of truth.
- Enterprise reporting platform that allows easy reporting by empowered end-users.
- Process automation.

5.7 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 occur 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 are determined as well as responsibilities, resources required and identification of resource constraints, risk management approach highlighted and the timings of the project.

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

Our informal approach has served us well in supporting our approach to asset management. However we have an appreciation that a more formalised approach would further develop our approach to asset management. The Alliance Agreement between us and Netcon, soon to be finalised, should help to do this.

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 as well as asset related risks.

5.8 Continuous Enhancement

5.8.1 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 the following:

- a load forecast modelling team
- an industry liaison team
- implementation of the Network Development Plan Prioritisation process.

5.8.1.1 Load Forecasting Modelling Team

The aim of this team is to model the relationships between key drivers of energy demand such as temperature and rainfall against historic demand at GXP, substation and feeder level to form robust forecasts as well as further establish levels of uncertainty.

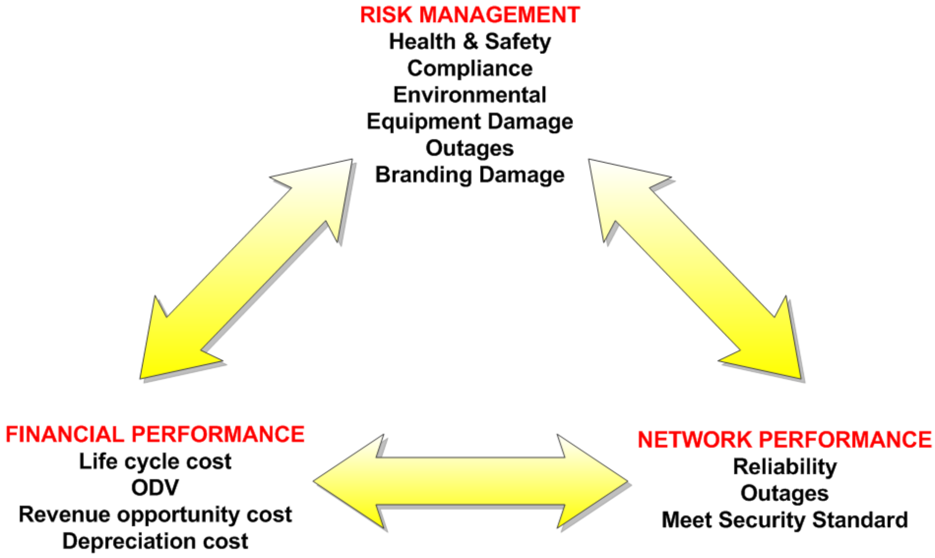
5.8.1.2 Industry Liaison Team

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.

5.8.2 Network Development Plan Prioritisation Process

The Network Development Plan (NDP) prioritisation is a new process that balances our requirements for plant performance, risk management and financial performance. This is shown graphically in Figure 5.11 below

Figure 5.11 Balancing performance driver requirements



A key enabler for the NDP process is our new risk based assessment called the Analytic Hierarchical Process (AHP). This process 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.

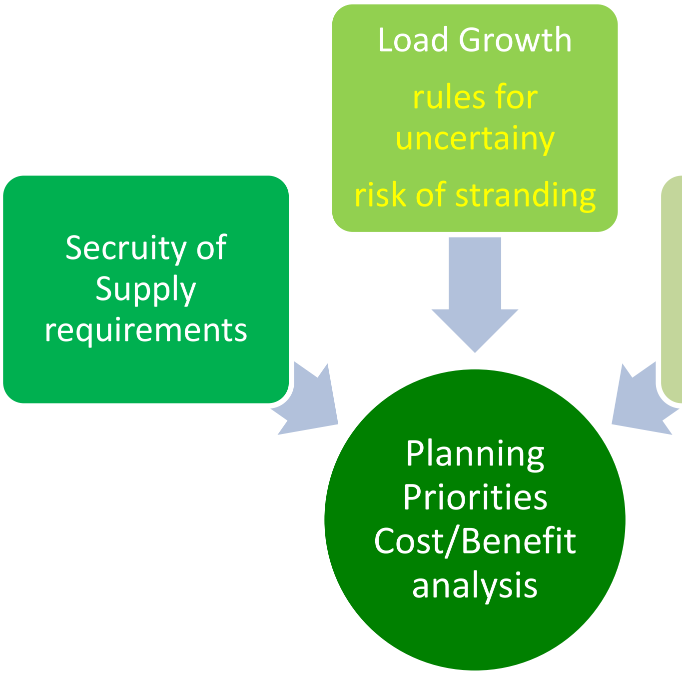
To ensure a structured decision making process, the AHP is applied to all of our CAPEX projects. Table 5.20 over page, describes the areas of planning for which criteria are developed.

Table 5.20 Area of planning risk assessment criteria are developed for

Area of planning criteria are developed for.	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)

Figure 5.12 below, shows the incorporation of the AHP (Risk Policy Matrix) into the planning process.

Figure 5.12 Planning process incorporating the AHP (risk policy matrix)



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6 Life Cycle Asset Management Planning

6.1 Introduction

All physical assets have a lifecycle and electricity assets are no exception. This section describes how assets are managed over the entire lifecycle from conception to retirement.

6.2 Maintenance Planning

We manage existing assets against a number of objectives set down in the Statement of Corporate Intent (SCI), which provide a safe, efficient, reliable and cost effective energy delivery system.

Decisions, for example, on the type of distribution transformers which are purchased are important, as they represent a large group of assets. However due to their smaller size and dedicated nature, they typically are sealed for life and do not require regular maintenance, they remain in service and have little effect on the surrounding assets.

It is fair to acknowledge that the majority of assets spend 95% of their life in the 'operational' phase – sitting there humming away delivering electricity—with occasional interruptions for maintenance, up-sizing or renewal.

Zone Substation transformers on the other hand, require a network development plan to account for loading changes over their lifetime. The capacity of the zone substation transformer directly affects the amount of connected load downstream. Zone substation transformers will not necessarily spend all of their life at one substation. Our zone transformers have a movement plan to best utilise their capacity. All of these factors determine the lifecycle management of the zone transformers as well as the part they play in the wider network development.

Maintenance standards are based on manufacturers' recommendations and experience gained from the historical performance of the item of plant or equipment. Where generic problems are identified, standards are revised to change maintenance techniques and/or intervals. The revision and review process is on-going, as there is a continuing need to incorporate new information arising from field experience, and developments in industry best practice. The reviews are mindful of the need to minimise costly, intrusive and frequent maintenance. However, switchgear and protection devices require regular routine inspection, testing and maintenance to ensure that deterioration or failure of components do not go undetected and untreated. Failure of these types of devices may lead to unsafe conditions for the network.

Notwithstanding the above observations, modern switchgear of certain types are now designed and manufactured to be largely maintenance free for life. Modern protection relays contain self-diagnostics functions to warn of problems via supervisory circuits. These developments influence maintenance plans as well as selection of equipment when refurbishment and renewal is required.

The present age and condition of the asset in conjunction with its service level against service target determines where a particular component fits into the asset lifecycle.

Replacement, renewal and capital works are established from network design practices, which determine the prescribed material strengths, configuration and installation requirements.

Operational procedures form the guidelines for field and system control staff who, during daily events such as planned or fault restoration, operate the assets to maintain a safe, secure a reliable supply.

Regular condition testing is used to monitor equipment or insulating media and provide advanced warning of problems. Increasing use is being made of non-invasive testing techniques, to establish equipment condition profiles, as these become more readily available, and cost effective.

Where non-conformance is detected, procedures dictate the safe isolation, removal and disposal of contaminants.

Economic efficiency is an important driver for maintenance and development work. A large proportion of repair work, refurbishment, and asset replacements are undertaken after economic analysis to determine the most cost-effective solution. This frequently involves the choice between a development option and continued maintenance.

The recent network growth has constrained a number of 11 kV feeders leading to consideration of larger sized conductors to deliver required supply quality. Presently costs to replace poles to support larger loads with heavier conductors are not as economic as installing voltage regulators and/or capacitors in a number of strategic positions.

A full economic cost benefit analysis is undertaken on all major projects ($100,000+), with less rigorous analysis for smaller projects. Some projects can also be justified by other considerations such as safety or statutory requirements.

6.2.1 Linking Strategic Objectives to Life Cycle Management

Summarising the above discussion, the main planning criteria and assumptions for life cycle management of the network assets are below (in approximate order of priority). Specific priorities may vary according to plant type and circumstances.

- 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/manufacturer's 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.

Four main objectives may be identified from the goals and strategies of the corporate intent that directly influence lifecycle asset management. These are: Safety, Efficiency, Reliability, and Economy.

Table 6.1 below, illustrates the linkages between these objectives of the SCI and the planning criteria and assumptions (listed in approximate order of priority).

Table 6.1 Linkage between the SCI and planning criteria and assumptions

Criteria	Safety	Efficiency	Reliability	Economy
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 Lifecycles

The lifecycle of existing assets is outlined in Figure 6.1 over page and is defined in subsequent sections.

Figure 6.1 Asset lifecycle

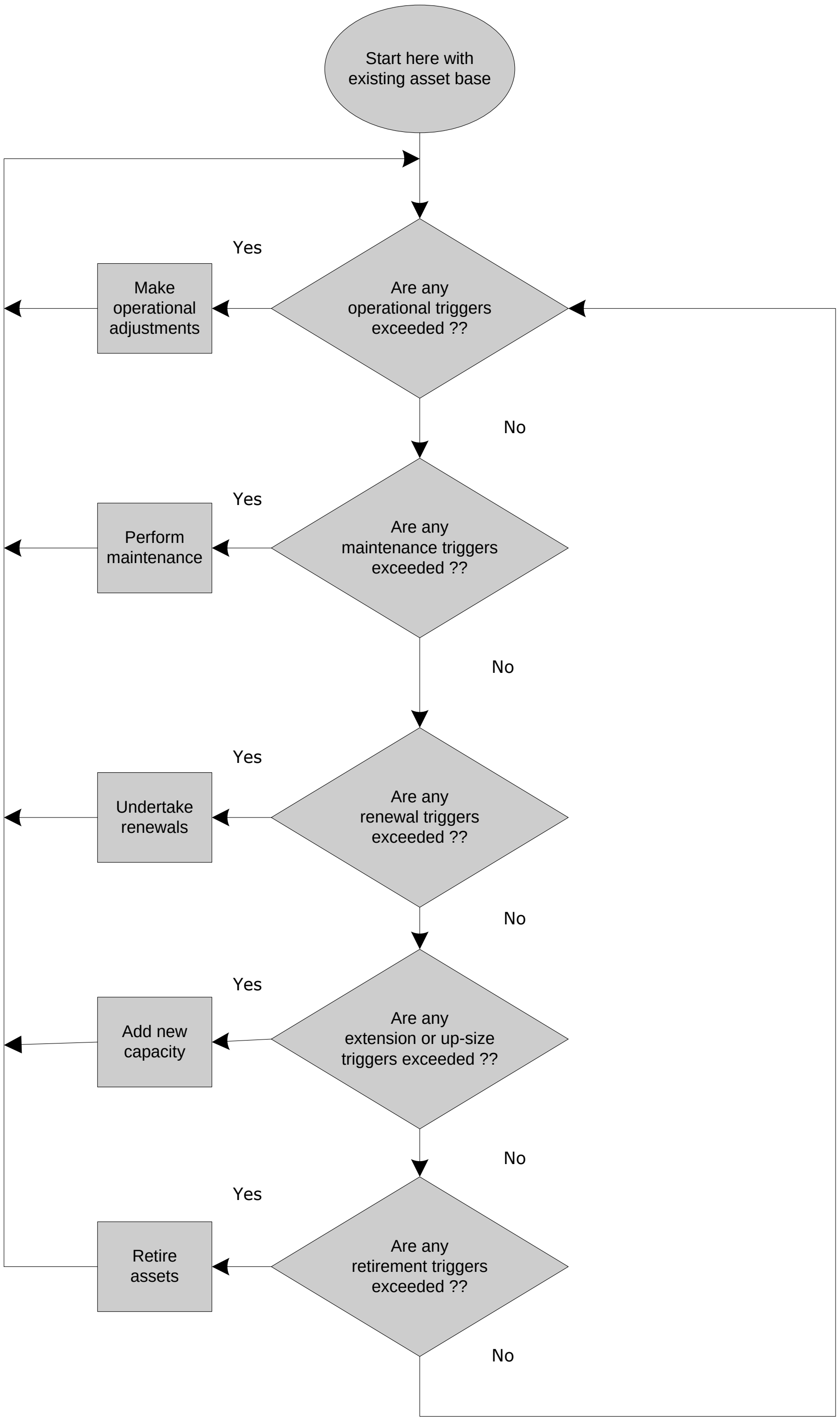


Table 6.2 over page, provides definitions for our key lifecycle activities. Please note that the 2012 Information Disclosure Determination created new OPEX categories, which are described in the table along with the relevant asset management activity that the new category corresponds to.

Table 6.2 Definition of key lifecycle 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 such as 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 assets 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 mile-stone 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.
	Up-sizing (Up-grading)	Generally involves replacing a non-consumable item like a conductor, busbar or transformer with a similar item of greater capacity, but which does not increase the network footprint (ie restricted to Quadrants 1 and 2 in Figure 5.1).
Capex	Extensions	Involves building a new asset where none previously existed because a location trigger in Table 5.2 has been exceeded eg building several spans of line to connect a new subdivision to an existing line. This activity falls within Quadrants 3 and 4 of Figure 5.1 because it extends the network footprint. 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 outlined in Table 6.2 above operations do not involve making physical changes to the network. Operations role is to configure switching (connectivity) and simply letting the electricity flow from the GXP's to consumers' premises year–after–year. Operations will occasionally intervene when a trigger point is exceeded, however the workload of routine switching operations and arising from tens of thousands of trigger points is substantial enough to merit a dedicated control room.

As outlined in Figure 6.1 at page 163 the first efforts to relieve excursions beyond trigger points are operational activities and generally include the activities set out in Table 6.3 below.

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 CB's 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 CB's 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 ABS's	Component current rating exceeded	Open and close CBs, reclosers and ABS's to shift load	Proactive or reactive
	Fault has occurred	Open and close CBs, reclosers and ABS's 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 below, outlines the key operational triggers for each class of our assets. 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.

Table 6.4 Operational triggers

Asset category	Voltage trigger	Demand trigger	Temperature trigger
LV lines and cables	Voltage routinely drops too low to maintain at least 0.94pu at consumers point of supply Voltage routinely rises too high to maintain no more than 1.06pu 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 0.94pu at consumers switchboards Voltage routinely rises too high to maintain no more than 1.06pu at consumers switchboards	Load routinely exceeds rating where MDI's 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 0.94pu at consumers switchboards Voltage routinely rises too high to maintain no more than 1.06pu 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

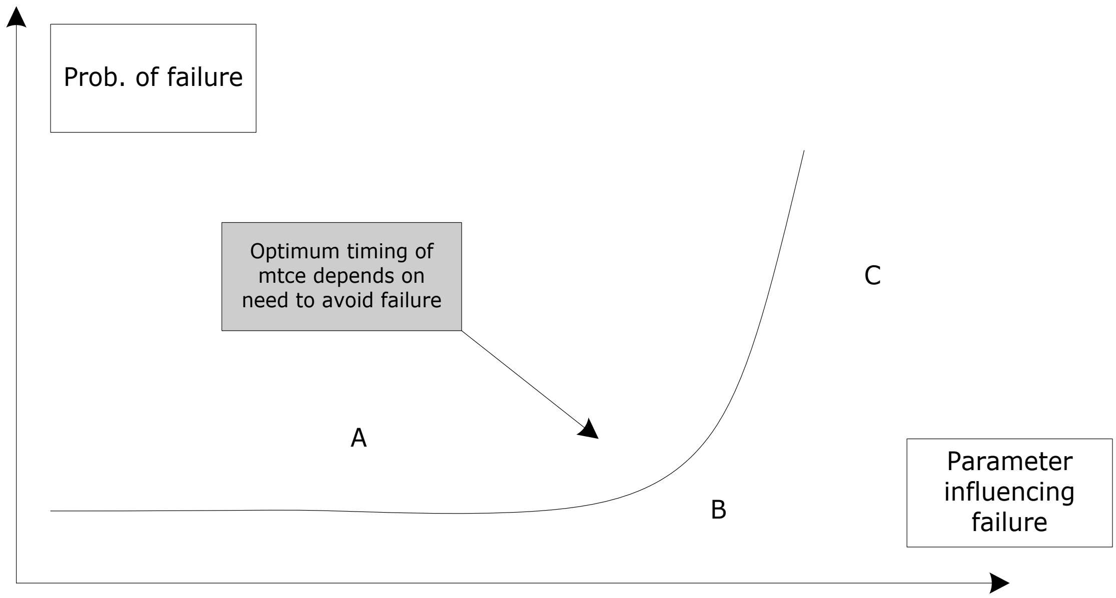
6.3.2 Maintaining the Assets and Systemic Failure Identification

Maintenance is primarily about repairing or replacing faulty or deteriorating components. However, maintenance in its widest sense also includes for the regular inspection and condition monitoring of the assets for detection and recording of gradual deterioration of components and any possible systemic or type faults, and the minor maintenance associated with these inspections, such as cleaning and 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 either installed outdoors or in buildings or enclosures which are outdoors and that are subject to environmental conditions. Major, or full, routine maintenance interventions off-line are necessary to examine asset components that cannot otherwise be inspected or monitored.

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 below.

Figure 6.2 Component failure



Failure of such 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

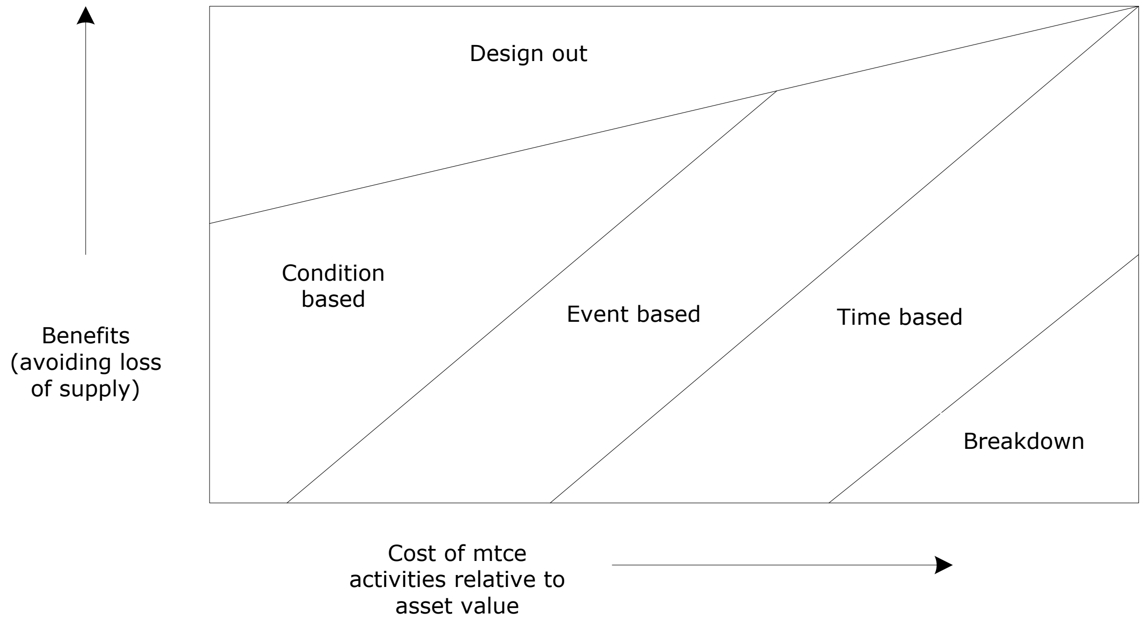
- age
- operating hours
- number of operations
- loading cycle
- stress to components due to fault current or over–voltage events
- ambient temperature
- previous maintenance history
- the presence of contaminants

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

Exactly when maintenance is performed will be determined by the need to avoid failure. For instance, the need to avoid failure of a 15 kVA transformer supplying a single consumer is low, hence it might be operated out to point C whilst a 33/11 kV substation transformer may only be operated to point B due to a higher need to avoid failure. In the extreme case of, for example, turbine blades in an aircraft engine, it would be desirable to avoid even the slightest probability of failure, so the blades may only be operated to point A. Modern protection relays and battery systems in zone substation are critical to the safe and reliable operation of the network and may only be operated to point A. The obvious trade-off with avoiding failure is the increased cost of labour and consumables over the assets lifecycle along with the cost of discarding unused component life. There is a fixed maintenance cost associated with regular monitoring of the condition of the assets and then protecting their components while they remain in service – an operational maintenance cost.

Like all other business decisions, maintenance decisions are made on safety and cost-benefit criteria. The principal benefits are avoiding hazardous conditions and supply interruptions. The practical effect of this is that all assets which have a safety risk associated with them and assets that supply large customers or large numbers of customers will be 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, will more than likely be run to breakdown. The maintenance strategy map in Figure 6.3 over page, broadly identifies the maintenance strategy adopted for various ratios of costs and benefits.

Figure 6.3 Maintenance strategy map



This map indicates that where the benefits are low (principally there is little need to avoid loss of supply) and the costs of maintenance are relatively high an asset should be run to breakdown. As the value of an asset and the need to avoid loss of supply both increase, we rely less and less on easily observable proxies for actual condition (such as calendar age, running hours or number of trips) and more and more on actual component condition (through such means as DGA 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 the maintenance of the safe condition of assets, such as ground mounted LV distribution boxes, which might fall into the 'run to breakdown' area if it were not for the risk to public safety.

As mentioned earlier, condition assessment requires regular and routine maintenance inspections and testing of the assets concerned. 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 resulting in 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 over page, 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.
Distribution substations	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 Excessive rust Broken or damaged hinges or cover fixings.

Asset category	Components	Maintenance trigger
Distribution lines and cables		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.
	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.
	Bus work and conductors	Insulars chipped or cracked. Burn or tracking marks. Thermographic evidence of unusual heating of components and/or connections.

Asset category	Components	Maintenance trigger
		Loose droppers, hot connectors Earthing not intact and connected Birds' nests.
	33 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. 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.

Asset category	Components	Maintenance trigger
		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 and work plans. An outline of our maintenance policies and work plans is given in section 6.9.1 Maintenance Policies at page 182 and section 6.9.2 Maintenance Work Plans at page 183.

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

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
Zone substation transformers (Continued)	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

Asset class	Trigger	Response to trigger	Approach
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 5 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 5 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
	Controller batteries' age	Replace batteries as per manufacturer's manual	Maintenance cycle to suit batteries' replacement
Distribution ABS's	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
Distribution transformers (Continued)	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 remove 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

Asset class	Trigger	Response to trigger	Approach
	Chipped or broken bushings	Replace	Breakdown or condition as revealed by three yearly inspection
	Enclosures (for ground mounted dist subs) •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 6-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
LV Distribution and Link Boxes	Visible rust or corrosion	Repair or replace affected component	Condition as revealed by 5-yearly inspection
	Broken or damaged hinges or cover fixings	Repair or replace affected component	Condition as revealed by 5-yearly inspection
	Cracked or worn fibreglass/plastic	Repair or replace affected component	Condition as revealed by 5-yearly inspection
	Cracked or broken concrete	Repair or replace affected component	Condition as revealed by 5-yearly inspection
	Thermographic evidence of unusual heating of components and/or connections	Repair or replace affected component	Condition as revealed by 5-yearly inspection

6.4 Renewing Assets

We classify work as renewal if there is no change (usually an increase) in functionality ie the output of any asset doesn’t change. Figure 6.4 over page, shows wooden poles being renewed with concrete poles. A key criteria 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 to be carried out is excessive and could be significantly reduced if the asset were renewed.
- Maintenance costs begin to accelerate away; for example, a transformer needs more frequent oil treatment as windings and insulating paper reaches 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 requiring regular and fault operation related oil changes and contact servicing.
- Supply interruptions due to component failure become excessive (and what constitutes 'excessive' will be a matter of judgment which will include the number and nature of customers affected).
- Renewal costs decline, particular where costs of new technologies for assets like SCADA decrease by several fold.

Figure 6.4 Replacing poles

6.4.1 Refurbishment:

Refurbishment involves the replacement of individual components, and is designed to extend the life of the asset. 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. Refurbishment is an integral part of the CAPEX program.

The remaining life of line assets appears to be reducing which indicates that CAPEX will need to increase in future years and in particular the 15–20 year planning horizon to meet the larger population which will require asset replacement at this time.

6.4.2 Renewal triggers:

Table 6.7 below, list 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
	Pins, insulators and binders	Condition based replacement
	Conductor	Condition based replacement
	LV distribution/link boxes	Condition based replacement
Distribution substations	Poles, arms and bolts	Condition based replacement
	Enclosures	Condition based replacement
	Transformer	Condition based replacement
	Switches and fuses	Condition based replacement
	Cable terminations, joints	Condition based replacement
	Ringmain switches, and so on	Condition based replacement
	Reclosers, Sectionalisers	Condition based replacement Controller batteries by age or condition, whichever is sooner
	Regulators	Condition based replacement or maintenance costs exceed replacement Controller batteries by age or condition, whichever is

Asset category	Components	Renewal trigger
		sooner
	Poles, arms, stays and bolts	Condition based replacement
	Pins, insulators and binders	Condition based replacement
	Conductor	Condition based replacement
	Cable terminations, potheads, joints	Condition or age based replacement
Zone substations	Fences and enclosures	Condition based replacement or maintenance costs exceed replacement
	Buildings	Maintenance costs exceed replacement
	Bus work and conductors	Condition based replacement or maintenance costs exceed replacement
	33 kV switchgear	Condition based replacement or maintenance costs exceed replacement
	Transformer	Condition based replacement or maintenance costs exceed replacement
	11 kV switchgear	Condition based replacement or maintenance costs exceed replacement
	Cable terminations, cable boxes, joints	Condition or age based replacement
	Batteries and chargers	Age or condition, whichever is sooner
	Instrumentation	Maintenance costs exceed replacement or equipment obsolete or age limit reached
Sub-transmission lines and cables	Poles, arms, stays and bolts	Age and condition based replacement
	Pins, insulators and binders	Age and condition based replacement
	Conductor	Age and condition based replacement
	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, condition, or maintenance cost exceeded
Our equipment within GXP		Condition based replacement or maintenance costs exceed replacement or equipment obsolete

Broad policies for renewing all classes of assets are:

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

6.5 Up-Sizing or Extending Assets

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

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.	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 customer contribution
Means of cost recovery	Most likely to be spread across all customers as part of on-going line charges	Could be recovered from customers connected to that extension by way of capital contribution
Nature of work carried out	Replacement of components with greater capacity items	Construction of new assets

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 long-term stranding.
- Minimise corporate risk exposure commensurate with other goals.
- Maximise operational flexibility.
- Maximise the fit with soft organisational capabilities such as engineering and operational expertise and vendor support.
- Comply with sensible environmental and public safety requirements.

Given the fairly simple nature of our network, standardised designs are generally adopted for all asset classes with minor site-specific alterations. These designs, however, will represent the wisdom and experience of 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

Although enhancing reliability does not neatly fit into the life-cycle model, we believe that enhancing reliability is strategically significant enough in reshaping the business platform to merit inclusion in the AMP. As described in section 4.4 consumers' prefer to receive about the same reliability in return for paying about the same line charges, so it is acknowledged that there is no mandate to improve reliability just because it can be improved, even if we don't need to increase line charges to do it. However there are many factors that will lead to a decline in reliability over time:

- Tree re-growth.
- Declining asset condition (especially in coastal marine areas).
- Extensions to the network that increase its exposure to trees and weather.
- Increased consumer numbers that increase the lost consumer-minutes for a given fault.
- Installation of consumer requested asset alterations that increase risk of less reliability.
- Predicted increases in frequency and magnitude of extreme weather conditions due to climate change that would increase the risk of less 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 because it tends to be driven more by the need to beautify areas rather than for asset-related reasons (which doesn't usually fit the criteria for renewal or up-sizing). As such, conversion tends to rely on other utilities cost sharing.

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.

Also, if renewal or up-sizing of existing overhead equipment is called for due to activation of the appropriate triggers, placing the new equipment 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 switchrooms may be preferred.

In addition, 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 these reasons of safety and maintenance access before their condition or age indicates that they need renewal or upgrading.

The Christchurch Earthquakes in 2010-11 have high–lighted the risk of damage to underground cables by a serious earthquake. The experience of Orion will be studied with considerable interest with due reference to the probability of an earthquake of similar magnitude occurring in the South Canterbury area. Future AMPs will address this issue in more detail.

In terms of the apparent competing risks of weather verses earthquake upon our network assets when considering the merits of overhead verses underground solutions, the AMP will be considering the relative risks to these two network build options. In this regard, we will be using the engineering definition of Risk as the product of the Probability of the Event and the Consequences of that Event (ie 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 and future discussion of this topic in the AMP will be undertaken in Section 6.13.1 Risk Management.

6.8 Retiring Assets

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

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

Key criteria for retiring an asset include:

- Its physical presence is no longer required (usually because a customer has reduced or ceased demand).
- It creates an unacceptable risk exposure, either because its inherent risks have increased over time or because emerging trends of safe exposure levels are declining. Assets retired for safety reasons will not be re-deployed or sold for re-use.
- Where better options exist to create similar outcomes (eg replacing lubricated bearings with high-impact nylon bushes) and there are no suitable opportunities for re-deployment.
- Where an asset has been up-sized and no suitable opportunities exist for re-deployment.

6.9 Routine and Preventive Inspection, Maintenance and Performance Programmes

6.9.1 Maintenance Policies

Maintenance strategies are based on careful monitoring of an assets condition. Maintenance work comprises 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.

Objective defect criteria for condition based assessments continue to be developed. It is essential that careful consideration be 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 (eg 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 (eg 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 in order to restore service. This work may or may not involve permanent repair of the faulted equipment, 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, which 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 calendar life retirement because they are replaced to increase capacity with new assets. This can defer the need for maintenance.

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 Department raises a new set of maintenance jobs each financial year from within our financial and asset management systems to allow purchase orders to be issued through the year to cover the maintenance work undertaken by our contractors.

The Asset Department 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 over page, lists the three dimensions of control and the jobs associated with each dimension.

Table 6.9 The three dimensions of control and the 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 equipment type, eg distribution boxes • monthly checks • Six monthly or annual inspection and minor maintenance • full maintenance periodicity defined by equipment requirements

There are also specific jobs included in the annual set. This is for overall scheduled maintenance planning and the associated analysis of equipment maintenance records, condition assessment reports, and other maintenance related asset data.

The contractors' scheduled maintenance work plans include for routine visits to asset equipment 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 as required.

Corrective maintenance or refurbishments are triggered by inspections revealing that the condition of the equipment is below standard.

Scheduled work is included in Table 6.10 over page.

Table 6.10 Scheduled work

Asset Type	Description of scheduled work
Zone substations	Monthly checks and cleaning. Annual checks and minor maintenance and outline maintenance programs with periods and actions generally as specified by suppliers of the equipment or determined from experience or local conditions.
Distribution substations: ground mounted, underground and 2 pole	Six monthly checks and minor maintenance include: routine equipment maintenance programs, and special checks and maintenance (such as after heavy rain for underground subs).
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 equipment, and oil sample tests for transformers).

Unscheduled work includes

- inspections
- testing
- repairs or replacement of equipment, for:
  - reported damage or deterioration
  - system fault damage
  - equipment failure
  - environmental effects,, and so on.

6.9.2.1 Zone Substations, Ground Mounted Substations and Switchgear:

We have engaged Netcon Limited (our wholly owned contractor) to prepare, maintain, and execute a comprehensive routine maintenance programme for all our zone substations; ground mounted, underground and two-pole distribution substations; and HV 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 of equipment to the contractor’s workshop. Usually maintenance is undertaken on site if at all possible. If appropriate, routine maintenance may also be undertaken earlier than scheduled while the equipment is out of service for the urgent work, and the date of the next routine maintenance rescheduled.

6.9.2.2 Overhead Lines and Associated Pole Mounted Equipment

In addition, Netcon undertakes overhead line patrols, pole inspections and line maintenance of our 33 kV, 11 kV and LV 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 equipment.

This programme aims 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 Timaru 11 kV sub-transmission cables interconnecting the Timaru GXP and Grasmere St, North St, and Hunt St substations have been undertaken every two years, beginning in 2006. The results of the tests are compared with previous results to identify any deterioration. The new mappings of these important cables and their comparison with the earlier tests provides valuable asset condition information, particularly the state of the 11 kV cable joints.

Two new 11 kV sub-transmission cables (cables 33 kV rated for possible future 33 kV GXP) 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 switchboards and outdoor ground mounted 11 kV switchgear. The tests are generally undertaken biennially with more frequent tests for equipment that has exhibited partial discharge levels requiring closer monitoring. Depending upon the nature of these partial discharge levels these repeat tests may be undertaken at six, 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 for Hotspots on Outdoor or Exposed Insulators, Joints Contacts, and Fittings

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

Services provided by Netcon for AELs maintenance programme.

Table 6.11 over page, 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 buildings, kiosks, padmounts and enclosures – five yearly cycle, as part of overall condition assessment
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. sub buildings, kiosks, padmounts and enclosures – 15 yearly cycle
Civil type maintenance includes any non-electrical work not requiring an access permit, outside of the MAD,	buildings, fences, enclosures, kiosks, external surfaces of padmount subs,, and so on. yard maintenance and weed control concreting and carpentry work cleaning, rust removal/treatment, and painting

6.9.3 Defect Identification Processes

Our maintenance is undertaken by contractors, mainly Netcon, who undertake regular scheduled maintenance inspections to determine the condition of the network equipment 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 of the unsafe condition and receiving appropriate permits, operating instructions, and clearances.

Routine maintenance visits are scheduled to substations and equipment sites based on manufacturer’s recommendations, best industry practice and field experience for the equipment concerned. The contractor submits reports to us containing 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 upon 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.

Also, we have begun an 18 month detailed condition assessment inspection programme (from mid-2009) of all LV ground mounted distribution boxes and link boxes. This project uses a contractor equipped with a handheld data entry touch screen storage device allowing daily down loading of the collected condition data into a database. While the programme has had some delays, it was due for completion of the assessment phase in 2013.

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 found. The actions may be organised according to geographical area or particular type of defect correction in order to optimise the maintenance resources to be expended. 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 either fixed immediately by the contractor while on site, or referred immediately to us for immediate reactive attention.

A similar detailed condition assessment project was launched in November 2010 for HV/LV distribution substations. The condition assessment of all ground mounted and 2-pole substations (of 100 kVA or greater) was completed in May 2011. The 30 quantity underground distribution substations in the Timaru CBD are still to be done.

A special one-off set of PD mapping tests 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 last 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 joint 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.

6.9.3.2 Distinguishing Features between Regular Maintenance Visits and Special Condition Assessment Inspections

The difference between routine maintenance visits, and special detailed condition assessment inspections, is the much greater level of detail checked and use of automation devices for data collection and retrieval associated with the latter.

The data collection method for detailed condition assessment is similar to that previously used for recording the pole position and basic site data when setting up the GIS database. The difference between this previous GIS data collection and the present condition assessment projects is the increased level of technical and condition data being collected in the present condition assessment case.

6.9.3.3 Future Maintenance Data Collection Methods

Ultimately we envisage that the contractor will use this same method of detailed data collection and condition assessment during their routine maintenance inspections.

However, before this can be initiated, we need to update its present legacy asset databases and asset management systems to enable this automated data collection method to be used efficiently and effectively and to permit the collected data to be usefully processed, analysed, and results utilized. This will also involve developing linkages between our proposed new, integrated, asset database and management system and the contractor's systems.

6.9.4 Serious Defect Rectification Process

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

- safety risk to the public or employees, or
- danger to continuity of supply, or
- risk of damage to Network equipment.

Please note operations would be notified of the defect immediately it is discovered or immediately after the corrective action, depending upon the nature and urgency of the corrective action required and the need for any network access or permissions required before action can be taken.

Minor defects may also be dealt with directly without immediate reference to us.

In both the above cases the defects and maintenance actions would be reported to our asset department after the action to confirm our approval and allow us to issue a maintenance order, as appropriate, to cover the actions taken.

Defects outside of either 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, or
- scheduling for subsequent routine maintenance visits, or
- initiation of a special project whose nature would depend upon the type, size, and seriousness of the defect.

6.9.5 Routine Maintenance System

Table 6.12 below, 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 equipment in accordance with the equipment suppliers' recommendations	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 equipment suppliers' recommendations	Five yearly when RMU present; every 15 years when no RMU present
Sub-transmission cables	Partial discharge mapping	Biennially
Timaru 11 kV Sub-transmission switchboards (Grasmere St, Hunt St, and North St)	Partial discharge tests	Annually, for the older switchgear (Hunt St), 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

Asset Class	Routine Maintenance Type	Frequency
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 HV switches (recloser, sectionalisers)	Inspection and earth test. Minor in situ maintenance	Annually
Pole mounted HV switches (recloser, sectionalisers)	Full maintenance	Five to 10 yearly, or more frequently if manufacturer, condition or age demands
Regulators	Yearly inspection and clean. Minor in situ maintenance, including battery system, software, earthing checks	Annually
Regulators	Full maintenance including oil and operational tests; and associated equipment. Corrosion treatment and water proofing	Five yearly, or more frequently if specified by supplier
Capacitors (11 kV line regulation type)	Inspect and test capacitance, check fuses; and maintain associated equipment	Five yearly, or more frequently if specified by supplier
Pole lines, including associated overhead fittings and equipment.	All lines older than 25 years (or younger if condition dictates), inspection of poles, line fittings, conductors, disconnectors, fuses, and so on.	10 yearly, with scheduling based upon age and condition

Upon receipt of all new equipment, Netcon undertakes a close inspection of the item and makes any necessary additions or modifications to the protective coatings and water sealing that the particular type or make of equipment may require to better resist the environment where it is to be installed. This is to reduce ongoing maintenance and extend the life of the item.

6.10 Maintenance Plans for the Next 12 Months

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

6.10.1 Sub-transmission Lines and Cables

This sub-section discusses our maintenance plans for sub-transmission lines and cables.

The 2014/15 budget for annual expenditure on sub-transmission lines and cables OPEX maintenance is $46,000 per annum.

The fourteen 33 kV sub-transmission lines and cables are the highest priority as they have the largest impact on network reliability should they become unavailable. Sub-transmission lines are built to the highest standard of resilience and in the cases of Clandeboye and Pareora 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 Timaru GXP to Timaru CBD zone substations were augmented in 2011/12 by two new 33 kV cables that are operated at 11 kV between Timaru 11 kV GXP and the new North St Substation. Should a 33 kV GXP be introduced at Timaru 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.

(Note: The new 110 kV double circuit line from Bell's Pond Substation to the new Cooney's Road zone substation will be commissioned in 2014 and initially run at 33 kV with both circuits paralleled. Once commissioned in 2014, this new line will be added to the sub-transmission lines and cables maintenance programme).

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

Table 6.13 Sub-transmission line inspection priority

Location of line	Year of Construction	Maintenance Priority
Timaru Sub to Pareora Sub #1	1979 and 1985	1
Timaru Sub to Pareora Sub #2	1963	2
Timaru Sub to Pleasant Point Sub	1977	3
Temuka Sub to Geraldine Sub	1966	4
Temuka Sub to Winchester Township	1979	5
Winchester Township to Rangitata Sub	2003	12
Temuka Sub to Clandeboye Sub	1997	10
Albury Sub to Fairlie Sub	1967	6
Opuha Dam to Fairlie Sub	1997	7
Tekapo Sub to Mt Cook Sub	between 1975 and 2001	8 and 11
Transpower Tekapo to Tekapo Sub	1991	9
Transpower Twizel to Twizel Sub	1968	7
Canal Rd CB to Rangitata Sub	2010	13

6.10.2 Zone Substations

The 2014/15 budget for annual expenditure on zone substation OPEX maintenance is $474,000 per annum.

Expenditure for power transformer maintenance and repair work was higher than average over the last five years due to cases of gassing in power transformers, and other major maintenance, due to the aging nature of the power transformer population. The first case of gassing in the Albury 7 MVA step-up transformer was repaired under warranty in Australia (in 2009/10) but transport and local costs were covered under OPEX. The second case (in 2011) involved removing the 20 MVA Clandeboye No.1 T2 33/11 kV transformer to Palmerston North for tests, major refurbishment, and repairs, all an OPEX cost.

Prior to 2008, the Pleasant Point, Geraldine, and Rangitata transformers had received major maintenance with de-tanking, core dried out and oil renewed to ensure the units reach end of life as part of refurbishment. The Mt Cook transformer was painted only. These substations are typically single bank sites, so reliability of the unit is important as there is no second unit to retain supply should the primary unit become unavailable for service.

All zone substation equipment is routinely inspected, and serviced on a six monthly inspection cycle. Zone substations are visited on a monthly cycle for cleaning and routine visual inspections, including switchgear, protection, instrumentation and monitoring readings of temp, tap change operations, breaker operations, protection flag resets, battery charger status and maximum demand indicators.

Unplanned visits can include the situation where a feeder fault operates a substation circuit breaker, requiring an operator to attend to review and reset flags before commencing restoration procedures.

Better standards are being developed based on approaches adopted from Transpower Maintenance contracts.

Regular zone substation inspections also include buildings and equipment with as well fire protection and security systems. Work covered on the buildings includes clearing of gutters, and other general work. 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, 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 every ten years approximately. 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 life.

Similarly the Albury zone sub-transformer (as mentioned above) had a gassing problem which required oil treatment. This unit was changed out temporarily and removed from service and returned to the manufacturer for repair. This unit returned from the manufacturer after repairs that included new windings, repainted tank and other improvements. It was reinstalled at Albury Sub in March 2010.

In 2012/13, the two ex-Pareora zone substation 5/6.25 MVA OLTC transformers were refurbished under the CAPEX budget and are now destined for Fairlie and Tekapo.

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 ten 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 will not become 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 2010 during a Transpower outage at Twizel, the Twizel Substation 33 kV and 11 kV structures were extensively inspected, fasteners tightened, and some components replaced. Maintenance on other equipment 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 necessity for frequent testing of this equipment. The older electromechanical protection relays however will still require frequent testing and adjustment. During the Twizel substation shutdown referred to above, a renewal of the transformer REF and EF protection was undertaken due to the poor condition of the original protection equipment. The power transformer was upgraded at the same time because of load growth.

A CAPEX project in 2011 associated with the new North St substation (replacing Victoria St substation) included replacement of aged protection equipment in Hunt St and Grasmere St substations.

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 on-going, 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 2014/15 combined annual OPEX maintenance budget for network lines and cable maintenance (LV, distribution, and sub-transmission) is $3,613,000. This is split approximately $328k for LV lines and cables, $3,239k for distribution lines and cables, and $46k for sub-transmission lines and cables (these amounts do not include renewal and upgrade expenditures which are in the CAPEX budget).

The 11 kV distribution lines and cables are typically open ringed in the city areas to afford supply security for the densely populated areas and arranged as single spur lines in the rural areas. Increasingly, in the higher load density rural areas (eg irrigation and dairy areas), rural lines are also being 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 prudent levels.

Areas reticulated with predominately concrete poles from early 1960's to late 1970's have, to date, only been maintained 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. There are very few concrete pole replacements expected due to old age.

Concrete poles have an estimated life of 60 to 120 years while hardwood poles have a life of 40 to 60 years. Hardwood poles are an on-going maintenance concern, as they will eventually rot below ground level. With the population of hardwood poles, 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, pole age based on line installation date is a poor indicator of reliability, as pole condition assessment is used to determine how an existing asset is to be managed.

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 their 25th birthday and a closer inspection frequency towards end of life. This will be discussed and monitored closely in conjunction with other networks that have experienced similar problems in the past few years. Due to the poor performance of softwood poles and some premature failures they will be closely monitored with a view to ceasing their 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. To offset the effects of this significant increase, some work has been programmed forward.

The refurbishment program involves replacing the failing original poles with new concrete or new wood 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 a review of tree growth threatening the line security. 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. A dedicated database has been developed to administer tree management and notification processes moving forward.

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 ten-year basis, covering 10% of the route length per year. Where there is an identified condition problem, a more in depth analysis and solution is derived. 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.

Areas predominately reticulated with hardwood poles between 1955 and 1961 have been inspected every ten years, and replaced as required, since 1985. 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. During inspection the aim is to identify and document all components that may not be capable of supporting design loads for another ten years and compliance with clearances in ECP34.

Each timber pole is visually inspected above ground 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. An industry standard Red Tag which indicates pole replacement within three months of inspection for poles at risk of failure under normal structural loads. A Network 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 5 years and maintenance as require by normal condition assessments.

However, as a relatively high level of urgent reactive maintenance actions were necessary during 2009-10, a special condition survey was initiated of all distribution boxes initially for an 18 month period, interruptions in the programme due to pressure of other work has 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 5 year cycle.

6.10.4 Distribution Substations

This category includes 11 kV/415V distribution transformers, 11 kV Ring Main Units (RMUs), pole mounted reclosers, regulators, and voltage correction capacitors.

The 2014/15 annual maintenance budget for distribution substations is $1,083,000 which includes inspection, assessment and repairs. Replacement of significant items, such as transformers and RMUs, will be financed from the CAPEX budget.

Distribution transformers are inspected, and earths tested every ten 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 [16]. For ground mounted distribution substations of 200 kVA or greater, the inspection and maintenance is typically carried out as a targeted separate project in every 5 years. Distribution substations with RMUs, are on a 15 year cycle or until overdue maintenance is caught up. The routine maintenance described here is separate from the special and detailed condition assessment studies referred to elsewhere.

[16] This excludes earth testing for distribution substations.

11 kV RMU oil switches are still being targeted for more detailed maintenance every 5 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.

Equipment 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 Washdyke.

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 2014/15 annual maintenance operations budget is approximately $328k for LV lines and cables (these amounts do not include renewal and upgrade expenditures which are in the capital budget).

6.10.6 SCADA, Communications and Ripple Plants

The 2014/15 maintenance budget for this equipment is set at $177,000 per year.

The present SCADA System Master Station and hardware platform was last replaced in 2006 as the earlier master station had reached the end of its serviceable life and obsolescence of hardware spares. The new system had improved functionality and reliability.

In 2013 the present SCADA System Master Station’s hardware platform was replaced due to the equipment being over its economic life. The hardware replacements were chosen to meet the requirements of future software upgrade needs.

The Master Station software upgrade in 2013/15 will include expansion of the present SCADA System database and software capacity to cater for the increasing number of zone substations, and monitored and controlled points resulting from the present communications upgrade project. Also it will also include a “whole network” view that will allow efficiencies in preparation, updating, and operational use of our network switching diagrams.

A new digital GHz frequency radio system for SCADA System communications is being progressively introduced as Zone Substations added to or upgraded within the AEL Network. These modern substations contain microprocessor based protection and control equipment that use the DNP3 protocol and require modern communications (Refer to Sections 3 and 5 for more details).

The legacy UHF analogue radio system has reached end-of-life determined by equipment age, reduced support from manufacturers, and obsolescence of legacy technology that is now replaced by microprocessor controlled technology. The legacy base station and repeater assets 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-three years.

Equipment failures are normally of a random 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 an antennae. Recent severe winter conditions highlight 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 equipment. Typically electronic equipment reaches technical obsolescence in five - ten years although generally the equipment can be supported in service for 10-15–years. A number of analogue radio systems will require replacement within the next two - four years.

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

The integrity of the SCADA System hardware and software systems is of the highest importance to the on-going 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.

RTU replacement is currently being undertaken over a 3–year period due to obsolescence of the present equipment. Similarly, as mentioned above, the legacy UHF analogue radio equipment has reached the end of its serviceable life and will be replaced within the planning period.

The ripple injection system is gradually being updated, with the old rotary injection installations 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 5.7.

6.10.6.1 Communications and SCADA System Equipment Room

An independent consultants report was commissioned in 2009 to advise on the state and recommended upgrade path for the existing Communications and SCADA System Equipment Room at Washdyke Depot.

The report completed in November 2009 confirmed the need for upgrading the equipment 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 had been consider advisable to review the whole SCADA Master Station and communications set-up. This was due to the possibility that the control room, and by extension the equipment room, might be relocated to a proposed new Washdyke zone substation site. In addition, significant upgrades to the capabilities of the Master Station would be required.

It has been decided, in order to maintain adequate SCADA System reliability, to upgrade the SCADA Master Station within a new control room facility within our existing headquarters at Washdyke. This will also enable the equipment room to be upgraded in due course.

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, the network lines and other overhead equipment. The growth of trees and other vegetation appears to have increased of recent years, possibly due to increased availability of water through irrigation and other factors. 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 throughout the network region to keep trees away from existing lines and to clear trees (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 proposed to record vegetation control work. This new database tool would enable the tree maintenance to be correlated with the SAIDI events that are attributed to ‘tree’ causes. It would also allow more accurate budgeting, planning and management of the vegetation control resources.

This proposal will be included within the upgrade to our asset management systems component of the IT review project. In the interim we have created a trees log spread-sheet (January 2013) that will record vegetation request information.

The effectiveness of this spread sheet log will be monitored during the course of the year and will provide data for the planning of the development of the vegetation control section.

As a result of the severe wind storms of 2013, a special programme of removing trees within falling distance of 33 kV sub-transmission lines has been instigated with the support of the local property owners concerned.

6.11 Non-network Assets: Maintenance and Renewal

Non-network assets are those defined by the IDs as being related to the provision of electricity lines service but which are not used directly to provide line services. The IDs provide a list of non-network assets, that are used by us, including a description of use, maintenance and renewal policies are listed in the sections below.

We are developing policies for specific areas of asset management including policies for vehicle maintenance and replacement, IT equipment renewal, and a property maintenance policy.

6.11.1.1 Motor Vehicles

Vehicles are used for a variety roles depending upon the department that uses them. The vehicle fleet includes four wheel drive utility vehicles and station wagons. Figure 6.5 over page shows a typical utility vehicle used by ourselves.

At present vehicle maintenance and renewal is managed using a spreadsheet based algorithm that records distance travelled, age of the vehicle, and licencing requirements, and so on. All vehicles are owned by us and managed by the Training and Compliance Manager. Vehicles replaced every four year on average.

Figure 6.5 A typical example of an AEL utility vehicle

6.11.1.2 Office Buildings

We use a range of buildings to house network assets, (e.g. North St, or Grassmere St substation buildings). These substation buildings are considered network assets.

Non-network asset buildings include the four buildings used to house our engineers, controllers, corporate staff, and so on, which 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 upgrade of the Netcon building in 2014/15.

6.11.1.3 Information Systems

For a description of IT systems specific to asset management please refer to section 0

We pay annual licencing 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 IT requirements.

Day to day IT requirements are supported by our IT department which has dedicated personnel for this task.

IT equipment is managed by the IT Services Manager according to life cycle principles of procurement, maintenance and disposal depending on the user requirements and the most beneficial solution. IT 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 IT related office equipment, including furniture, appliances, and so on., is managed by the Training and Compliance Manager. Equipment is maintained on a case by case basis although all electrical equipment is tag and tested on an annual basis.

New equipment over $500 is approved by department managers and the Corporate Services Manager. This process will be formalised with the introduction of the CAPEX Policy in the 2014/15 year.

6.12 Maintenance (OPEX) Budget Projections

Table 6.14 at page 206, lists the projected maintenance expenditure by asset class for the period 2014/24 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 nonminal terms for the next 10 year period.

In compiling the maintenance expenditure projections the following assumptions were made:

- 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 estimated $1 million to OPEX annual budget under Distribution Line and Cables.
- Maintenance expenditure budget to be held constant in nominal dollars from 2014-15 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 about 2008.
- Reduction in maintenance required overall as newer lower maintenance equipment is 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.

However, caution needs to be exercised as some of the above assumptions of reducing growth of maintenance expenditure may not in fact eventuate should the following occur:

- Increased complexity and size of some of the newer equipment items requiring higher levels of technical attention during routine and reactive maintenance.
- Increased numbers of sites and items of equipment 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 moving from a low maintenance condition into a higher maintenance condition as the plant approaches the end of its life (eg OPEX equipment 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 renewal and major refurbishment and up-sizing (or upgrading). These 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 Section 5 and the totals summarised with respect to four asset categories in this present section. Table 6.15 at page 207 summarises the asset replacement and renewal budgets by asset category for the 2014/24 period in real or constant dollars.

Table 6.14 Maintenance expenditure by asset category

Asset Category	Forecast (in $'000)										
	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
LV Lines and Cables	596	328	328	328	328	328	328	328	328	328	335
Distribution Substations	758	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,083	1,105
Distribution Lines and Cables	3,215	3,239	3,239	3,239	3,239	3,239	3,239	3,239	3,239	3,239	3,304
Zone Substations	818	474	474	474	474	474	474	474	474	474	484
Sub-transmission Lines and Cables	72	46	46	46	46	46	46	46	46	46	47
SCADA and Radio	162	177	177	177	177	177	177	177	177	177	181
Unspecified	1	1	1	1	1	1	1	1	1	1	1
TOTAL	**5,621**	**5,349**	**5,349**	**5,349**	**5,349**	**5,349**	**5,349**	**5,349**	**5,349**	**5,349**	**5,455**

Table 6.15 Asset renewal and refurbishment budgets for 2014/24

Project Category	Forecast (in $'000)									
	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
Sub-transmission, Distribution, and LV Lines and Cables	1,910	2,190	2,970	3,100	3,620	4,700	3,700	3,700	3,700	3,700
Distribution Substations, including transformer, regulators, ring main units, and so on.	850	740	740	652	652	652	652	652	590	470
Zone Substations	1,420	275	225	275	225	150	150	350	200	200
SCADA, Comms, and load control plants	580	500	150	100	100	100	100	100	100	100
Total Asset Replacement and Renewal Projects Expenditure	**4,760**	**3,705**	**4,085**	**4,127**	**4,597**	**5,602**	**4,602**	**4,802**	**4,590**	**4,470**

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 2 years.

For example, we may use smart meters to limit large capital expenditure through control load from Albury and Timaru 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 sites and others will be evaluated.

7 Risk Management

7.1 Introduction

Risk is inherent in all of our business activities, from financial risk to risk to our staff and the public. The AMP however is particularly concerned with risks to our network assets and the risks associated with managing and growing the network. That is risks associated with providing safe, efficient, reliable and cost-effective energy delivery.

Risks to the network include risks to:

- health and safety, including public safety
- reputation
- the environment
- compliance
- finances
- reliability of supply
- security of supply.

We are presently developing a comprehensive risk management register which will provide better consistency for risk management across all avenues of the business and will strengthen the risk management process.

This will support and standardise our risk assessment and mitigation management. Further information on our policy development can be found at section 5.8.2 at page 156.

Our present risk management system includes a 2005 assessment that evaluated major network assets for risk of failure. It also encompasses other risks that are discussed separately in documents such as the Health and Safety Management System and the Emergency Preparedness Plan, with the overall impact of all risks on network assets and activities taken into account by management.

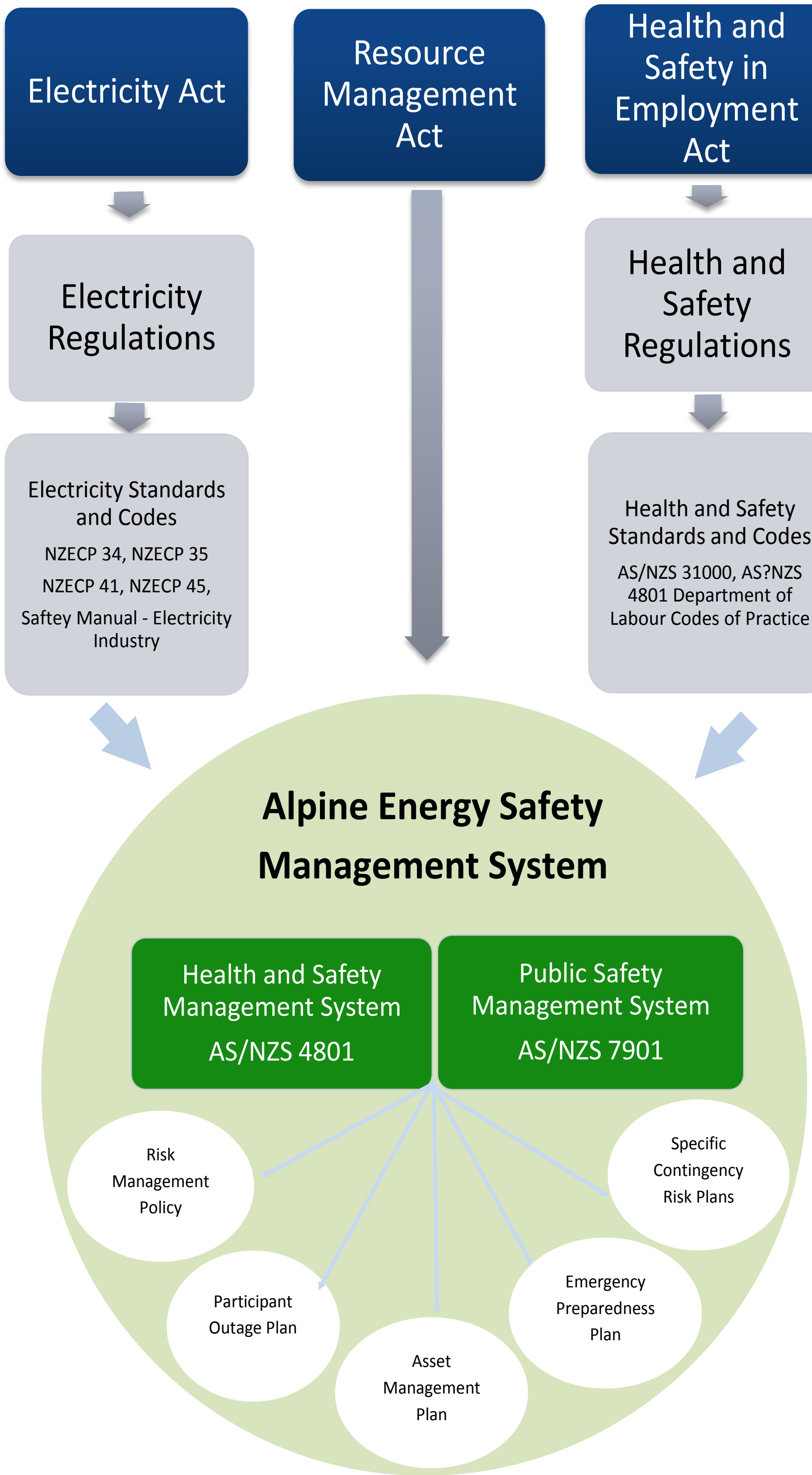
This chapter discusses risk management of network assets and activities based on the 2005 risk assessment as well as discussing other relevant risk management plans used for asset management.

Altogether, elements of the AMP are integrated with our Safety Management System (SMS) as described in Figure 7.1 over page.

7.2 Safety Management System

Our integrated Safety Management System, consists of the Health and Safety Management System, and Public Safety Management System.

Figure 7.1 Safety Management System framework



Our Public Safety Management System is regularly externally audited and complies with the requirements of *NZS7901:2008 Electricity and Gas Industries—Safety Management Systems for Public Safety*, and the requirements of *AS/NZS 4801:2001 Occupational Health and Safety Management Systems*.

The integrated Safety Management System also includes, but is not limited to, the: Asset Management Plan, Emergency Preparedness Plan, Participant Outage Plan, Civil Defence Emergency Management, and 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 property damage to property, from network assets, and the operation of those assets. 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.

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 is to prevent serious harm to employees, contractors and general public or significant property damage to property arising out of our work activities.

7.3 Emergency Response and Contingency Planning

We recognise that the local economy depends on a secure and reliable supply of electricity, and that catastrophic natural events, including earthquakes, landslides, tsunami, floods, wind and snow storms, 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 equipment 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 sister electricity distribution networks – these were last activated during the Christchurch Earthquakes of September 2010 and February 2011, Our contribution was mostly logistical (including re-deployment of Transpower’s 11 kV switchboard to Bromley substation rather than its scheduled home at

Timaru Substation), with some staff being deployed to assist Orion in the field on an 'as requested' basis. An offer was also made of the North St 11 kV switchboard but it was not needed.

The lessons learned from the Christchurch Earthquakes has meant a larger focus on liaising with other essential service utilities, local authorities, emergency services, and major industrial and commercial customers. This has resulted in an improvement to prioritisation of feeders and lines vital to critical infrastructure, and also to formal external notification of unplanned outages.

Our wholly-owned subsidiary contracting company Netcon provides 24 hour 7 day response service (on direction from our controllers) to respond to network outages, and both retailer and individual customer faults.

7.3.1 Business Continuity Planning

Regular electronic backups of mission critical records that are required for billing of retailers or identification of customers are performed. The backup copies are securely stored away from site.

We are currently looking to establish a more encompassing business continuity plan (incorporating the SCADA, GIS and other databases).

7.3.2 Emergency Preparedness Plan

The Emergency Preparedness Plan was completely reviewed and updated in 2011 to ensure compliance with the requirements of NZS 7901:2008 and AS/NZS 4801:2001 and is regularly renewed after each critical event.

It is distributed to our staff as part of our Health and Safety Management System process, this provides staff with procedures to follow for emergency events including but not limited to:

- 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.

7.3.3 Communication

The emphasis on greater communication has extended into pushing more information to stakeholders and the public in a very proactive manner.

Responsibilities for this communication are detailed in section 3.2 of the Participant Outage Plan. These responsibilities are listed below:

- Chief Executive Officer—
  - Information required by the Commerce Commission.
  - Communication with the media, stakeholders and other EDBs and Transpower.
- Corporate services Manager—Communication with general public, general public and retailers.
- Training and Compliance Manager—Communication to Police, Civil Defence, local councils, and other local authorities.

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 or by subscribing to Telephone Video Data (TVD). TVD 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 Commission. With the dissolution of the Electricity Commission this requirement to audit and approve Participant Outage Plans has been passed on by the Electricity Authority to the Transpower System Operator.

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 initial Participant Outage Plan was submitted to the Electricity Authority, and was audited and approved by the Electricity Authority on 31 August 2010. It has subsequently been submitted and approved by the Transpower System Operator.

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 supplies to essential services, and to individual major industrial and commercial customers have been re-developed to complement and supplement the Participant Outage Plan.

An example of this is the contingency plan 'Supply to TMK 33 kV on loss of TIM T5 and T8 (both 220 kV circuits)' which has been 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 RT link is installed in Timaru District Council's Emergency Operations Centre for direct communication with our Control Room.

We were a founding member of the South Canterbury Lifelines Group. This has since been amalgamated with the Canterbury Lifelines Utilities Group. This Group promotes resilience to risks, and develop 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 the Civil Defence regional exercises such as Pandora and lessons learnt from this are used to enhance our current emergency response planning.

This has been put to the test with after-hours activation of emergency plans caused by two tsunami threats to the South Canterbury coastline, and our response to the Christchurch Earthquakes.

7.4 Risk Management Planning for Network Assets

The utility nature of an electricity lines business requires the assessment and management of a variety of risks that have potential to impact on the business and extends across the general public and environment.

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 considered not only by consequence and likelihood but assessed against a third dimension: of controlling of the cost of loss prevention. This recognises, at the utility level, the cost penalty and diminishing returns attained in loss prevention as expenditure is increased.

This recognises that there is a cost–benefit aspect of risk management in the context of electricity distribution. There is an optimum point based on the return gained for the risk dollar, beyond which it would be futile to spend any more money to reduce the specific risk and this money would be better directed 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 as necessary have been modified so that they are within our risk criteria for acceptable risks.

We will therefore assess and treat risk as part of planning and decision making at all levels of the company. To provide consistency and confidence, we shall undertake these risk management activities in accordance with our internal standards that shall reflect best national and international practice.

We will adopt a structured and consistent approach to assess and treat all types of risk, at all levels and for all activities in the company. Our approach to risk management will be consistent with the risk management standard *AS/NZS ISO 31000:2009, Risk management—Principles and guidelines*, and the company's guidelines and procedures 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 or there be a change in circumstances that might enhance or prevent us achieving its purpose and objectives, the organization is able to recognize and respond to the risks in a consistent, proactive way. Equally, when events occur, we will use systematic processes to learn the lessons from its 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 modifying the risks (enhancing or reducing) are in place and are effective at all times, and for ensuring that control assurance activities also are effective.

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:

- establish 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 cost effective distribution system.

This provides a context of 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 it has 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 forms 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 risks is an iterative process and while well–developed, due to experience gained from managing long life assets, new techniques are becoming available for predictive condition assessment that allows proactive risk management.

We are also 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, such as floods, high winds, lightning, snow, earthquake, tidal wave and fire. There are aspects of the selection and installation of network equipment that minimises chlorofluorocarbon gas emissions, oil spills, arc flash exposure, failure of line supports, etc., to mitigate adverse effects to the environment and general public.

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, car vs. pole collisions, illegal access into authorised areas, leaving electric fence wire or other similar conductive materials where the wind or birds may carry up into overhead line.

7.4.2 Risk Analysis

Risk analysis is used to determine the most effective means of treatment. This has a number of dimensions to be satisfied which meets the objectives of our business.

We have undertaken a qualitative assessment of risks that the business faces to determine the ranking of risks that require treatment to reduce their impact to the business. Table 7.1 below provides, 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 over page, 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 4 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 below, combines the qualitative assessment of consequence and likelihood to provide a level of risk matrix.[17]

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.

[17] Our method is based on ISO/IEC 31010.

Risk analysis evaluates the factors affecting the consequences and likelihood and the effectiveness of existing controls and management strategies.

Quantitative analysis is used where specific performance measures are in place, ie 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) equipment through its 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 that traverse the region and support 11 kV equipment and distribution level transformers which break down into the LV networks and some 30,000 customer connection points.

Loss of a high hierarchy asset at the Transpower connection level has a high consequence for disrupting a large number of customers; however is a very low probability event.

Table 7.4 over page, 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 222, 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 the above risk analysis table identifies the loss of a power transformer at a single transformer zone substation as a common high risk. The current system of maintaining a critical system spare lowers the risk to a moderate level. Other procedures of regular oil sampling and major maintenance when a transformer is moved from one location to a new site also provide a level of confidence in lowering the likelihood for failure. However with growing demand on the network, some substation sites do not have full N-1 capacity all year round, which identifies a need to review contingency plans for transformer failure and replacement.

Our mobile sub is expected to be available for deployment by 2014/15.

Previously, protection maloperation at Hunt and North St 11 kV switching stations posed a high risk due to load sharing on remaining cables. Apart from on-going training and familiarisation of protection scheme design, this had highlighted the need for stronger inter-tie cables between these and the Grasmere St substation. The commissioning in 2012 of two new 33 kV cables to be run at 11 kV between the new 11 kV switchboard at Transpower's Timaru GXP and our new North St switching station has enabled this risk to be reduced from High to Moderate.

Bus faults and CB failures only cause a Moderate risk and can be tolerated with provision of existing spares inventory where these are available.

Vandalism has been at a very low level and provided systems of alarm security and security of perimeter fences and locks are well maintained the low risk level is expected to be maintained.

7.4.3.1 Risks to Substation Assets

A high risk level had been identified at Grasmere St and the two Clandeboye substations. The new 11 kV switchboard at Grasmere St, commissioned in March 2013, lowers the risk at that substation as a result of the decommissioning of the old switchboard which had partial discharge issues. The primary consequence is loss of supply to very large commercial operators. Adequate on-going training is provided and only experienced staff are permitted to operate at these sites.

There is an acceptable level of risk from line hardware at substations due to regular maintenance and surveillance systems in place. Provided these are maintained, the risk levels are unlikely to change.

There is a high risk should the primary protection fail to operate and clear the faulted zone, the backup protection will isolate a very large area of customers having a detrimental effect on customer supply reliability at Hunt and Clandeboye substations. This protection arrangement does protect other feeders fed from the common busbar and cannot easily be improved upon without being included within major works which has been the case for new North St Sub (2011, replacing Victoria St) and Grasmere St Sub (2013, 11 kV switchboard and protection upgrade). Regular testing of the remaining legacy protection schemes at Hunt and peer review of protection setting alterations should prevent the level of risk increasing for this sub. To lower the level of risk, upgrading of the electromechanical relays to microprocessor controller equipment at Hunt when equipment reaches end-of life will reduce co-ordination and discrimination problems. Procedures for operating at Clandeboye need regular enforcement, so as to prevent configuring the system to expose risks of backup protection operation.

There is a moderate risk to the dual fibre optic cables associated with the Grasmere, Hunt and North primary protection through improper excavation. If the fibre optic cables are severed the upgraded protection should prevent circuits from tripping. With the two new sub-transmission cables from Timaru GXP to North St, if the load is beyond setting, the protection will clear that feeder without risk to the rest of the network as the remaining cables should not be placed into an overload situation as was the case before the recent upgrades discussed above.

Transformer and switchgear upgrades in 2012 to both Rangitata substation (addition of T2 transformer including 33 kV and 11 kV switchgear) and Pareora Substation (replacement of both banks with larger transformers and indoor 33 kV switchgear) have reduced the risks from high and medium to low. Except that the existing (2008) Pareora Sub 11 kV switchboard risk has only been lowered from high to medium due to both half buses sharing the same room and there being no arc flash containment and ducting to the exterior of the building. The two new Pareora Sub 33 kV switch rooms (one for each half bus) do have arc flash containment and ducting to the exterior and so are rated a risk of low.

The arc flash protection and containment at Grasmere St and North St allows reduced risk while housing both 11 kV busses of these substations in the same room in each sub. Transpower's new Timaru GXP 11 kV Sub has separate rooms for each bus and also full arc flash containment, reflecting the relative importance of this sub. The new Rangitata 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 nor containment.

7.4.3.2 Risk to Incoming Supply

The highest risk category for substations is the reliability of the incoming supply. Typically this is provided via Transpower, however in some cases (not listed in the above table) this is via a single Transpower feeder, resulting in a large outage for the period required to repair. Further studies are required to determine the cost–benefit for duplicate feeders or alternative generation options to reduce the level of risk.

Timaru GXP is at risk as two of three transformers cannot carry peak load.

Bell's Pond substation is a high risk but load can be switched to Studholme sub substation.

7.4.3.3 Risk to Ripple Injection Plant

The ripple injection plants are a critical element in managing controllable load on the 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 demand charges. The ripple injection plants require a critical system spare and connection – commissioning procedure to be developed and implemented.

7.4.3.4 Environmental Risks

Snow and wind typically create high risks in the Mackenzie area of the network. Design standards are employed to ensure adequate strength of materials are used to meet the demands of extreme weather events. Figure 7.2 below, shows snow on network assets on Mt Studholme.

Figure 7.2 Snow on Mt Studholme

The 11 kV switch room at Studholme has been elevated to prevent flood risk. Further pump equipment should be considered as part of contingency planning. Transpower would need to elevate any new works that they may build at Studholme in the future.

Earthquakes pose a significant risk for network interruption and delays in recovery of re-establishing supply. The present likelihood of an earthquake has been defined as possible, as an Alpine fault event is expected now with a probability of 1 in 50 years. The impact of an earthquake event would be Moderate, making this a high risk event for our distribution system. Checks will be required to ensure substations close to the Alpine fault area are seismically restrained. An earthquake from the Alpine Fault would result in some Twizel and Tekapo customers being without supply for several weeks. The high risk at Clandeboye reflects the nature of supply security, while the Mackenzie substations are closest to the Alpine fault and area of the largest expected disruption. The transformer upgrades at Pareora and Rangitata in 2012 have reduced the earthquake risk for these substations from Moderate to Low owing to the addition/replacement of new seismic designed equipment, foundations and buildings.

An extreme tidal wave would be a risk to Studholme, Pareora, and Timaru areas and the Washdyke offices. The present likelihood of a tidal wave has been defined as likely, therefore the risk level is unacceptable. The North St Sub has an additional room and facilities to provide a second base for the control room operations and back-up IT servers in the event of a disaster damaging or destroying the Washdyke offices and depot.

7.4.3.5 Risk to Capacity Headroom

The growth in South Canterbury is consuming the redundant capacity within the Timaru, Temuka, Studholme and Bell's Pond Transpower supply points and may reduce security levels at some times during peak periods to N contingency. This is being discussed further with Transpower to extend capacity and reduce the consequence of supply constraint risk.

7.4.4 Risk Management Strategies

The following strategies are used by us to manage risk:

- Elimination
- Isolation
- Minimisation

This section discusses how we use these strategies to manage risk to our network assets.

Table 7.5 at page 222 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.

Reviewing the level of risk and evaluating the treatments to lower the risk are discussed below for each asset category:

7.4.4.1 Sub-transmission

The 33 kV cables have high risk across the range of our business objectives and have potential to interrupt supply to a large number of customers, it takes from one to two days to effect repairs and they are expensive to repair. The main hazard is if contractors dig them up. Fortunately 33 kV cables are few in number and the risk treatment is for close supervision and control of work occurring from the perspective of safety and reliability. The high risk of cable strike is mitigated by providing contractors with plans of cable locations prior to planned excavations and requiring specific excavation practices near in-service cable(s).

The above risk also applies to the Timaru 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 for the reduction of risk as this will be made feasible as part of 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. The high risk of cable strike is mitigated by providing contractors with plans of cable locations prior to planned excavations and requiring specific excavation practices near in-service cable.

Sub-transmission lines (33 kV) and distribution lines (11 kV) have controllable risks by utilising asset management practices to inspect, maintain and renew assets proactively by identifying deterioration before it becomes critical. Design standards are reviewed based on performance of the assets to maintain a balance between standards of safety and economic supply.

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. There are also some 11 kV cables that pass under 220 kV Transpower line crossings that have no alternative feed and are at risk from lightning despite the surge arrestors fitted.

7.4.4.2 Underground Cables

Further work is required to fully assess the vulnerabilities of buried cable systems and this will be completed in conjunction with the Civil Defence Emergency Management Group (CDEMG) in conjunction with 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.

The high risk is presently mitigated by spares stocks inventories which are generally held for normal repairs rather than natural disasters due to high stock holding costs and items being readily available from suppliers. The higher voltage cables have the highest impact on system reliability and restoration of supply should damage occur.

7.4.4.3 Transformers

Overhead and ground mounted transformers are susceptible to high risk of failure from earthquakes. A stock of spares is carried to mitigate service failure and asset management practices are in place to meet the medium and lower risk exposures.

Voltage regulators, reclosers and ring main units have moderate to low risk levels which are catered for within design standards and equipment spares stock levels.

7.4.4.4 Low Voltage

LV overhead lines have generally low risk levels. The management of risk relies on having sufficient spares to make repairs as well as work practices to ensure quality of supply levels are maintained.

LV underground cables have a low level of risk which is accepted and treated, should the risk eventuate, from the stock holding of spares.

LV distribution boxes are a collection of different box types and configurations. The range of box materials carry different risk profiles, however through programmed condition assessments, work standards and design standards the level of risk remains low to moderate. Mitigation relies on regular surveillance to ensure the integrity of the asset is maintained. There is also a risk of damage from vehicles for some of these boxes.

7.4.4.5 Public Education

We control a number of external risks through public education. By regular media safety messages, the consequences of actions by the public can be communicated and establish an awareness amongst the community of potential hazards as well as a mechanism for contacting us when danger to the public is identified. We have also had meetings with the contractors presently working in the area building the UFB fibre project to assist them in avoiding damage to our underground assets during their excavations and thrust boring operations.

7.4.4.6 Buildings

Building failures have been addressed through seismic reinforcement projects completed previously.

7.4.5 Risk Management Improvements

Plans to improve the management of risks on the electrical network will require the qualitative study to be extended with completion of a formal risk register. This will strengthen the risk management process and drive a regular risk review to check present risk performance and whether any new risks have developed. This will provide a continuous process monitoring and risk review. A database is prepared to record and manage network risks. This is a legislative requirement of both the Health and Safety in Employment Act 1992, and Electricity (safety) Regulations 2010. Therefore dedicated engineering and management resources will be allocated to this task.

There was a strong reliance on the contractor’s stock levels being maintained with us holding a limited stock of special critical spares to mitigate the risk of equipment failure. In 2010/11 a review of the stores system and our critical spares was undertaken to ascertain whether these levels were appropriate. In 2011, following on this review, new indoor and outdoor storage facilities were prepared at Washdyke Depot for our emergency spares and project materials in an appropriate environment and under the stock management of Netcon’s Store. In 2012 these facilities were relocated and the stock levels improved. The contractor will monitor stock levels through its stores inventory system and, with us, will review quantities and re-order levels annually.

Ripple Plant failure is a high risk and further work is required to form an operative contingency plan for this event. Replacement of rotary plant with solid state controllers is an improvement towards risk reduction. Consideration is being given to the option of a mobile or re-locatable spare ripple plant with sufficient injection power capacity and an adjustable filter to enable its use at any of the our ripple control sites, or to holding critical parts that are suitable for use at any of the ripple plants.

A vulnerability analysis is also required to determine quantitatively the cost benefit for either a network or non-network solution for zone substations that are supplied from a single incoming circuit.

Insurance is a valid method of risk treatment and we have a policy cover on major substation equipment.

7.4.5.1 Example of Response to a Low Likelihood, High Consequence Event

On 24th November 2009 at 0455hrs a fire broke out in the Timaru substation causing loss of power to most of the network from the Opihi River boundary down to Pareora and across to Pleasant Point, Cave and Cannington.

The fire damaged the rear of CB15 in the cable box and contaminants spread to CB13, CB14, CB16, as well as sooting the entire switch room. The CB15 cable box was badly damaged as well as the secondary wiring in CB15 and CB16.

This was the first major outage since we re-structured our network operation staff to the central control regime, and the corresponding procedural alteration with respect to response coming directly from Netcon’s fault team.

Two truck mounted generator sets were sourced from Orion and one from Network Waitaki as a contingency measure in case power was not restored overnight to the commercial consumers who have freezer and/or cool store facilities. Fortunately these were not required to be brought into service.

Most outages on our network are caused by events that that are likely to occur during the course of any normal year, such as: wind storms, snow storms, lightning, car hits pole, bird hits line, excavation contractor hits cable, etc. However, the event may have a very low likelihood of occurring as far as a particular item of equipment is concerned.

There are some lines or areas which tend to be more likely to have such events than other areas due to geography, demography, vegetation, line design, overhead verses underground, etc. The recent, and on-going, upgrades to our zone substations, and to Transpower's Timaru 11 kV GXP, has reduced significantly the risk of the event type experienced on the old Transpower GXP 11 kV switchboard (replaced in 2012) described above).

7.4.6 Network Capacity

It is our policy to provide sufficient capacity to meet customer demands, while maintaining its security of supply criteria and operational flexibility, provided pricing returns an adequate return on capacity investment. To this end, the design of any network expansion or development must take into consideration the projected load growth for the area. In addition, all such upgrading or development work must meet with our capital investment criteria, or be funded wholly or in part by the customer.

7.4.7 Operational Security

Capital investment for network security is evaluated based on the:

- estimated cost to customers of energy not supplied, and the
- assessed probability of occurrence and the expected duration of specific events.

Options for reducing the likelihood and/or consequence including network reinforcement, fault reducing strategies (maintenance and replacement) and faster fault response.

7.4.7.1 Environments

Our policy is to act in an environmentally responsible manner and as required under legislation.

The Resource Management Act 1991 is the major legislative driver for us, with the provisions relating to the discharge of contaminants into the environment, the duty to avoid unreasonable noise and the duty to avoid, remedy or mitigate any adverse effect on the environment being of particular relevance. Some of our assets are located in environmentally sensitive areas, which require the company to act in a manner that preserves the environment.

The Resource Management Act 1991 also requires appropriate consents for new work and management systems for environmental and public safety issues in relationship to existing works. We develop practices on the basis of being a reasonable and prudent operator to ensure that environmental and public safety issues have been addressed.

Oil is widely used as an insulating and cooling medium in distribution equipment, and replacement of this oil filled equipment with non-oil filled types is not anticipated in the short or medium term particularly for transformers. Control of this hazard is maintained through oil containment provisions at zone substations and the routine inspection of all oil filled distributed equipment. Oil spill response procedures have been developed and oil spill kits are available at all zone substations, and are carried 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.

7.4.7.2 Electromagnetic Fields

Health effects of power frequency electromagnetic fields have commanded international attention over recent years. 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 customers.

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8 Asset Management Maturity Assessment

8.1 Introduction

This chapter outlines our asset management maturity and identifies improvements that we intend to make to our asset management system (AMS). The AMS is the collective name given to our asset management strategies, processes, systems, and documentation that we use to effectively manage our assets.

8.2 Asset Management Maturity Assessment Tool

The goal of effective asset management is to meet the expected levels of service in the most cost efficient manner through good management of assets now and into the future. We are able to ensure the effective management of our assets by identifying and addressing our weaknesses and building on our strengths. A way of identifying our weaknesses and strengths is through the Asset Management Maturity Assessment Tool (AMMAT).

The Commerce Commission's AMMAT, under the information disclosure requirements[18], 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. On the main we scored ourselves with a maturity level of either:

- 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 did not score ourselves with a maturity or either:

[18] Commerce Commission, Electricity Distribution Information Disclosure Determination 2012, Decision No. NZCC 22, 1 October 2012, clause 2.6.1(5).

- 0—the elements required by the reference standard are not in place, however we are in the process of identifying our understanding of the reference standard.
- 4—we are using processes and approaches that go beyond the requirements of the standard.

Overall we self-assessed our asset management maturity to be 2.23 out of a possible 4. We provide transparency around the reasons for our self-assessed score through the notes under user guidance.

There is no pass or fail as such and we are not required to act on the findings however, we are of the view that a considered effort to increase the scores for some of the questions over the coming years will be in the long-term interests of our consumers. We intend to identify those standards which will provide the greatest benefit for our consumers, and for which we self-assessed ourselves to be less than maturity level 3, and target to improve those to reach at least level 3 over the coming assessment years.

Table 8.2 at page 239, 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, and a comment as to what does the score mean in regard to our asset maturity.

8.3 Continuous improvements to our Asset Management System

Maintaining good asset management practices and making improvements are essential for delivering efficient outcomes to our consumers. We will achieve this through continuous improvement to our asset management strategies, processes, systems, and supporting documentation, including our AMP.

Because of the small size and interconnectedness of our business there has not been pressure to develop formal processes historically. However, because our business is growing, and we are looking for continual enhancement, it is timely that we develop these processes.

The following sections describe those areas that have been identified for enhancement by AMMAT, that will bring most benefit to ourselves and consumers.

8.3.1 Business Process Mapping

During 2014 we will commence stage two of our business process mapping. At stage two 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 (IT) which are integral to our AMS. In August 2011 we engaged Deloitte to carry out a complete review of our IT needs. The report highlighted that our IT systems were outdated and that we were inadequately prepared for disaster recovery. We considered the findings of the Delottie's IT review and determined that we needed a fresh approach to IT for the company as a whole.

In February 2013 we appointed a new IT Manager and created an IT Services group. Over the next five years we plan to completely overhaul our IT systems to provide us with the tools that we need to better provide our services to consumers.

Our IT 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 IT 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 assets 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

While the AMP is a regulatory requirement we also use it as our focal point to guide decision making. Accordingly, the standard must be higher than just compliance. With this is in mind we have dedicated further resources to developing the AMP document over the next three years.

We plan to make the enhancements over three stages, over a three year period. Stage one, includes the restructure our of AMP with incremental changes being made, including to the layout and overall structure of the document; stages two and three, 2015 and 2016 respectively, will include significant development of our AMP.

Table 8.1 over page shows areas identified in our AMP that can be enhanced.

Table 8.1 Areas in the 2014 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.	We are introducing a number of developments this year including a network prioritising process, a formal asset strategy as well as formalising key business processes. These should help to highlight how we align our corporate strategy to plans and activities.
3.10 An overview of asset management strategy and delivery To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify- •how the asset management strategy is consistent with the EDB's other strategies and policies; •how the asset strategy takes into account the life cycle of the assets; •the link between the asset management strategy and the AMP; •processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.	Our asset strategy exists throughout our Asset Management Policy and AMP. However, during development of the next AMP a formal strategy will be created highlighting consistency of the strategy with other key policies, as well as linkages between our strategy and key elements of asset management. This will help with an audit of the AMP and help us to formerly establish key processes.
3.14 An overview of asset management documentation, controls and review processes	Our AMMAT has highlighted the maturity of our asset management related processes. It is our aim to develop formal processes for documentation, control and review. This is underway with the creation of business process mapping.
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	As discussed at section 5.8 we are looking to strengthen our load forecasting. We will do this through the development of an industry liaison team to identify early on industry requirements. We will also strengthen our load forecast models to interpret the impact of possible changes to key variables such as temperature and rainfall. Planning should be further strengthened with the Network Development Plan (NDP) prioritisation process during 2014.

Table 8.2 Extract of Schedule 13: Report on asset maturity

Assessment Category	Question No.	Question	Score Prior year	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	1	All of our policy documents have a stated strategy and objective for that policy and lists all related policies and strategies. For example, section 1.4 of our Asset Management Policy lists the related policies and documents and section 2 provides a comprehensive policy statement linking our corporate strategies.
	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	3	Our Life Cycle Asset Management Planning covers all of our asset types. For example Chapter 6 provides details around maintenance triggers by asset category.
	26	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	2	Our network engineering team meet before the start of the year to set the asset management plan with regard to life cycle activities. We are currently working on appropriate and comprehensive documentation that will clearly demonstrate alignment to asset management objectives and the asset management strategy.
	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?	1	3	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.
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?	1	2	We have developed a Risk Management Policy and are in the process of identifying asset related risk across the asset lifecycle. By our next AMP, in March 2015, we expect to have the appropriate documentation in place so as to demonstrate that the appropriate documented mechanisms are integrated across life cycle phases and that these are being consistently applied.

Assessment Category	Question No.	Question	Score Prior year	Current year	User Guidance
	91	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	2	The overall management of maintenance is the responsibility of the Asset Manager who sets the policies and procedures within the bounds of the AMP and associated policies and strategies. The Asset manager reports progress on the asset maintenance plan to the Network Manager regularly. The Network Manager reports monthly to the board by exception. The reporting between management tends to be informal and is not documented. We are in the process of putting in place formal reporting procedures and reports templates that will better demonstrate our processes to manage and control the implementation of asset management during the lifecycle phase and measure the effectiveness of our 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	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.
Asset Strategy and delivery (Continued)		**Average score**	**1.57**	**2.28**	Our improvement in asset strategy and delivery is the result of having started, and completed, the formalisation and documentation of our policies and strategies.
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?	2	2	We have a service level agreement (SLA) with our preferred contractor Netcon. We meet weekly with Netcon to discuss performance, operational progress and other relevant issues the meetings are minuted. Our current SLA does not make explicit reference to our asset management policies or strategies We are in the process of moving to an Alliance Agreement which will explicitly reference our asset management policies and strategies.

Assessment Category	Question No.	Question	Score Prior year	Current year	User Guidance
	59	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	1	2	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 2 in which we will review and revise our existing BPMs for continuous improvement. We are continuing to develop out IT 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	3	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 our asset management practices.
	88	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	2	We have document control measures in place for all of our asset drawings. And we have established BPMs for the building of new assets. Currently we hold information in multiple systems which make it difficult to demonstrate that lifecycle activities are carried out under specific conditions that are consistent with asset management policies and strategies. Installing a new asset management system will greatly assist us to demonstrate how it is that this requirement.
Documentation, controls, and reviews (Continued)	95	How does the organisation measure the performance and condition of its assets?	2	2	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.

Assessment Category	Question No.	Question	Score Prior year	Current year	User Guidance
	105	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	2	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 intent 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?	2	2	We had our AMP externally reviewed to obtain an option as to the compliance, or otherwise against the Commission's Electricity Distribution Information Disclosure Determination 2012, Decision No. NZCC 22, 1 October 2012. We will, were practicable, implement the recommendations around improvement of our AMP for future reporting periods.
		Average score	**1.71**	**2.14**	Our improvement in documentation, controls, and reviews is the result of having started, and completed, the formal documentation of our processes and the scoping of new systems to support our asset management practices.
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	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.
Systems, integration and information management (Continued)	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	3	During 2013 we restructured the asset management team, and created two new positions Maintenance project manager and Maintenance Engineering Officer. The positions were fully scoped and have complete position descriptions. Position descriptions are held by the Training and Compliance Manager who also holds Safety Management audit reports in the Vault database.

Assessment Category	Question No.	Question	Score Prior year	Current year	User Guidance
	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?	2	2	The importance, relevance, and key information of our AMP are discussed regularly by senior management and our Board at weekly and monthly meetings respectively. Our AMMAT scores and process were externally reviewed to get surety of the result and process taken. We are currently scoping new systems for example, GIS and AMS. Our existing systems are antiquated and do not fully support of asset management system.
	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	1	Data verification, ratification, and cleansing is 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 or 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?	2	2	A function of the newly created IT Manager role will be to develop the IT systems around our AMP requirements based on the process identified by the BPM project. Scoping of IT projects are held by senior management.
Systems, integration and information management (Continued)		**Average score**	**1.80**	**2.00**	Our improvement in systems integration and information management is the result of having restructured our asset management function to better meet our asset management systems. More gains will be made over time in this requirement and we complete the scoping, implementation, and upgrade of our existing IT systems.
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?	2	2	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 customers 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	Score Prior year	Current year	User Guidance
	3	To what extent has an asset management policy been documented, authorised and communicated?	2	3	Our AMP is reviewed and approved by senior management before being reviewed and approved by the board. Groups such as Engineering and the Drawing Office are given hard copies of the AMP. Hard copies are not distributed to all staff however; the AMP is accessible by all staff through the shared drive. The AMP is also discussed as a matter of course at various network meetings and executive management meetings.
	42	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2	3	Progress on the AMP projects features regularly at network team meetings and the Network Manager updates senior management on a weekly basis at the executive management team meeting. Discussions about the meeting of the AMP requirements are kept to those people that are considered to be relevant and who can directly influence outcomes. Variance analysis of actual verses budget is given to the board monthly as part of the board packs.
	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	2	Our AMP is made available to all staff on our internet 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.
Communication and participation (continued)		**Average score**	**2.00**	**2.50**	Our improvement in communication and participation is the result of having made small improvements to our internal communication of our AMP. We intend to draft a stakeholder strategy to better engage with our stakeholders.

Assessment Category	Question No.	Question	Score Prior year	Current year	User Guidance
Structure, capacity, and authority	29	How are designated responsibilities for delivery of asset plan actions documented?	2	2	Accountabilities for Asset Management in our AMP includes discussion of accountability at ownership level, governance, executive, management, operational, works and includes accountability of Netcon our subsidiary. To improve our score we will need to centralise the documentation, currently the documentation is stored in multiple systems or hardcopies which are not easily accessible by those responsible for the delivery of actions.
	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	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.
	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?	3	3	Our asset management team belong to industry groups and attend industry ran seminars. Our newly formed IT Services group keep abreast of improvements in systems. We fully scope all of our use investment analysis tools such as net present value and cost/benefit analysis.
		Average score	**2.33**	**2.33**	No change in our self-assessed scores.
Competency and training	40	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	1	2	The Service Level Agreement held between Netcon and us includes assurance around resourcing and planning. We have not in the past formally documented resource constraints we have tended to deal with events when they have arisen. We recognise the benefits that could be derived from a more formal process and we are looking to put these into action in the future.

Assessment Category	Question No.	Question	Score Prior year	Current year	User Guidance
	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)?	1	1	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?	2	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 asset management plans will be a function of our Alliance Agreement with Netcon.
	50	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	1	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.
Competency and training (Continued)	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	2	We have developed a Risk Management Policy and are in the process of identifying asset related risk across the asset lifecycle. By our next AMP, in March 2015, we expect to have the appropriate documentation in place so as to demonstrate that the appropriate documented mechanisms are integrated across life cycle phases and that these are being consistently applied.
		Average score	**1.20**	**2.20**	Our improvement in competency and training is the result of having made changes to the recording of competencies and the development of our Risk Management Policy.

9 GXP, Substation and Sub–transmission Assets

9.1 Introduction

This chapter contains information on network assets at the GXP, zone substation and sub-transmission level as well as possible developments at the strategic level.

Developments at the strategic level are at the concept stage. Details on planned work for the next 12 months are discussed further in section 5.5 at page 150 of the AMP.

Developments at the concept stage have included possible impacts from major industrial and agricultural developments, utility developments as well as plans and concepts envisioned to resolve major network issues.

This chapter is divided into sections based on the Transpower GXP's. Assets are further described in an order intended to correspond to the geography of the network. This chapter provides a ready reference of the key information above reticulation level.

9.1.1 Ratings

This chapter consists of ratings on network assets. The ratings and rating descriptions are described below:

- Poor = Will need to be replaced in the near future as failure is a possibility
- Good = Sufficient for present needs and security requirements
- Excellent = Unlikely to fail for the foreseeable, and unforeseeable future.

9.1.2 Security Levels

Industry classifications for security level are described below in Table 9.1 and are typically N, or N-1. We also include N-0.5, please refer below for a description of this term.

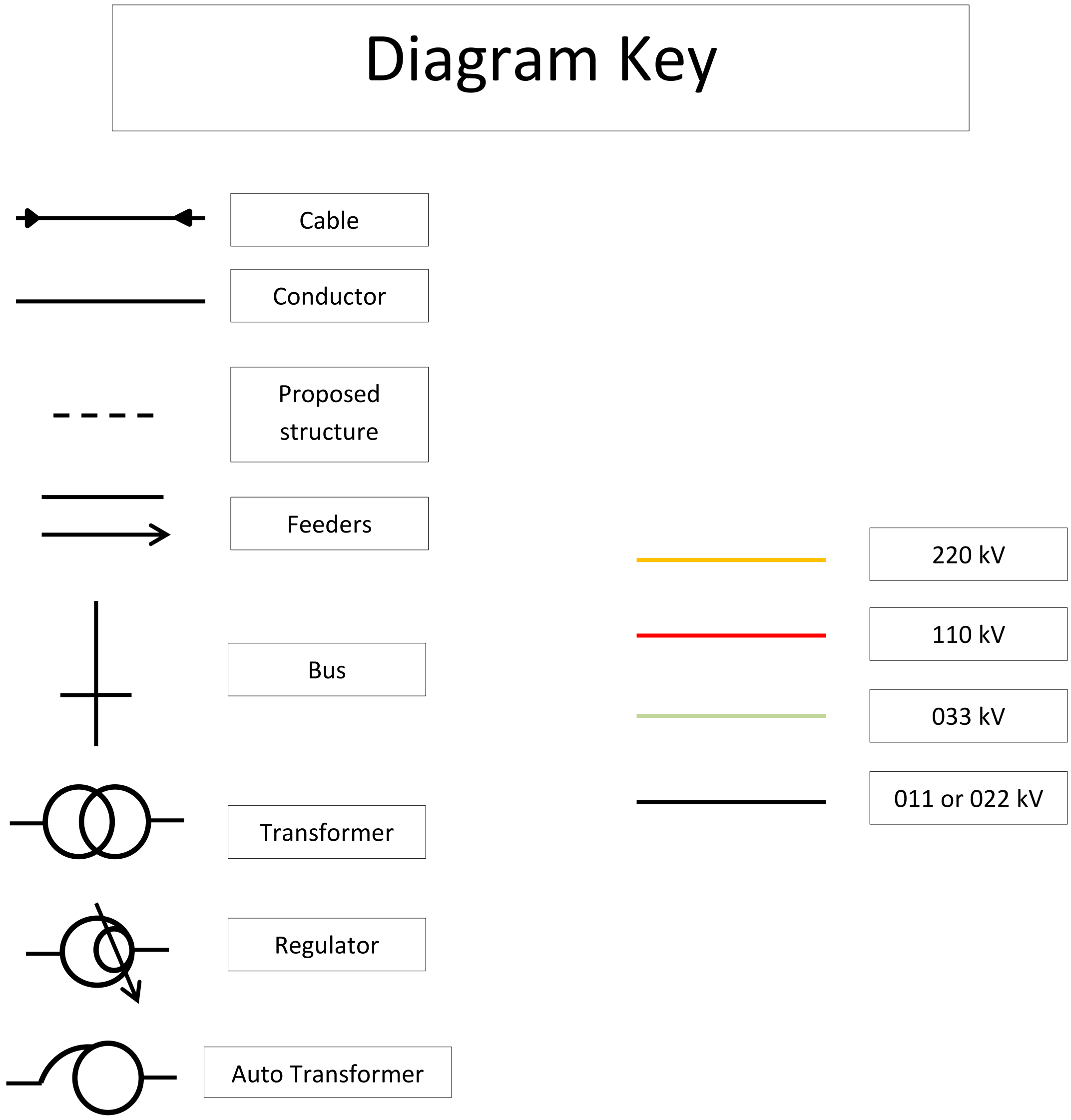
Table 9.1 Security Classifications

Security Level	Description
N	The security level at which any outage will cause load to be tripped, and is often found where there is only one supply circuit or transformer that provides supply.
N-0.5	The security level at which any outage will cause some load to not be supplied after ties are made to other sub stations.
N-1	The security level that ensures supply under a single contingency event.

9.1.3 Diagram Key

Figure 9.1 below lists and describes the symbols used in the network diagrams, used in this chapter.

Figure 9.1 Diagram key



9.1.4 Substation List

Table 9.2 below shows the AEL substations that are associated with each of the seven Transpower GXPs in our network area, as well the substation three letter code used by AEL for reference purposes.

Table 9.2 Substation reference table

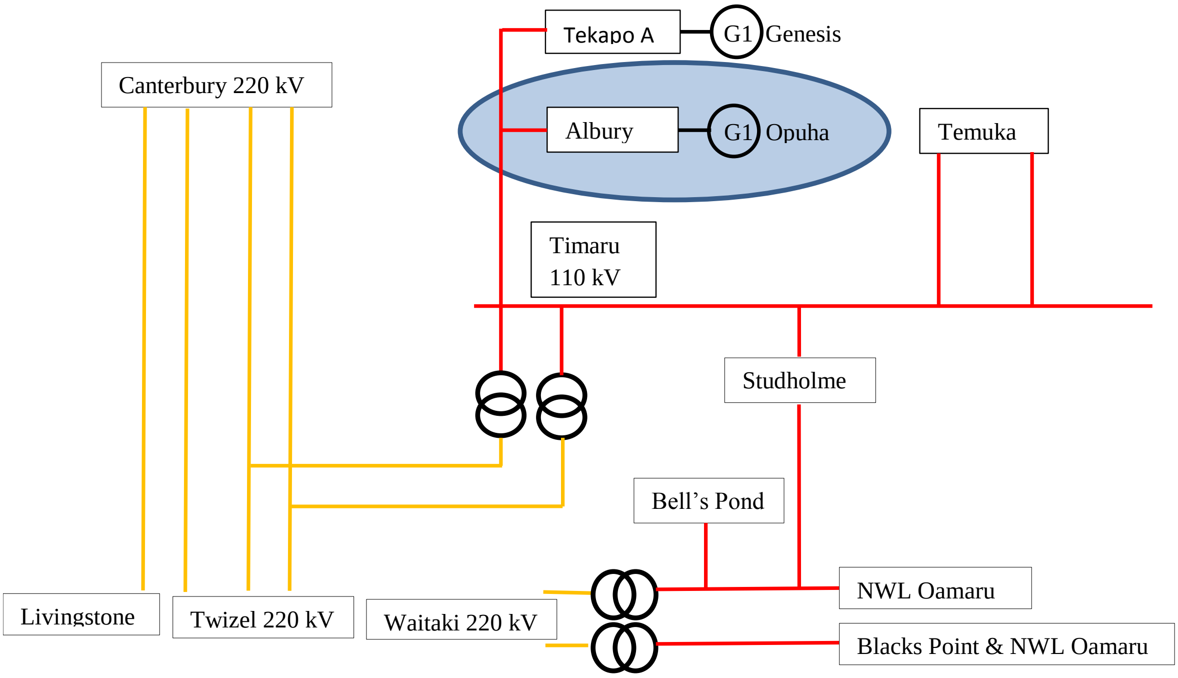
Section:	Transpower GXP:	AEL Zone Substation:	Three Letter Code
9.2	Albury GXP (11 kV)		ABY
9.2.3		Albury (11/33 kV Step-up) (33 kV)	ABY
9.2.3		- Fairlie (33/11 kV)	FLE
9.3	Bell's Pond (110 kV)		BPD
9.3.3		Bell's Pond (110/33/11 kV)	BPD
9.3.3		Cooney's Road (33/11 kV)	CNR
9.4	Studholme GXP (11 kV)		STU
9.4.3		Studholme (switching station) (11 kV)	STU
9.5	Tekapo A GXP (33 kV)		TKA
9.5.3		Tekapo Village (33/11 kV)	TEK
9.5.3		- Balmoral (11/22 kV)	BML
9.5.3		- Haldon Lilybank (11/22 kV)	HLB
9.5.3		- Glentanner (33/11 kV)	GTN
9.5.3		- Unwin Hut (33/11 kV)	UHT
9.6	Temuka GXP (33 kV)		TMK
9.6.3		Temuka (11 kV)	TMK
9.6.3		Clandeboye No.1 (11 kV)	CD1
9.6.3		Clandeboye No.2 (11 kV)	CD2
9.6.3		Geraldine Downs (11 kV)	GLD
9.6.3		Rangitata (11 kV)	RGA
9.7	Timaru GXP (11 kV)		TIM
9.7.3		Grasmere St (switching station - 11 kV)	GRM
9.7.3		Hunt St (switching station - 11 kV)	HNT
9.7.3		North St (switching station - 11 kV)	NST
9.7.3		Timaru (Grant's Hill) (11/33 kV Step-up) (33 kV)	TIM
9.7.3		- Pareora (11 kV)	PAR
9.7.3		- Pleasant Point (11 kV)	PLP
9.8	Twizel GXP (33 kV)		TWZ
9.8.3		Twizel Village (33/11 kV)	TVS

9.2 Albury Grid Exit Point

9.2.1 Introduction

Figure 9.2 below, shows how the Albury GXP (ABY) is configured with our network and Transpower's transmission network. Albury is on the 110 kV line from Timaru 110 kV bus to Tekapo A.

Figure 9.2 Albury GXP configuration



9.2.2 GXP Description

Albury is teed off the TIM-TKA 110 kV line and has a single 110/11 kV transformer connected via one incomer to an 11 kV switchboard, there are three feeder CBs.

The GXP transformer is run as if fixed tap, this does lead to 11 kV voltage fluctuations as the 110 kV supply alters. With a new AVR being installed by Transpower, a request was made that the transformer goes back to on load tap changing, with the ability switched off if there is a reversal of power should Opuha be generating.

Albury's transformer is suitably rated for today's load but is fractionally under rated to pass the embedded generation from Opuha back onto the grid. Trustpower are occasionally asked to back off generation a small amount as there is not 1 MW of load to offset the full generation. As irrigation growth occurs in the area the load capacity headroom on this transformer will be eroded if not consumed.

Within Alpine's network the Totara Valley area is becoming difficult to supply off the Pleasant Point zone substation. An option is to build a new zone substation which would be feed from Albury. This may influence accelerating the replacement of the Albury supply transformer with a larger unit.

Transpower have invested in a mobile sub with 110 kV primary connexion and one of 11 or 22 or 33 kV secondary. It is hoped that in 2014 Albury will be equipped to allow the mobile substation to be connected between the Timaru 110 kV line and AEL's 33 kV feeder or two of the 11 kV feeders. A dead change over will probably be required to insert the substation and significant planning is required to expedite to site.

9.2.2.1 Critical data:

The critical GXP data shown in Table 9.3 below, summarises the key physical attributes of the station, the voltages, the capacity, the security, and the power flow.

Table 9.3 Albury GXP Transpower system data

GXP	GXP Transmission Potential	GXP Point Of Supply Potential	Capacity	N-1 Capacity	AEL Demand Aug '12	Opuha Contribution
Albury	110 kV	11 kV	5/6 MW	0 MVA	4.18 MVA	7 MVA less load

9.2.3 Albury GXP Network Information

Figure 9.3 over page is the Albury GXP area key assets. Transpower delivers 11 kV to AEL's network at Albury zone substation via their circuit breakers 2722, 2732, and 2742. The GXP and zone substation site has the three letter code ABY. Circuit breaker 2722 feeds Albury zone substation to sub-transmit 33 kV to Fairlie zone substation. From Fairlie zone substation a further length of sub-transmission connects Opuha power station to AEL's network. A zone substation is proposed in the Raincliff area if demand necessitates network investment.

9.2.3.1 Albury (ABY) Zone Substation Detail

The zone substation key data shown in Table 9.4 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.4 Albury Zone Substation key data

Transformer	Switchgear	Ripple Plant
7.5 MVA (1997) 33/11 kV OCTC (2008 refurb) Excellent	1x 33 kV Recloser WVE (1994) Fair	Plessey/MetVic 605/510 Hz Rotary

Figure 9.3 Albury–Fairlie area network

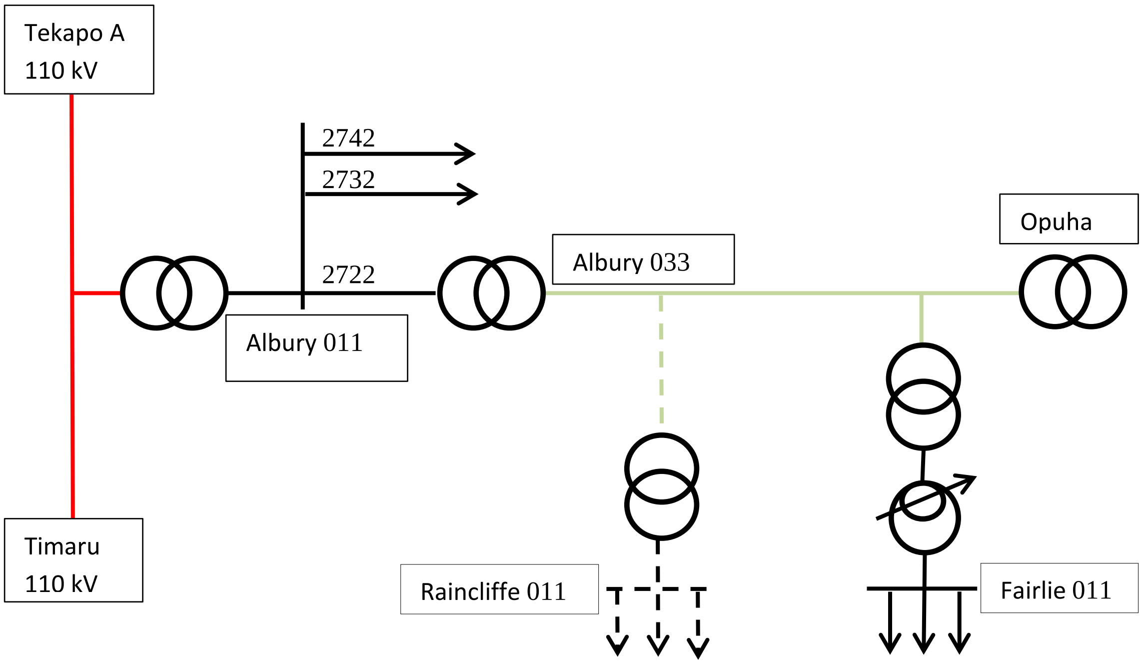


Table 9.5, below lists the existing level of security at the substation and justifies any shortfall.

Table 9.5 Security Level

GXP	Zone Sub/Load Centre	Actual	Target	Shortfall from Target
Albury	Albury Rural	N-0.75	N-0.75	Limited fault back up from adjacent feeders from FLE, PLP and TMK. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table A4.3 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.6 below.

Table 9.6 Estimated demand at Zone Substation level

AEL Zone Sub	2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
Albury 11 kV board	4.20 (summer)	1.26% historic on ABY Irrigation and dairying activity Residential Load Small subdivision development	4.75 (summer)	Transpower asset under their management. Overall load not expected to breach Transpower's capacity unless Totara Valley Sub built.

ABY connects via radio systems, detailed at Table 9.7 below.

Table 9.7 ABY Communications Summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	ABY-MEC MEC-WDK	ABY-BRC BRC-MEC MEC-WDK	None

There is a small amount of traffic on the UHF Analogue that is being decommissioned progressively.

Table 9.8 below, details the SCADA functions at FLE Substation.

Table 9.8 ABY SCADA Summary

Supervision	Control	Automation	Data Acquisition
Current, voltage and CB status at ABY. Security at ABY.	ABY CB control Ripple plant load control	Auto reclosing CB	Load data at ABY

9.2.3.2 *Albury-Fairlie Sub-transmission*

The zone substation key data shown in Table 9.9 below, details the Albury to Fairlie sub-transmission with respect to rating, age, and general condition.

Table 9.9 ABY-FLE Sub-transmission critical data

Line	Make up	Limit at 6% PD (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable (MVA)	Lowest Limit	Notes
ABY-FLE	Dog	7.12	12.6		7.12	1967 build Maintenance priority 6

9.2.3.3 *Fairlie (FLE) Zone Substation Detail*

The zone substation key data shown in Table 9.10 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.10 FLE Zone Substation critical data

Substation	Transformer	Regulator	Switchgear
Fairlie	3 MVA 33/11 kV OCTC (1964)	2 MVA	1 x 33 kV Recloser (1997) 1 x 11 kV Recloser (1989)

Fairlie supplies the local central business district as well the rural surrounds.

It has one incomer recloser and then short distances out from the zone substation various other line reclosures to protect the central business district from rural faults.

Back up for Fairlie used to be made via Opuha if a controlled islanding could be made. Opuha does not black start so alternate supply from Opuha cannot be guaranteed. See also comment below under the Opuha Hydroelectric Power Station re: rough running.

Limited back up of Fairlie can be made from the 11 kV distribution from Albury, this may be sufficient at low load times to supply the central business district alone.

Table 9.11 below lists the existing level of security at the substation and justifies any shortfall.

Table 9.11 FLE Security Level:

GXP	Zone Sub/Load Centre	Actual	Target	Shortfall from Target
Albury	Fairlie	N	N	Limited fault backup. Possibility of some supply from Albury or islanding Fairlie onto Opuha, requires negotiation with generation management, careful islanding, no black start available, generator does not have a lot of inertia constant making speed control a challenge. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table 9.12 below, shows the aggregated effect of substation demand growth for a 10-year horizon incorporating the anticipated step changes shown in Table 9.6 above.

Table 9.12 FLE estimated demand at Zone Substation level

AEL Zone Sub	2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
Fairlie	2.37 (winter)	1.51% historic on ABY Residential load, small subdivision development	3.5 (winter / shoulder)	Regulator upsizing or transformer with OLTC - expect demand to grow from current demand of 2.3 MW to about 3.5 MW over the planning period

FLE connects via three radio systems detailed in Table 9.13 below.

Table 9.13 Communications

VHF	UHF Analogue	UHF Digital
VHF for voice traffic VHF for two bit alarms	None	None

Table 9.14 over page, details the SCADA functions at FLE Sub.

Table 9.14 FLE SCADA Summary

Supervision	Control	Automation	Data Acquisition
2 bit alarm Security at FLE	None	None	None

9.2.3.4 Opuha-Fairlie Transmission

Table 9.15 below, details the Opuha-Fairlie sub-transmission with respect to rating, age, and general condition.

Table 9.15 FLE-OPU Sub-transmission critical data

Line	Make up	Limit at 6% PD (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable (MVA)	Lowest Limit	Notes
FLE-OPU	Jaguar/Cable 1/300	7.65	23.4	21.3	7.65	1997 build Maintenance priority 10

9.2.3.5 Opuha Power Station

Opuha power station (OPU) is an asset owned by local irrigators and operated by Trustpower. The primary purpose of the dam is to break the kinetic energy of outflows from the dam into the Opuha River. The generation rough runs at part load so its use as back up to Fairlie is limited.

9.2.4 Development of Albury GXP and Substations

Albury GXP calculated load growth is 1.26%. This is mainly due to growth in the farming- and tourism sectors. A new source of irrigation would be required to see step change growth.

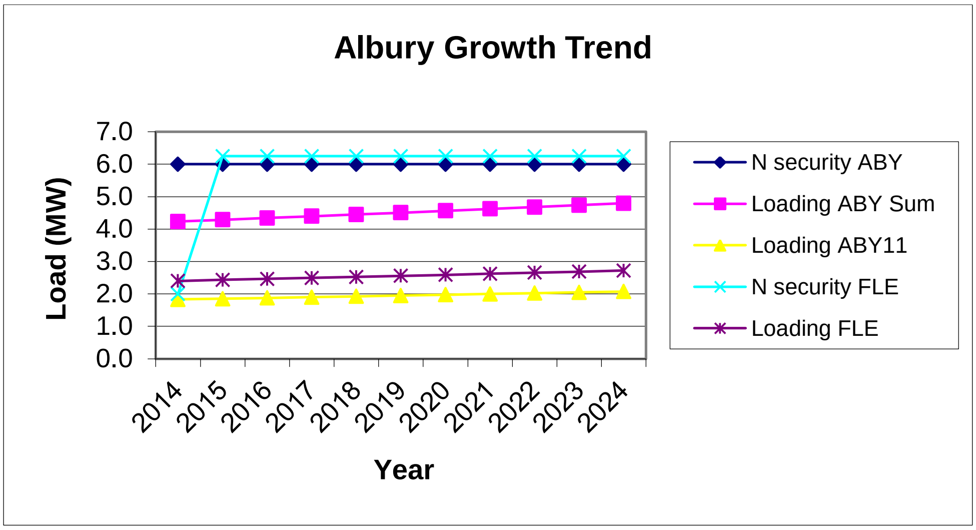
Table 9.16 below, shows the growth trend to the year 2024.

Table 9.16 Substation Load Growth

GXP Substation (Season Peak)	Growth Trend (Total MW MD)										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Albury (Summer)	4.2	4.3	4.3	4.4	4.5	4.5	4.6	4.6	4.7	4.7	4.8

Figure 9.4 over page plots the security levels and the maximum demand at Albury and Fairlie.

Figure 9.4 Albury Growth Trend and Supply Security



9.2.4.1 Substation Growth Trend and Supply Security

The areas load continues to grow in response to the farming and irrigation activities in the area. If Transpower's Timaru T4 becomes available it may be worth considering installing it at Albury.

The Fairlie regulator is undersized at 2 MVA to take the peak load of the day. Consideration is being given to moving one of the 5/6.25 MVA OLTC transformers recently retired from Pareora to Fairlie.

Figure 9.4 does not include the Totara Valley substation development.

9.2.4.2 Rate and Nature of GXP Growth and Provisions made

Table 9.17 below summarises the characteristic of the growth and summarises the plans to meet the energy requirements of the growth.

Table 9.17 Growth and Response

GXP	Rate and nature of growth	Provisions for growth
Albury	Med – Rural	GXP investment if Totara Valley connected

9.2.4.3 Specific Developments

Totara Valley Development – Options of Raincliffe and Cave

Load flows indicate that the 33 kV Pleasant Point-Timaru sub-transmission is capable of delivering 8.27 MVA load with a 6% potential drop. The line should only be operated to 9 MW. At present the Pleasant Point zone substation feeds into Totara Valley and up to Raincliff while Albury feeds down to Cave.

The majority of the load in this mid ground is presently on the Pleasant Point substation. Two enquiries for pumping loads totalling 2 MVA (which have stagnated) have been received for the Totara Valley area. The transformer at Pleasant Point has an upper rating of 6.25 MVA with a present peak load of about 4 MVA noted. These new loads alone will load Pleasant Point's transformer to capacity if established, and in addition cause serious potential drop on the lengthy 11 kV feeder to the Totara Valley area, drop that probably cannot be remedied by capacitors or voltage regulators.

The option to install a second transformer at Pleasant Point to supply the load is not viable. The regulator is installed at Tengawai to support the Totara Valley area growing load is already operating on upper taps.

Another option is to partially off load Pleasant Point with the possible establishment of a zone substation at Totara Valley fed off the 33 kV Albury-Fairlie sub-transmission. This will also solve voltage regulation concerns on the 11 kV feeders.

One consideration in increasing the load on Albury would be that the Transpower transformer is rated presently at 6 MVA. Presently there is about 4.2 MVA of load applied when Opuha is off, there is limited spare capacity available. Transpower will be looking to upgrade the transformer at Albury in 2017/18, a size increase may be needed.

A more detailed study is required to examine the above and other options not explored. A further AEL project is proposed that will replace the existing 33 kV neutral earthing transformer which has internal partial discharge concerns, and replace the existing earth fault protection relays which are at end of life.

Ripple Load Control

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, both units located outside the ripple plant building.

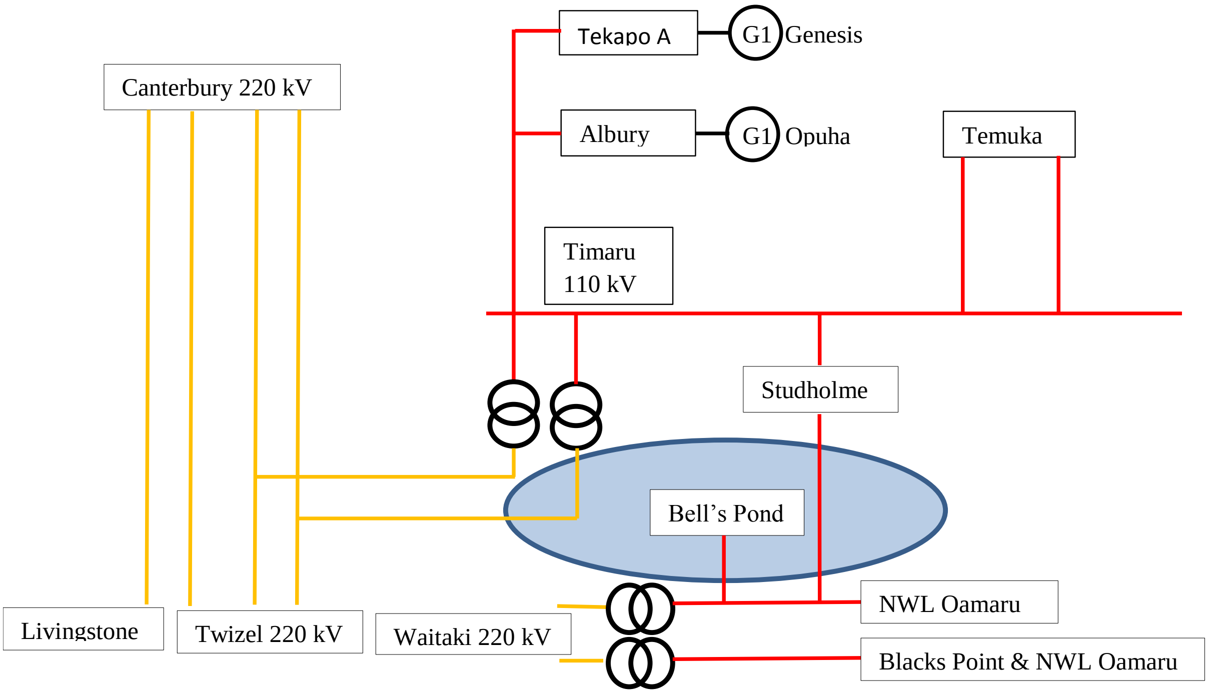
The ripple injection plant is presently a rotating plant. This will be replaced by a static convertor in 2014/15.

9.3 Bell's Pond Grid Exit Point

9.3.1 Introduction

Figure 9.5 below shows how the Bell's Pond GXP (BPD) is configured with our network and Transpower's transmission network. Bell's Pond is on 110 kV circuit from Waitaki to Glenavy.

Figure 9.5 GXP configuration



9.3.2 GXP Description

Bell's Pond GXP is a single tee off the STU-OAM-WTK 2 110 kV circuit. The GXP is essentially a 110 kV metering point which was made available to AEL so that a 110/33/11 kV zone substation could be connected.

Bell's Pond GXP was established and commissioned in August 2010 which off loaded just over 6 MW of load from Studholme. Transpower recently denied the opportunity to connect a second transformer at Bell's Pond to the second 110 kV circuit that would have removed the present need for Studholme to back up the Bell's Pond load.

9.3.2.1 Critical data

The critical GXP data shown in Table 9.18 over page, summarises the key physical attributes of the station, the voltages, the capacity, the security, and the power flow.

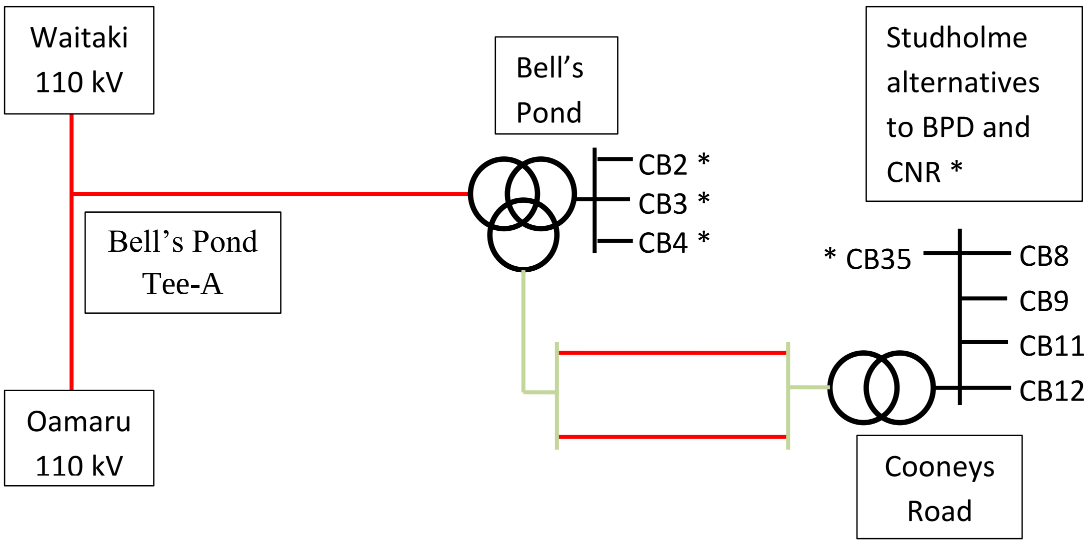
Table 9.18 Bell's Pond Sub key data

GXP	GXP Transmission Potential	GXP Point Of Supply Potential	Capacity	N-1 Capacity	AEL Demand Feb '13
Bell's Pond	110 kV	110 kV	20 MVA	5 MVA	7.0 MW

9.3.3 Bell's Pond GXP Network information

Figure 9.6 below shows the BPD GXP area key assets. Transpower delivers 110 kV to AEL's network at Bell's Pond zone substation. The Bell's Pond GXP and zone substation site has the three letter code BPD. From BPD 110/33/11 kV transformer's 33 kV winding a sub-transmission line has been constructed to a new zone substation at Cooneys Road (CNR), rated at 110 kV, this will be livened in April 2014. Cooneys Road substation will supply Oceania Dairy Ltd

Figure 9.6 Bell's Pond GXP area network



9.3.3.1 *Bell's Pond (BPD) Zone Substation detail*

The zone substation key data shown in Table 9.19 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.19 Bell's Pond Zone Substation key data

Transformer	Switchgear	Ripple Plant
15/20 MVA 110/33/11 kV (2010) Excellent	1 x 110 kV GL312 Areva (2010) Excellent 5 x 11 kV RPS (2010) Excellent	Abbey Systems RTU Landis and Gyr Ripple Plant (2010 cell/2011 processor) Excellent

Table 9.20 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.20 Security Level

GXP	Zone Sub/Load Centre	Actual	Target	Shortfall from Target
Bell's Pond	Bell's Pond Rural	N-0.75	N-0.75	Back up supply from STU. STU can take majority of load if both STU transformers are in service. Some irrigation would have to be disconnected. Encourage customers to be self-sufficient for their essentials, as for CD emergencies. Second transformer being considered, to gain security this would have to connect to OAM-WTK 1 line.

The estimated demand listed in Table 9.21 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.30 at page 265.

Table 9.21 Estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
14.4 (summer)	5.89% per year expected residential load Dairy and Irrigation development	30.6 (summer)	New substation to offload Studholme and provide more security and capacity. Work needed to carry load which depends on mooted projects progressing.

Table 9.22 below, shows the communications system to AEL headquarters.

Table 9.22 BPD Communications Summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	None	BPD-MEC MEC-CHC CHC-NST or WDK	None

Chorus provide telephone, fax services via Cu connexion. Transpower use Chorus for certain data retrieval.

Table 9.23 below, shows BPD SCADA, BPD has an SEL 2032 for most IED connexions and an Abbey RTU to control the ripple plant.

Table 9.23 BPD SCADA Summary

Supervision	Control	Automation	Data Acquisition
Current, voltage, power and CB status	BDP area CB, Transformer and Ripple plant Control	CB and transformer control	Load data and power quality at BPD

at BPD.			

9.3.3.2 Bell's Pond-Cooneys Road Sub-transmission

The zone substation key data shown in Table 9.24 below, details the Bell's Pond-Cooneys Road sub-transmission with respect to rating, age, and general condition.

Table 9.24 BDP-CNR Sub-transmission critical data

Line	Make up	Limit at 6% PD (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable (MVA)	Lowest Limit	Notes
BPD-CNR	110 kV double cct bonded Jaguar					2013 build Maintenance Priority 10

9.3.3.3 Cooneys Road Zone Substation Detail

The zone substation key data shown in Table 9.25 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.25 Cooneys Road Zone Substation key data

Transformer	Switchgear
9/15 MVA 33/11 kV (2014) Excellent	1 x 110 kV GL312 CB (SF_6) (2013) Excellent 8 x 11 kV RPS (2014) Excellent

Table 9.26 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.26 Security Level

GXP	Zone Sub/Load Centre	Actual	Target	Shortfall from Target
Bell's Pond	Dairy Processing	N-0.1	N-0.1	No full security to site as agreed with customer. Light back up supply from Studholme. Later investment when process proven to increase security.

The estimated demand listed in Table 9.27 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes.

Table 9.27 Estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth

0 (summer/winter)	Dairy Processing	20 (summer/winter)	Assumption is to prepare site for two driers initially with extensions later. AEL have included for 4 by 5 MW driers in planning.

9.3.3.4 Communications Systems

CNR connections are shown in Table 9.28 below.

Table 9.28 CNR Communications Summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
Voice	None	CNR-MEC MEC-CHC CHC-NST or WDK	None

9.3.3.5 SCADA Systems

CNR has dual SEL 3035 for most IED connexions, SCADA detailed in Table 9.29 below.

Table 9.29 CNR SCADA Summary

Supervision	Control	Automation	Data Acquisition
Current, voltage, power and CB status at CNR. Security monitor.	CNR area CB and transformer control	CB and transformer control	Load data and power quality at CNR

9.3.4 Development of GXP and Substations

Figure 9.6 above, shows Bell's Pond estimated load growth. A second 20 MVA transformer and possibly an increase of capacity in the existing T2 will be required for the site to increase the N transformer security to 40 MVA. AEL are working with Transpower to gain a supply for the second transformer.

The Oceania Diary factory is presently under construction with the commissioning of stage one expected in the second quarter of 2014, load in the order of 5 MVA. A temporary supply off the 33 kV winding at Bell's Pond has been made to supply the initial two stages of the dairy factory (10 MVA). As the factory grows beyond 10 MVA a permanent 110 kV supply will be required.

In early 2012 and in 2013, enquiries were revisited about the Waihoa Downs/Elephant Hills irrigation with load of 7 to 10 MW. The load for the Waihoa Downs/Elephant Hills irrigation load would be split over the 11 kV and 33 kV windings of the transformer with the bulk being on the 33 kV. Permanent 33 kV assets at Bell's Pond would have to be developed. Much of the on farm development that would flow on from this irrigation is too distant for 11 kV distribution so a 33 kV substation in the Waihoa Downs area and 33 kV sub transmission to it would be required. The farmers did not show enough interest at this time, the project seems to be on hold, AEL have tentatively moved it to 2016.

In the event of a failure of the single Bell's Pond transformer Studholme load transfer is the perceived security for some of the load. The milking shed load would be able to be transferred to Studholme. ODL load will be lost. Some irrigation load could be cycled between milking.

Meridian's proposed North Bank Tunnel hydro station project is understood to be cancelled, it is removed from AEL's planning.

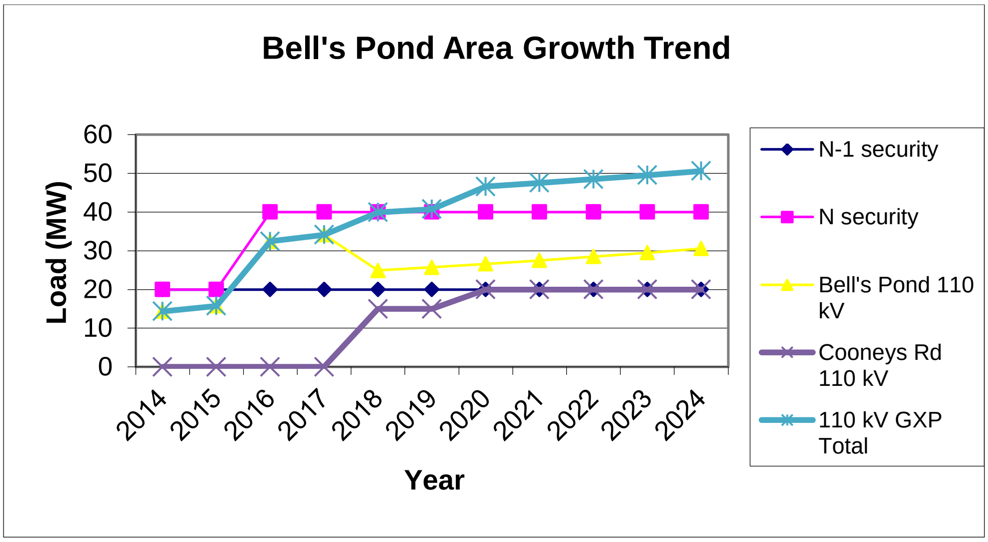
Table 9.30 below, shows the growth trend to the year 2024

Table 9.30 Substation Load Growth

GXP Substation (Season Peak)	Growth Trend (Total MW MD)										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Bell's Pond (Summer)	14.4	15.8	32.4	34.1	24.9	25.7	26.6	27.5	28.5	29.5	30.6

Figure 9.7 over page, plots the maximum demand predictions in the Bell's Pond GXP area.

Figure 9.7 Bell's Pond Growth trend



9.3.4.1 *Substation Growth Trend and Supply Security*

The areas load continues to grow in response to the farming and irrigation activities in the area. ODL will initially add 5 MW to BPD load, rising in the future to approximately 20 MW; this will require the BPD-CNR 33 kV circuit to be re-connected to 110 kV.

9.3.4.2 *Rate and Nature of GXP Growth and Provisions made*

Table 9.31 below summarises the characteristic of the growth and summarises the plans to meet the energy requirements of the growth.

Table 9.31 Growth and Response

GXP	Rate and nature of growth	Provisions for growth
Bell's Pond	High—Rural, Industrial Dairy factory	New investment to secure the energy needed off the grid.

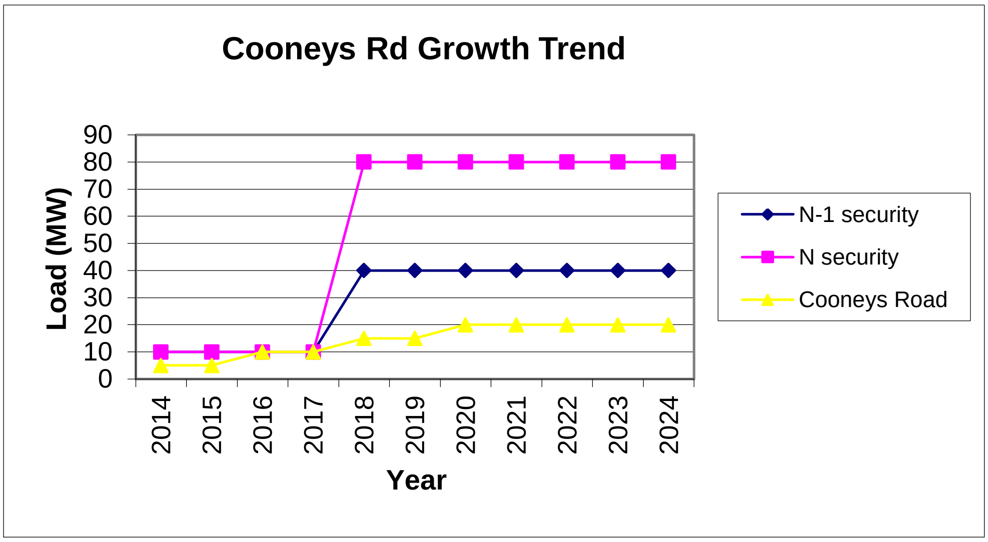
9.3.4.3 Specific Developments

Cooneys Road Development—Options for capacity increase for Oceania Dairy's Limited's Milk Solids Plant

Cooneys Road zone substation is in the process of being fitted with 33/11 kV equipment ready for the first stage of ODL's dairy factory. The sub-transmission line from BPD to CNR is rated at 110 kV and with investment in 110/11 kV transformers at CNR the dairy factory will not be capacity constrained. Security however is reliant on 11 kV feeders from Studholme substation with a capacity of approximately 2 MW. To create any significant security of supply would require sub-transmission investment from Studholme.

Figure 9.8 below, plots the maximum demand predictions for Cooneys Rd zone substation.

Figure 9.8 Cooneys Rd Growth Trend



9.3.4.4 Issues Arising from Estimated Demand

In December 2013 Transpower realised that for a tripping of the Oamaru-Waitaki 110 kV circuit 1, that circuit 2 with; Bell's Pond, Oamaru and Studholme connected could become overloaded at peak periods. Transpower's best option for overcoming the overload was to ask AEL to shed Bell's Pond. This will become increasingly difficult as Bell's Pond becomes more loaded with the first two stages of Oceania Dairy.

AEL is still in the situation that if Bell's Pond GXP or the 110 kV circuit to it fails, essential loads on the Bell's Pond GXP need to be supplied off Studholme. Until Bell's Pond can be made secure by a second connexion then the ability to supply the load within Studholme's N-1 capacity is becoming reduced.

Recently Transpower denied AEL a connexion to the number 1 circuit so Bell's Pond cannot be made secure in the short term.

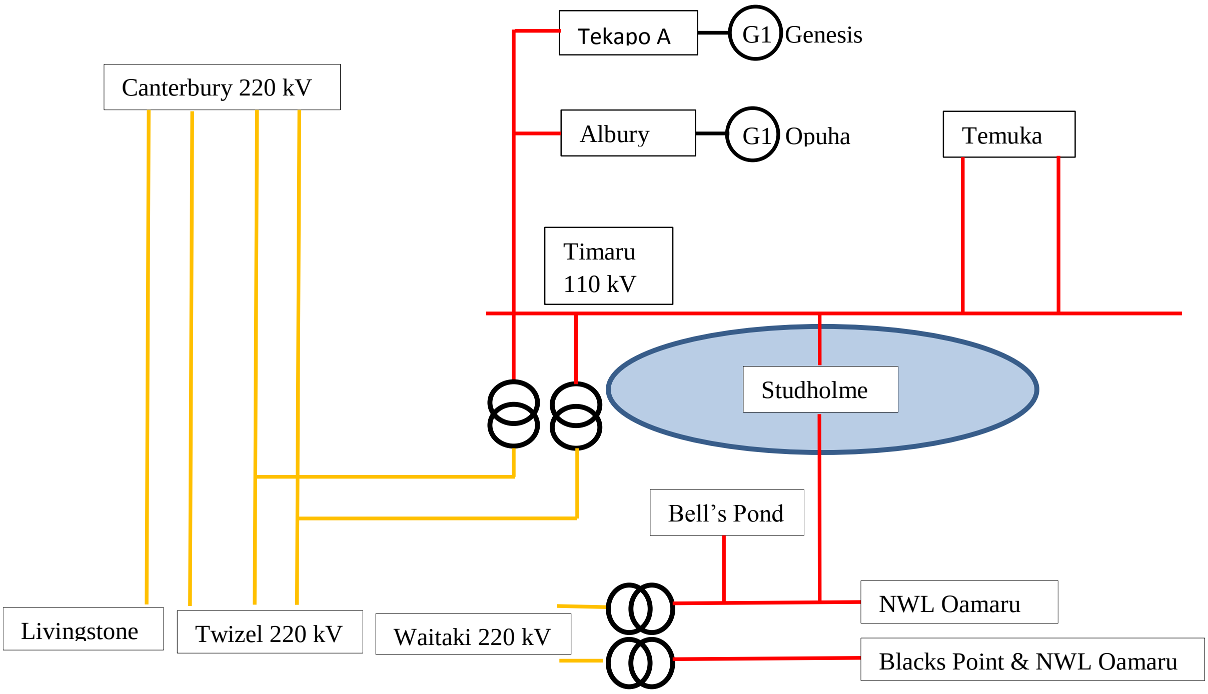
AEL have been working with NWL and Transpower on an alternate supply into the lower Waitaki area, Transpower have offered a connexion to the Livingstone-Islington 220 kV circuit with a limit of 50 to 70 MVA. Loads AEL envisage are total more than this. If AEL are to share the new GXP with NWL then the situation becomes impracticable.

9.4 Studholme Grid Exit Point

9.4.1 Introduction

Figure 9.9 below, shows how Studholme GXP (STU) is configured with our network and Transpower's transmission network. Studholme is supplied by 110 kV circuit from Glenavy on the 110 kV Circuit 2 to Waitaki.

Figure 9.9 GXP configuration



9.4.2 GXP Description

Studholme GXP provides two 11 kV incoming supplies to AEL's 11 kV switchboard which is co-sited at the GXP. Six 11 kV feeders provide supply to the Waimate township, Fonterra's Studholme dairy factory, and the surrounding rural areas. The substation demand is summer peaking from strong growth from the dairy factory, arable/dairy farming and irrigation demand.

Partial off load of Studholme occurred at the end of August 2010 with the full commissioning of Bell's Pond substation. The remaining load is still greater than the N-1 security offered from a single transformer. At times Bell's Pond will have to be removed from service when the sole 110 kV line that supplies it is released so Studholme has to have the firm capacity to uptake Bell's Pond load, or at least as much load as the feeders towards Bell's Pond can support.

From April 2014 Studholme will be called on from time to time to provide some energy to Oceania Dairies Ltd (ODL) on Cooneys Rd to assist their environmental requirements while the main supply from Bell's Pond is released.

9.4.2.1 Critical data:

The critical GXP data shown in Table 9.32 below, summarises the key physical attributes of the station, the voltages, the capacity, the security, and the power flow.

Table 9.32 Studholme zone substation key data

GXP	GXP Transmission Potential	GXP Point Of Supply Potential	Capacity	N-1 Capacity	AEL Demand Feb '13
Studholme	110 kV	11 kV	22 MVA	11 MVA	11 MW

Table 9.33 below, shows the capacity constraints on AELs network in the Studholme GXP area network.

Table 9.33 AEL Network constraints

Constraint	Description	Intended remedy
Lack of capacity for Waimate area	Lack of capacity for Studholme, Bell's Pond GXP's	Work with Transpower on their Lower Waitaki project to ensure capacity is made available.

9.4.3 Studholme GXP Network information

Figure 9.10 shows the Studholme GXP area key assets. Studholme GXP delivers 11 kV to AEL's indoor switch room, supplying at 11 kV the nearby Fonterra Studholme dairy factory, Waimate township, and the surrounding rural area. The Studholme GXP and zone substation site has the three letter code STU. From Studholme two feeders supply Fonterra's dairy factory.

9.4.3.1 Studholme (STU) Zone Substation detail

The zone substation key data shown in Table 9.34 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.34 Studholme zone substation key data

Switchgear	Ripple Plant
9x 11 kV VCB (2005) Excellent	Zellweger 317 Hz

Figure 9.10 Studholme GXP area network

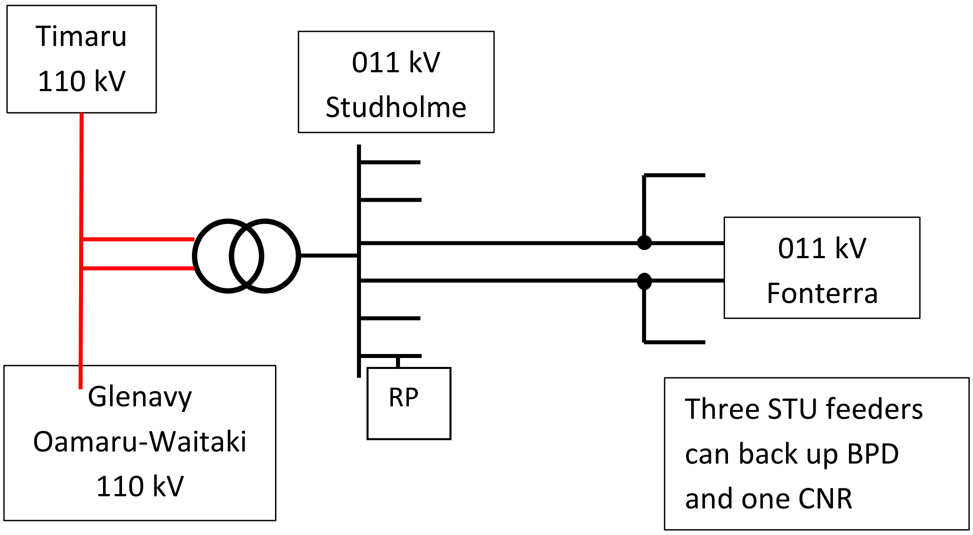


Table 9.35 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.35 Security level

GXP	Zone Sub/Load Centre	Actual	Target	Shortfall from Target
Studholme	Waimate Residential	N-1	N-1	Limited 11 kV rings from STU. Limited fault backup from BPD.
	Waimate Rural	N-0.5	N-0.5	Limited fault backup from BPD and PAR. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.
	Fonterra 11 kV	N	N-1	Load over 3 MVA requires customer investment for dedicated feeders/cables. Present load restricting load growth and increasing voltage problems towards end of feeders. Limited 11 kV rings.

The estimated demand listed in Table 9.36 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.39 on page 271.

Table 9.36 Estimated demand at zone substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
11.1 (summer)	3.19% per year expected as TMK Residential load	29.6 (summer)	Transformer upsizing required pending load split for Hunter Downs

	Dairy and irrigation development		between STU and STA. 11 kV switchboard upsizing required after 24 MVA.

Communications are detailed in Table 9.37 below.

Table 9.37 STU Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	Analogue for all 11 kV station SCADA and load control functions	None	None

Studholme SCADA systems are detailed in Table 9.38 below. Abbey RTU connects to IEDs. Abbey RTU controls ripple plant.

Table 9.38 STU SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, voltage and CB status at STU. Security at STU	STU area CB and ripple plant Control	Auto reclosing CB at STU	Load data and power quality at STU

9.4.4 Development of GXP and Substations

Table 9.39 below, shows the growth trend to the year 2024. The proposed GXP at St. Andrews will allow significant load as a result of the Hunter Downs Irrigation to picked up by AEL; this will however require significant infrastructure investment.

Table 9.39 Substation load growth

GXP Substation (Season Peak)	Growth Trend (Total MW MD) Year 20xx										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
St. Andrews	0.0	0.0	0.0	0.0	0.0	26.0	27.2	28.3	29.3	30.1	30.9
Studholme (Summer)	11.8	12.1	12.4	12.8	22.1	23.6	25.0	26.3	27.5	28.5	29.6

Table 9.39 above, shows the Studholme and St. Andrews load growth. After Bell's Pond commissioning, Studholme load was reduced and new investment differed. The data allows for a new GXP at St. Andrews to take some of the existing Studholme area load and the Hunter Downs Irrigation. New transformers for Studholme are taken as 40 MW as these are practically sized to suit standard 11 kV switchgear (ie 48 MVA practical limit on CBs).

The date of introduction is load dependant and needs to be scheduled with other Transpower work. Figure 9.11 below, plots the Studholme load growth after Bell's Pond commissioning and allowing for a new GXP at St. Andrews to take some of the existing Waimate area load.

Figure 9.11 Studholme growth trend

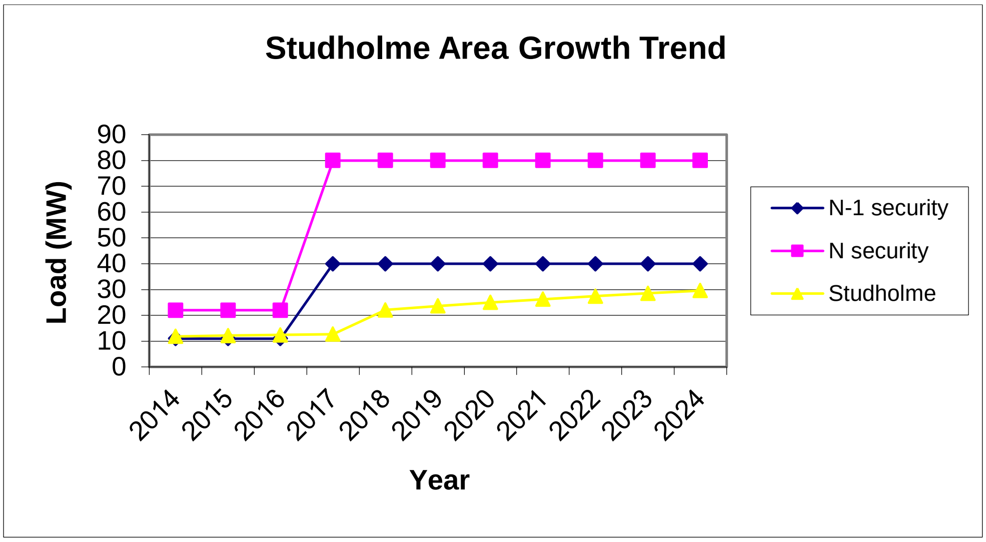
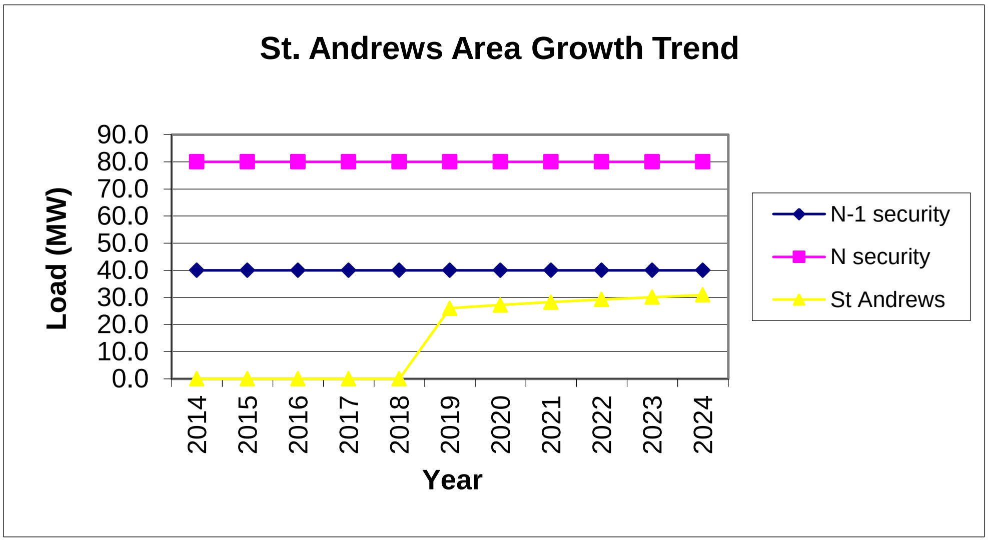


Figure 9.12 below, plots the expected growth in the St. Andrews area, anticipating network development to result in increased supply from 2018.

Figure 9.12 St Andrews area growth trend



9.4.4.1 Substation Growth Trend and Supply Security

The Waimate area consists of the areas supplied by Bell's Pond and Studholme. When the larger irrigation projects progress it is foreseen that a new GXP will be required at St. Andrews and work done to gain a new GXP to feed Bell's Pond from an alternate source than the present 110 kV Waitaki circuits, these have no spare capacity. Alpine are discussion options with NWL and Transpower. Waimate area growth trend is found at Figure 9.13 over page.

With Fonterra's Studholme plant being on two overhead feeders, some of the traditional Waimate load was shifted to Pareora (which is in turn supplied off Timaru) to overcome sagging potentials in the St. Andrews area. Both of the feeders toward St. Andrews are now at the end of capacity with voltage regulators and capacitors applied.

Studholme’s GXP presently has two 10 MVA (allowed to run to 11 MVA each) transformers that are bolted together giving 22 MVA of N capacity. If one of the transformers failed (which has happened in the past), Transpower would “unbolt” the transformers while the power is off and then liven the healthy transformer and restrict demand to 11 MVA of load. Present loads indicate that if this occurred some irrigation would have to be turned off until the faulty transformer has been repaired.

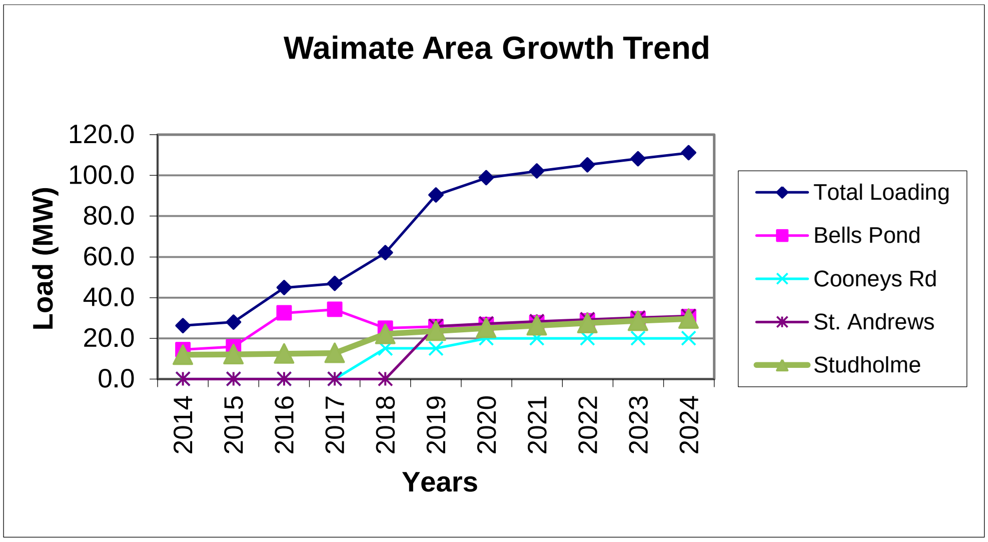
Bell’s Pond GXP was established and commissioned in August 2010 which off loaded just over 6 MW of load from Studholme. Studholme still just breaches the 12 MW N-1 security rating and with the expected 3.19% load growth in the area by 2014, the security risk at Studholme is still not resolved. Transpower recently denied the opportunity to connect a second transformer at Bell’s Pond to the second 110 kV source that would have removed the present need for Studholme to back up the Bell’s Pond load.

The rating of the Studholme 11 kV board is 24 MVA, if Bell’s Pond was no longer reliant on Studholme the switchboard’s rating would be sufficient well into this planning period and should only be contemplated for an upgrade when larger transformers would be required. A new GXP at St. Andrews would further unload Studholme and ensure that the present switch board with bigger transformers will suffice well into this planning period.

St Andrews would pick up load on the feeder between Studholme and Pareora relieving another constraint.

New transformers for Studholme are taken as 40 MW as these are practically sized to suit standard 11 kV RPS 2500 amp switchgear (ie 48 MVA practical limit on CBs). The introduction timing is load dependant and needs to be scheduled with other Transpower work.

Figure 9.13 Waimate area growth trend



9.4.4.2 Rate and Nature of GXP Growth and Provisions made

Table 9.40 below, summarises the characteristic of the growth and summarises the plans to meet the energy requirements of the growth.

Table 9.40 Growth and response

GXP	Rate and nature of growth	Provisions for growth
Studholme	High – dairy and irrigation Med – Dairy processing	New GXP investment

9.4.4.3 Specific Developments

St Andrew's GXP Development

Makikihi/St. Andrews is a similar initiative to Bell's Pond. AEL's view of the project would be to build an in/out deviation off the Studholme-Timaru 110 kV transmission circuit or Meridian's view would be an in/out deviation off the Livingston/Islington 220 kV transmission circuit.

9.4.4.4 Issues Arising from Estimated Demand

After 2009 discussions with Transpower regarding the strengthening of Studholme capacity declined, AEL take the full N capacity of the station. AEL continues to see demand rise with farming activity. Any extensions at Fonterra's Studholme plant would spur a major rebuilding programme at Studholme GXP, Fonterra will construct faster than Transpower.

AEL discussed with Transpower to have Studholme's capacity increased via two 40 MVA 110/11 kV transformers and a new 11 kV switchboard. Alpine's switchboard is rated 23.8 MVA which will be insufficient to match the new transformers.

AEL have a temporary arrangement with Transpower for a 110 kV bus tie through for the milk flush, this gives Fonterra security. Transpower hint at removing the tie, if this occurs Fonterra will experience less security of supply and significant economic losses.

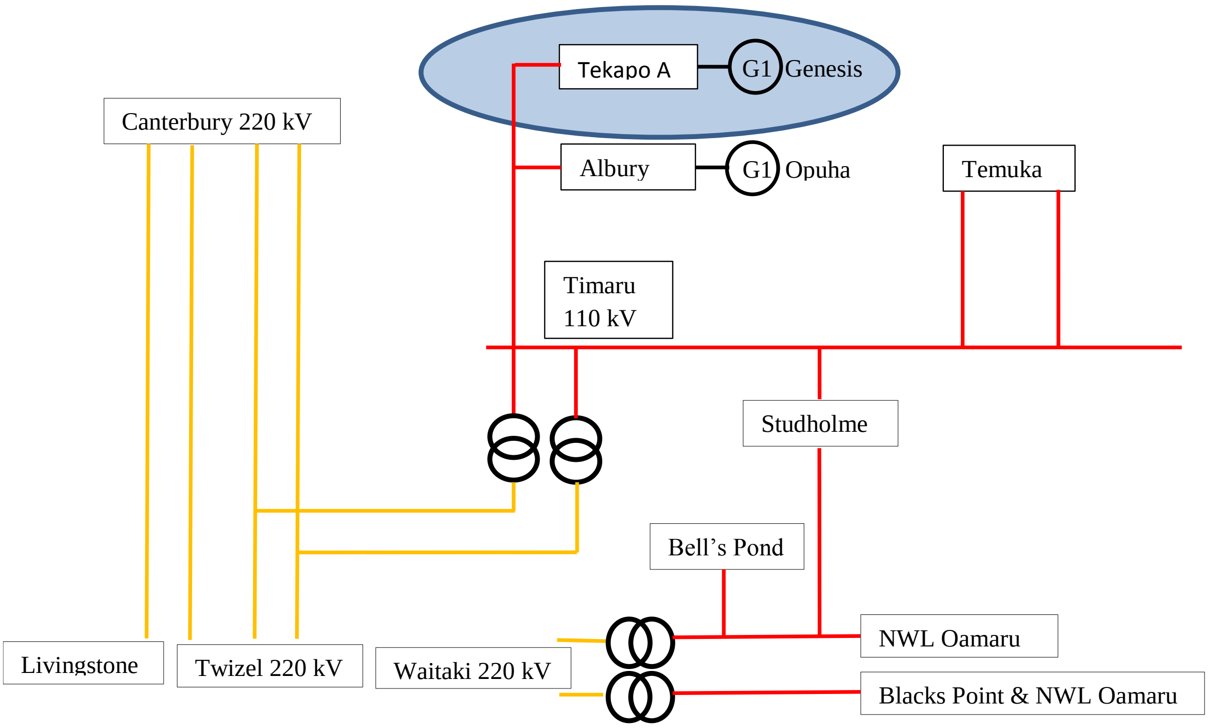
AEL approached Transpower for a second circuit to feed Studholme from Glenavy in the 2007 era. The growth between NWL and AEL in the meantime has probably thwarted this initiative similarly with Bell's Pond not being able to be made secure.

9.5 Tekapo Grid Exit Point

9.5.1 Introduction

Figure 9.14 below, shows how Tekapo A GXP (TKA) is configured with our network and Transpower's transmission network. Tekapo A GXP, is supplied by 110 kV circuit from Timaru 110 kV bus via Albury.

Figure 9.14 GXP configuration



9.5.2 GXP Description

Tekapo A is connected to the grid via a 110/11 kV transformer. Genesis (previously Meridian owned) can make their generator available if the grid is unavailable. Generally when the Albury-Tekapo A or Albury-Timaru 110 kV circuits are released, Genesis can run their generation to supply AELs Tekapo load islanded from the Grid. Tekapo A power station would be used in the case of the loss of 220 kV supply to Timaru to bolster the weak in-feed from Waitaki to Timaru. Plans are written and held by the region operators to enact this.

The Tekapo GXP utilises an 11 kV circuit breaker (CB32), an 11/33 kV step up transformer and a 33 kV circuit breaker (CB1042) to supply AELs short 33 kV overhead line to the Tekapo Village 33/11 kV zone substation. There is a single 33 kV line from the village sub to Mt Cook (Unwin Hut) and Glentanner.

Transpower have invested in a mobile sub with 110 kV primary connexion and one of 11 or 22 or 33 kV secondary. In 2014 Tekapo A will be equipped to allow the mobile substation to be connected between the Albury 110 kV line and AEL's 33 kV feeder up the hill. A dead change over is required to insert the substation as the phasing is different between the supplies and significant planning is required to expedite to site.

There are various scenarios where AEL can lose supply as alternative supplies are either non-existent or slow to establish.

9.5.2.1 Critical data

The critical GXP data shown in Table 9.41 below, summarises the key physical attributes of the station, the voltages, the capacity, the security, and the power flow.

Table 9.41 Tekapo A Substation key data

GXP	GXP Transmission Potential	GXP Point Of Supply Potential	Capacity	N-1 Capacity	AEL Demand Jun '13
Tekapo A	110 kV	33 kV (via 11 kV bus)	10 MVA	0	3.9 MW

The capacity constraints at the Tekapo A GXP is shown in Table 9.42 below.

Table 9.42 GXP Network constraints

Constraint	Description	Intended remedy
None		

9.5.3 Tekapo A GXP Network information

Figure 9.15 over page, shows the Tekapo A (TKA) GXP area network. There are a number of smaller zone substations to boost voltage to transmit energy to remote sparsely populated areas. Tekapo A acts as a grid injection point for Genesis Energy's hydroelectric power station. From TKA, AEL receives 33 kV which is sub-transmitted to the nearby Tekapo Village (TEK) Zone substation, which also hosts the ripple injection plant. From TEK 33 kV is sub-transmitted to two other zone substation: Glentanner and Unwin Hut. Tekapo Village substation itself supplies the Tekapo township and surrounding rural areas. Two zone substations on two of Tekapo Village substation's feeders: Balmoral and Haldon-Lilybank act as voltage boosters to transmit energy into the remote Haldon, Lilybank, and Simon's Pass areas.

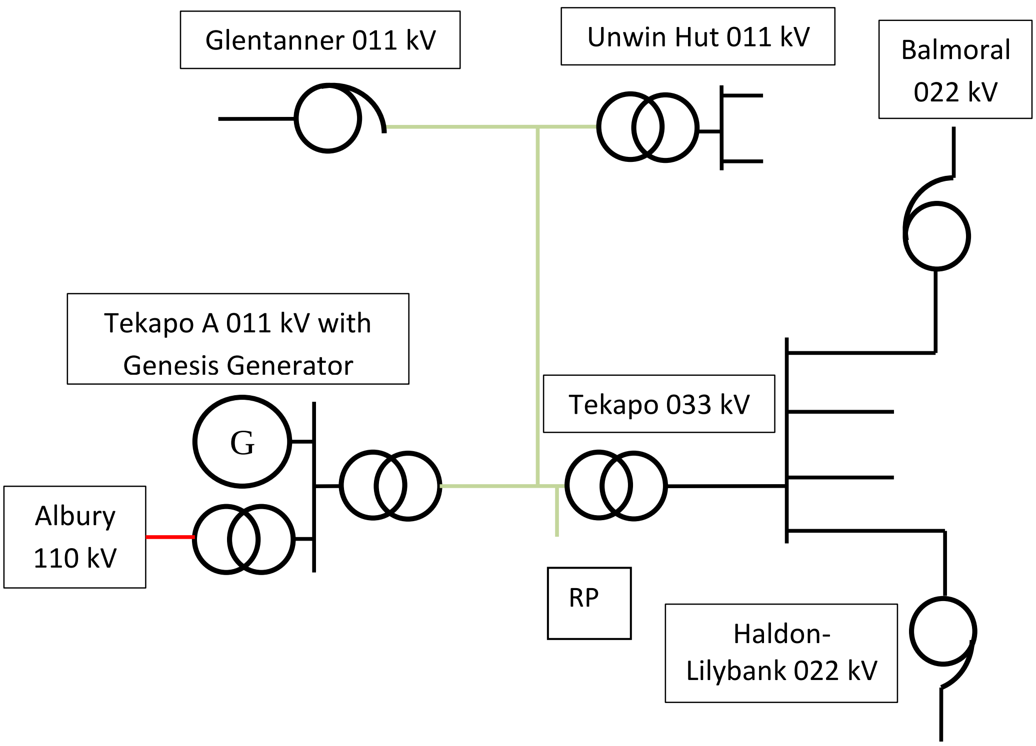
9.5.3.1 Tekapo A-Tekapo Village Sub-transmission

The zone substation key data shown in Table 9.43 over page, details the Tekapo A-Tekapo sub-transmission with respect to rating, age, and general condition.

Table 9.43 TKA-TEK Sub-transmission critical data

Line	Make up	Limit at 6% PD (MVA)	Limit of Conductor at 50 °C (MVA)	Lowest Limit
TKA-TEK	Dog	82.48	12.6	12.6

Figure 9.15 Tekapo A GXP area network



9.5.3.2 Tekapo Village Zone Substation Detail

The Tekapo village zone substation (TEK) key data shown in Table 9.44 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.44 Tekapo Zone Substation key data

Transformer	Switchgear	Ripple Plant
1x 3 MVA (1964) Fair	1x 33 kV Recloser Mt Cook line (1984) Good, 1x 33 kV OCB (T1) (1960) Poor, 7x 11 kV OCBs (1984) Good	Zellweger 500 Hz

Table 9.45 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.45 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Tekapo	Tekapo CBD	N-0.5	N-1	No alternate supply to station.

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
				Limited 11 kV rings. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.
	Mt Cook and Glentanner	N	N	Radial lines and zone substations, no backup. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.
	Tekapo Rural	N	N	Radial lines, no backup. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table 9.46 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.76 at page 285.

Table 9.46 TEK 11 kV Estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
2.6 (Winter / shoulder)	3.4% historic on TKA Residential Load Tourism development	4.8 (Winter / shoulder)	Substation will need upgrade towards end of planning period except demand to grow from current demand of 2.6 MW to about 4.8 MW over planning.

Capacity constraints on AEL's network in the Tekapo Village area network is shown in Table 9.47 below.

Table 9.47 AEL Network constraints

Constraint	Description	Intended remedy
None		

Tekapo Village's Communications are detailed in Table 9.48 below. TEK connects via radio systems detailed in Table 9.48 below.

Table 9.48 Table A16.4 TEK Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	TEK-MRC MRC-WDK		None

Mt Rollesby (MRC) is not AELs site, as this is rented space.

Table 9.49 over page, details TEK's SCADA. L&N C68 RTU equipment installed.

Table 9.49 TEK SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, voltage and CB status at TEK. Security at TEK	TEK CB control. TEK Ripple plant control.	Auto reclosing CB	Load data at TEK

9.5.3.3 Haldon-Lilybank Zone Substation Detail

The Haldon-Lilybank zone substation (HLB) key data shown in Table 9.50 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.50 Haldon/Lilybank zone substation key data

Transformer	Switchgear
1x 1 MVA 22/11 kV OCTC (2009) Excellent	1x 11 kV Eng. Elec. Ball and Chain (1972) Poor

Table 9.51 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.51 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
	Tekapo Rural	N	N	Radial lines, no backup. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table 9.52 below shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.76 at page 285.

Table 9.52 Estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
0.2 (Est.) (Winter / shoulder)	3.4% 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.

Table 9.53 over page, shows the capacity constraints on AEL network in the Haldon and Lilybank areas.

Table 9.53 AEL Network constraints

Constraint	Description	Intended remedy
Lines away	Light two phase, large spans	Feed Haldon from TWZ.

No communications installed on site. Detail in Table 9.54 below.

Table 9.54 HLB Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
Vehicle radio	None	None	None

No SCADA installed on site, shown in Table 9.55 below.

Table 9.55 HLB SCADA summary

Supervision	Control	Automation	Data Acquisition
None	None	None	None

9.5.3.4 Balmoral (BMR) Zone Substation detail

The Balmoral zone substation (BMR) key data shown in Table 9.56 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.56 Balmoral Zone Substation key data

Transformer	Switchgear
1x 0.6 MVA 22/11 kV OCTC (Aged) Fair	1x 33 kV Scarpa Magnano (Aged) Poor (run at 22 kV) 1x 11 kV DDO type fuse

Table 9.57 over page, lists the existing level of security at the substation and justifies any shortfall.

Table 9.57 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
	Tekapo Rural	N	N	Radial lines, no backup. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table 9.58 over page, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.76 at page 285.

Table 9.58 Estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
0.3 (Est.) (Winter / shoulder)	3.4% 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.

Table 9.59 below, shows the capacity constraints on AELs network in the Balmoral area network.

Table 9.59 AEL Network constraints

Constraint	Description	Intended remedy
Lines away	Light three phase, large spans	Feed Simon's Pass from TWZ.

No communications installed on site. Detail in Table 9.60 below.

Table 9.60 BMR Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
Vehicle radio	None	None	None

No SCADA installed on site. Detail in Table 9.61 below.

Table 9.61 BMR SCADA Summary

Supervision	Control	Automation	Data Acquisition
None	None	None	None

9.5.3.5 Mt Cook Station Tee-Tekapo Village Sub-transmission

The zone substation key data shown in Table 9.62 below, details the Tekapo Village-Mt Cook Station sub-transmission with respect to rating, age, and general condition.

Table 9.62 Mt Cook Station Tee-TEK sub-transmission critical data

Line	Make up	Limit at 6% Volt Drop (MVA)	Limit of Conductor at 50 °C (MVA)	Lowest Limit
Mt Cook Stn Tee-TEK	Dog/Flounder	2.25	12.6 8.6	2.25

9.5.3.6 Glentanner Sub-transmission-Mt Cook Station Tee Line

The zone substation key data shown in Table 9.63 over page, details the Glentanner Sub-Mt Cook station Tee Sub-transmission with respect to rating, age, and general condition.

Table 9.63 GTN-Mt Cook sub-transmission critical data

Line	Make up	Limit at 6% PD (MVA)	Limit of Conductor at 50 °C (MVA)	Lowest Limit
GTN-Mt Cook	Mink	6.84	10.3	2.25 (from Mt Cook 6% PD)

9.5.3.7 *Glentanner Zone Substation detail*

The Glentanner zone substation (GTN) key data shown in Table 9.64 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.64 Glentanner Zone Substation key data

Transformer	Switchgear
0.6 MVA 33/11 kV (1986) OCTC Fair	1x 11 kV Eng. Elec. Ball and Chain (1972) Poor 1x 33 kV DDO type fuse

Table 9.65 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.65 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Tekapo A	Glentanner	N	N	Radial lines and zone substations, no backup. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table 9.66 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.76 at page 285.

Table 9.66 Estimated demand at zone substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
0.3 (Est.) (Winter / shoulder)	3.4% 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.

Table 9.67 over page, shows the capacity constraints on AELs network in the Glentanner area network.

Table 9.67 AEL Network constraints

Constraint	Description	Intended remedy
None		

No communications installed on site. Detail in Table 9.68 below.

Table 9.68 GTN Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
Vehicle radio	None	None	None

No SCADA installed on site. Detail in Table 9.69 below.

Table 9.69 GTN SCADA summary

Supervision	Control	Automation	Data Acquisition
None	None	None	None

9.5.3.8 Mt Cook Station Tee-Unwin Hut Sub-transmission

The zone substation key data shown in Table 9.70 below, details the Tekapo Village-Mt Cook Station Tee sub-transmission with respect to rating, age, and general condition.

Table 9.70 Mt Cook Stn Tee-UHT Sub-transmission critical data

Line	Make up	Limit at 6% Volt Drop (MVA)	Limit of Conductor at 50 °C (MVA)	Lowest Limit
Mt Cook Stn-UHT	Mink/Petrel	1.2	10.3 11.4	1.2

9.5.3.9 Unwin Hut (UHT) Zone Substation detail

The zone substation key data shown in Table 9.71 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.71 Unwin Hut Zone Substation key data

Transformer	Switchgear
1x 1.5 MVA OLTC 33/11 kV (1974) Fair	1x 33 kV OCB (1974) Fair 2x 11 kV OCBs (1977)Good

Table 9.72 over page, lists the existing level of security at the substation and justifies any shortfall.

Table 9.72 Unwin Hut Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Tekapo A	Mt Cook	N	N	Radial lines and zone substations, no backup. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table 9.73 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.76 at page 285.

Table 9.73 Unwin Hut estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
1.0 (Est.) (Winter / shoulder)	3.4% historic on TKA Residential Load Tourism development	(Winter / shoulder)	0.5 MW in transformer and 0.2 MW in line run hard with accentuated voltage drop.

Table 9.74 below, shows the capacity constraints on AEL's network in the Unwin Hut area network.

Table 9.74 AEL Network constraints

Constraint	Description	Intended remedy
None		

UHT connects via two radio systems detailed in Table 9.75 below.

Table 9.75 Unwin Hut communications

VHF	UHF Analogue	UHF Digital
VHF for voice traffic VHF for two bit alarms	None	None

At Unwin Hut Zone Sub, SCADA consists of a Two bit alarm via VHF.

9.5.4 Development of GXP and Substations

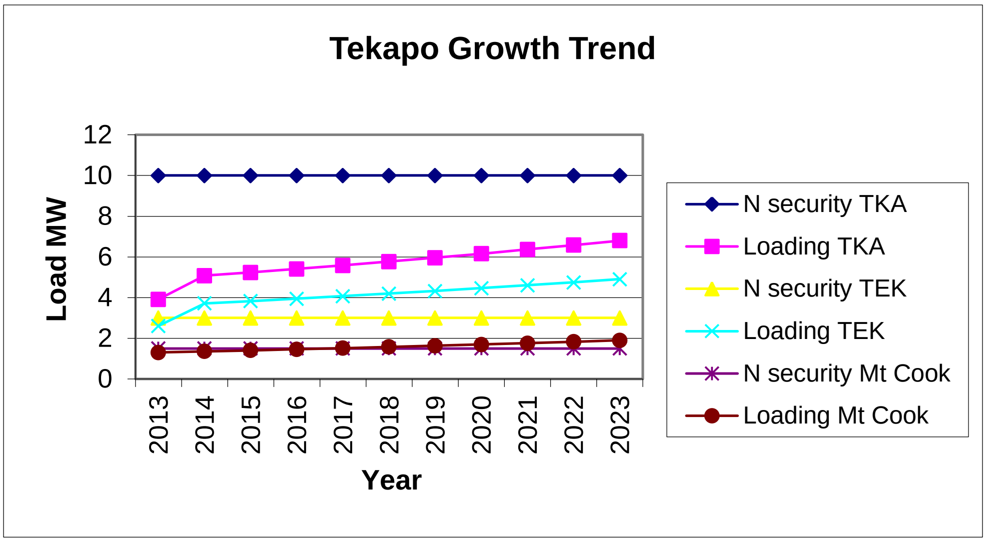
Table 9.76 below shows the growth trend to the year 2024.

Table 9.76 Substation load growth

GXP Substation (Season Peak)	Growth Trend (Total MW MD										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Tekapo Sum (Autumn/Spring)	5.0	5.2	5.3	5.5	5.6	5.8	5.9	6.1	6.2	6.4	6.6
TEK Village	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.8
Mt Cook and Glentanner	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8

Figure 9.16 below, shows the maximum demand history to date the almost six percent load growth anticipated in the tourism sector in 2009, had fallen back to nearer 3.5% looking into the immediate future. Recently, there appeared to have been a halt to the proposed CBD development due to the economic recession. This CBD development will recommence in 2014.

Figure 9.16 Studholme Growth trend



9.5.4.1 Substation Growth Trend and Supply Security

The anticipated load growth in the tourism sector has fallen back to nearer 4% from 6%. The CBD development will commence in 2014 for which AEL has allowed 1 MW of load. AEL are unsure of the speed of the take up of this.

AEL's supply is on an N basis from Tekapo A. An 11 kV bus or 11 kV to 33 kV step up transformer fault would result in a total supply loss until repairs were affected. Since the spare transformer is not on site a fault within the transformer would result in a loss of supply of at least a day while a change out occurred. The proposed project between Transpower/Genesis (was Meridian) to alter the 11 kV bus to give added security has been cancelled.

9.5.4.2 Rate and Nature of GXP Growth and Provisions made

Table 9.77 below, summarises the characteristic of the growth and summarises the plans to meet the energy requirements of the growth.

Table 9.77 Growth and response

GXP	Rate and nature of growth	Provisions for growth
Tekapo A	Med – subdivision and tourism business	Upgrade Zone sub

9.5.4.3 Specific Developments

Tekapo A Transpower 11 kV switchboard

Transpower look to carry out a strengthening and arc flash containment project on the switchboard in 2014. This will extend the life of the existing switchboard in the same electrical configuration.

Haldon-Lilybank Zone Substation Upgrade

Haldon-Lilybank is a small step up substation on the edge of Tekapo, it consists of a ball and chain recloser, an 11/22 kV step up auto transformer and two phase lines away to Haldon and Lilybank. The neutral of the autotransformer has earth fault protection installed.

The substation is due for replacement. Options are being examined.

An enquiry has been made from a number of farmers about a stronger supply in the Haldon area for irrigation. The 22 kV system is not three phase and does not have capacity. The most economical solution for this is taking a supply from Twizel. In the meantime the farmers are still developing the proposal, and there is no time frame given for the irrigation to be commissioned.

Balmoral Zone Substation Upgrade

Balmoral is a small step up substation on the edge of Tekapo that feeds Simon’s Pass, it consists of: a primary 11 kV fuse; an 11/22 kV step up auto transformer; a 33 kV 600 A Scarpa Magnano minimum oil CB; and post CTs, and a 22 kV line away. The neutral of the autotransformer has earth fault protection installed.

There are thoughts that the substation may be disestablished, the 22 kV line operated at 11 kV, and the several existing 22 kV distribution transformers replaced with standard 11 kV distribution transformers. However, there a pause in this work while irrigation prospects in the Simon’s Pass/Pukaki area are fully identified to AEL.

Ripple plant upgrade

A 10 year program to replace or decommission the old rotating ripple injection plants was commenced in 2000 although TKA still has rotary ripple plants. This was delayed 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 equipment. Therefore it has been decided to recommence the original plan to replace the old rotary injection plants with modern electronic equipment as per the original program.

9.5.4.4 Issues Arising from Estimated Demand

Transpower have identified the supply transformer becoming too small in 2022, this is because the 10 MVA transformer is constrained via protection/metering, some changes will be required to extend the capacity of the transformer.

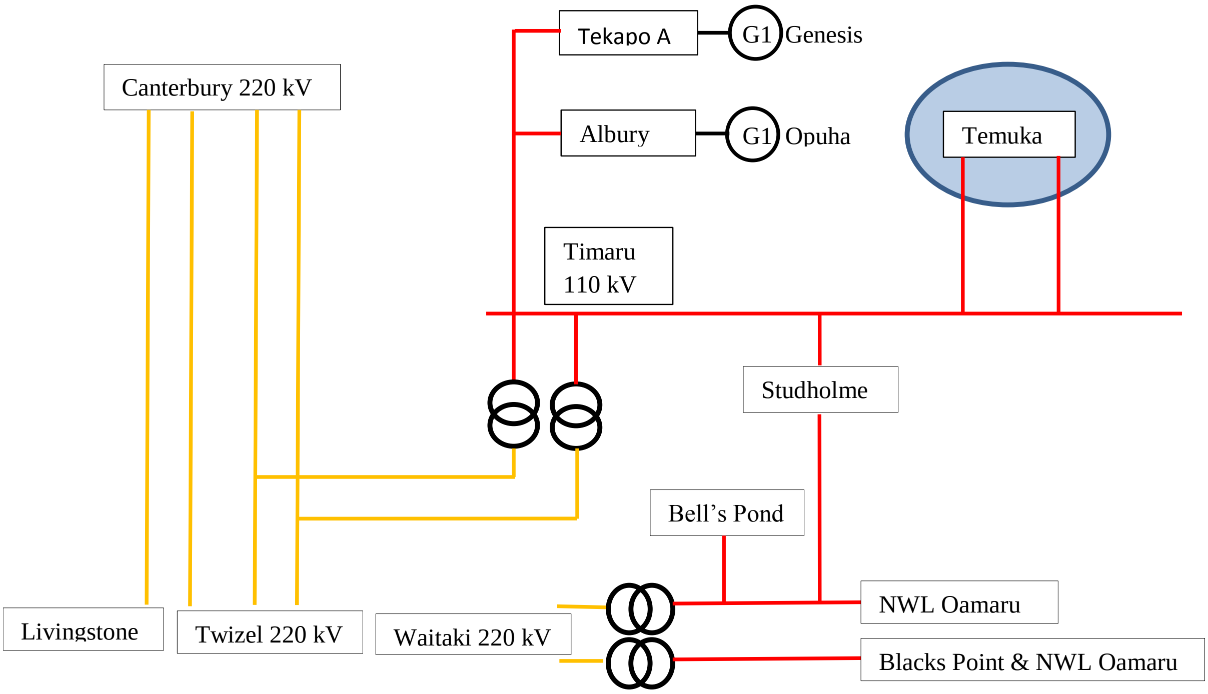
Meridian used to black start their generator to provide an alternate electricity supply, AEL are unsure if the new owner, Genesis, offer black starting. Transpower are confirming the arrangement.

9.6 Temuka Grid Exit Point

9.6.1 Introduction

Figure 9.17 below, shows how the Temuka GXP (TMK) is configured with our network and Transpower's transmission network. Temuka is supplied by double 110 kV transformer feeder circuits from Timaru's 110 kV bus.

Figure 9.17 GXP configuration.



9.6.2 GXP Description

Figure 9.18 at page 323, shows the Temuka (TMK) GXP area network. The 110/33 kV GXP has eight 33 kV feeders: four to Fonterra's Clandeboye Dairy Factory (of which two are direct cables and two are overhead circuits supported on a single pole line); two 33 kV cables to AELs 33/11 kV zone substation (co-sited at the Temuka GXP); one 33 kV circuit breaker to supply an overhead 33 kV feeder to Geraldine; and one 33 kV circuit breaker to supply an overhead 33 kV feeder to Rangitata. The latter two have a tying arrangement at the end of the CB cable/start of overhead line to give security for a CB failure. The AEL 33/11 kV zone substation supplies the Temuka township and surrounding rural area.

Peak demand occurs during summer based on the predominant dairy and irrigation load.

9.6.2.1 Critical data

The critical GXP data shown in Table 9.78 over page summarises the key physical attributes of the station, the voltages, the capacity, the security, and the power flow.

Table 9.78 Temuka Sub key data

GXP	GXP Transmission Potential	GXP Point Of Supply Potential	Capacity	N-1 Capacity	AEL Demand Jan '13
Temuka	110 kV	33 kV	120 MVA	60 MVA[19]	52 MW

Table 9.79 below shows the capacity constraints in the Temuka GXP.

Table 9.79 GXP Network constraints

Constraint	Description	Intended remedy
Temuka Area - Holistic	Lack of capacity for TMK 33 kV GXP load	Work with Transpower on upgrading supply assets. Possibly establish new GXP off a proposed 220 kV Orari bussing point. Possibly establish new GXP at TMK off a 220 kV line diversion to TMK.
Temuka GXP Supply Security	Load constraint over 60 MVA transformers, 70 MVA on lines, 71 MVA 33 kV switchboard	New investment in line and switchboard upgrade – Transpower discussion (timing uncertain). Possibly establish new GXP off a proposed 220 kV Orari bussing point to offload Temuka GXP. Possibly establish new GXP at TMK off a 220 kV line diversion to TMK.

9.6.3 Temuka GXP Network information

Figure 9.18 over page, shows the TMK GXP network area.

The AEL TMK 33/11 kV zone substation supplies the Temuka township and surrounding rural area. Peak demand occurs during summer based on the predominant dairy and irrigation load.

9.6.3.1 Temuka (TMK) Zone Substation detail

The zone substation key data shown in Table 9.80 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.80 Temuka Zone Substation key data

Transformer	Switchgear	Ripple Plant
2x 25 MVA OLTC 33/11 kV (2007) Good	9x 11 kV VCBs (2006) Excellent	1x Zellweger 317 Hz 33 kV

[19] The Transpower GXP 110/33 kV transformers were uprated from 51 MVA to 60 MVA in 2010

Figure 9.18 Temuka GXP area network

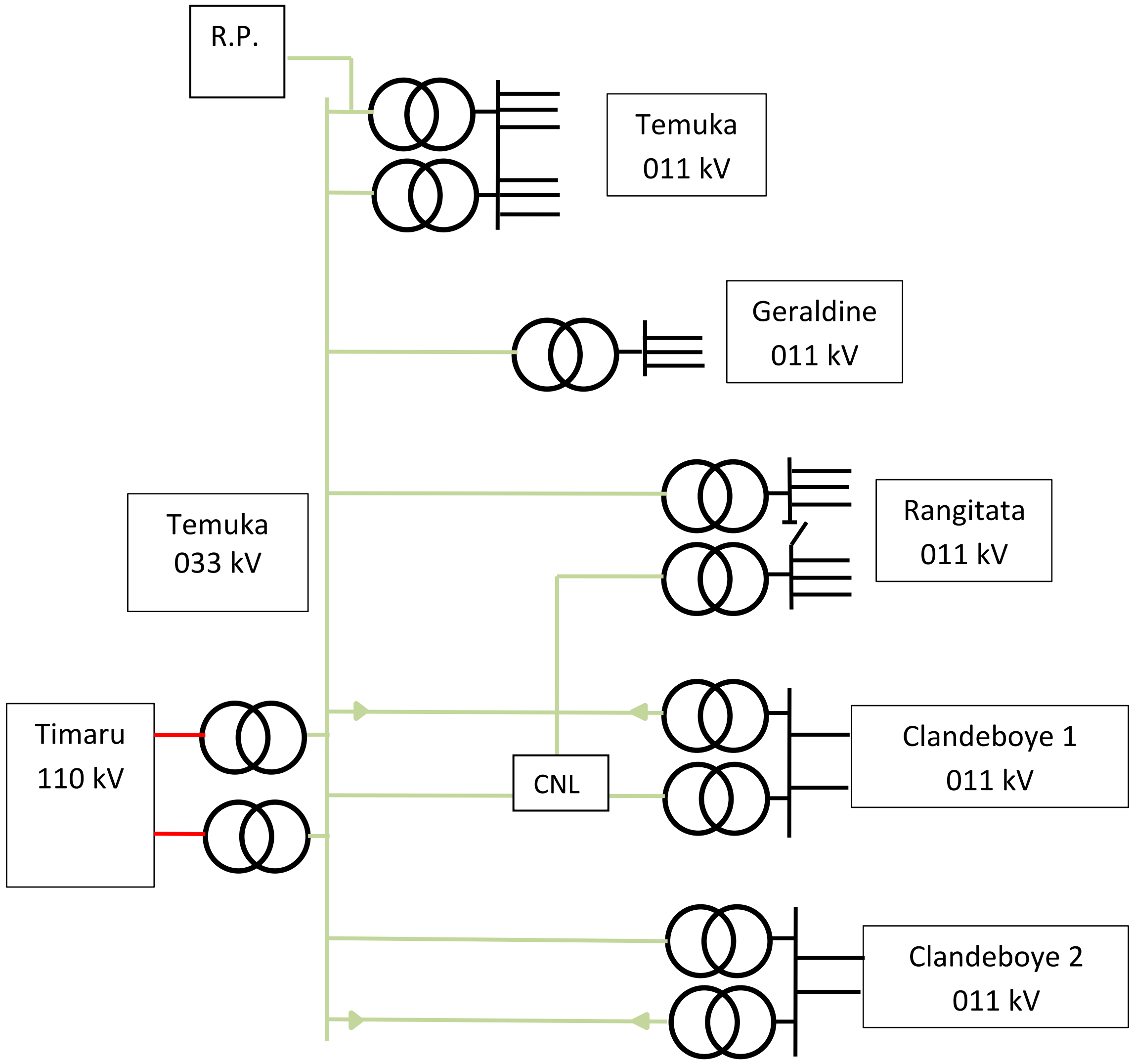


Table 9.81 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.81 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Temuka	Temuka Residential	N-1	N-1	Capacity headroom eroding due to commercial developments fed via the residential area. Look to increase size of conductor to limit volt drop, difficult through residential area due to Council planning constraints for overhead lines.

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
	Temuka Rural	N-0.5	N-0.5	Limited fault backup from GLD, RGA, PLP and TIM. Encourage customers to be self–sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table 9.81 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.107 at page 299.

Table 9.82 TMK estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
52 (summer)	3.175% historic on TMK Residential load Dairy and irrigation development Dairy processing	85.5 (summer)	Load growth due to expansion at Clandeboye which is not yet confirmed. If realised this would require a transmission solution to be discussed with Transpower.

Table 9.83 below, shows the capacity constraints on AEL's network in the Temuka area network.

Table 9.83 AEL Network constraints

Constraint	Description	Intended remedy
GXP Constraints	As described in Table 2	As described in Table 2

TMK connects via radio systems detailed in Table 9.84 below.

Table 9.84 TMK Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	None	TMK-MEC MEC-WDK (main) TMK-WDK (backup)	CD2-TMK (services CD1and2 and CNL)

TMK is a communications hub for CD1, CD2 and CNL. TMK's communications room has had oil filled switchgear and transformers removed from it to reduce risk to the equipment.

An Abbey RTU connects to the AEL 11 kV switchgear and transformer zone IEDs, controls the ripple plant, and connects to Transpower's data bridge to their RTU in their 33 kV switch room. Detail in Table 9.85 below.

Table 9.85 TMK SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, voltage and CB status at TMK. Security at TMK	TMK CB and Transformer Control. Ripple plant control.	Auto Reclosing CB	Load data at TMK

9.6.3.2 Temuka-Clandeboye Sub-transmission

The zone substation key data shown in Table 9.86 below, details the Temuka–Clandeboye 1 and Clandeboye 2 substation sub-transmission with respect to rating, age, and general condition.

Table 9.86 TMK-CD1 and CD2 Sub-transmission critical data

Line	Make up	Limit at 6% Volt Drop (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable	Lowest Limit
TMK-CD 1	Cable 1/400 then 1/300	42.3		21.3	21.3
TMK-CD 2	Cable 2x1/300/ Jaguar then 1/300	33	23.4	21.3	21.3
TMK-CD 3	Cable 2x1/300/ Jaguar then 1/400	33	23.4	24.2	23.4
TMK-CD 4	Cable 1/400	42.3		24.2	24.2

9.6.3.3 Clandeboye 1 and Clandeboye 2 Zone Substation detail

The zone substation key data for Clandeboye 1 and 2 (CD1 and CD2 respectively) shown in Table 9.87 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.87 Clandeboye 1 and 2 Zone Substation key data

Substation	Transformer	Switchgear
Clandeboye 1 (14 MW)	2x 20 MVA OLTC 33/11 kV (1997) Good	2x 33 kV Reclosers WVE (1997) Good 15x 11 kV VCBs (1997) Excellent
Clandeboye 2 (14 MW)	2x 25 MVA OLTC 33/11 kV (2004) Excellent	2x 33 kV Recloser VWVE (2004) Good 12x 11 kV VCBs (2004) Excellent

Table 9.88 over page, lists the existing level of security at the substation and justifies any shortfall.

Table 9.88 Security level

GXP	Zone Sub /	Actual	Target	Shortfall from target

	Load Centre			
Temuka	Clandeboye 1 and 2	N-2 (Sub-Trans) N-1 (GXP)	N-2	Fonterra invested with the additional installation of two 33 kV cables to their plant in addition to the two 33 kV overhead circuits that were initially installed. The source from Transpower to the TMK GXP consists many components and is an N-1 supply. Discussion with Transpower held to try to reduce the number of components when the Orari bussing project occurs.

The estimated demand listed in Table 9.89 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.107 at page 299.

Table 9.89 CD1 and CD2 estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
25 (summer)	3.175% historic on TMK Process Expansion and new Dryer	35 (summer)	Substation and sub-trans capacity available. Additional CB's at substations and 11 kV cabling to new RMU and Dist Tx's required – expect demand to grow from current demand of 25 MW to about 45 MW by the end of the planning period. Existing assets can meet this demand and retain n-1 security.

Table 9.90 below, shows the capacity constraints on AELs network in the Clandeboye area network.

Table 9.90 AEL network constraints

Constraint	Description	Intended remedy
GXP Constraints	As described in Table 2	As described in Table 2

CD1 and CD2 connect via fibre optic cable detailed in Table 9.91 below.

Table 9.91 CD1 and CD2 communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	None	CD1-CNL (services CNL)	CD2-TMK (services CD2) CD1-CD2 (services CD1)

CD2 is a communications hub for CD1 and CNL.

SCADA consists of Dual SEL 3530; connects to the IEDs at both CD1 and CD2. Detail is shown in Table 9.92 below.

Table 9.92 CD1 and CD2 SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, Voltage and CB status at CD1 and CD2. Security at CD1 and CD2	CD1 and CD2 CB and Transformer Control.	Control of CBs	Load data at CD1 and CD2

9.6.3.4 Canal Road Switching Substation detail

The switching substation key data for Canal Road (CNL) is shown in Table 9.93 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.93 Canal Road Zone Substation key data

Switching station	Transformer	Switchgear
CNL (8.5 MW)	None	1x 33 kV GL107X CB (SF_6) (2012) Excellent

Table 9.94 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.94 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Temuka	Rangitata	N	N	Station allows connexion to TMK-CD1 cct 2 for supply to RGA. RGA has security via TMK's direct circuit. See RGA for further detail.

CNL communications connect via radio detailed in Table 9.95 below.

Table 9.95 CNL Communications Summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	None	CD1-CNL	None

CNL SCADA consists of an SEL 3530 and connects to the IEDs. This is detailed in Table 9.96 below.

Table 9.96 CD1 and CD2 SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, voltage and CB status at CNL. Security at CNL.	CNL CB Control.	Control of CB	Load data at CNL

9.6.3.5 Temuka-Rangitata Sub-transmission

The zone substation key data shown in Table 9.97 below, details the Temuka-Rangitata sub-transmission with respect to rating, age, and general condition.

Table 9.97 TMK-RGA Sub-transmission critical data

Line	Make up	Limit at 6% Volt Drop (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable	Lowest Limit
RGA 1-TMK	Cable 1/400 /Dog/Iodine/Mink Cable 3/95/Wolf Core	8.4	10.3	11.5	8.4
RGA 2-TMK via Canal Rd teed off CD2-TMK 10 MVA take agreed with Fonterra	Cable 2x1/300/ Jaguar	21.26 (14.95 towards RGA2)	23.4	32	10

AEL have an agreed limit of 10 MVA take off the CD1-TMK 33 kV circuit.

9.6.3.6 Rangitata (RGA) Zone Substation detail

The zone substation key data shown in Table 9.98 below, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.98 Rangitata Zone Sub key data

Substation	Transformer	Switchgear
Rangitata (8.5 MW)	2x 9/15 MVA OLTC 33/11 kV (2011, 2012) Excellent	2x 33 kV GL107X CB (SF_6) (2011, 2012) Excellent 5x 11 kV VCB Tamco (2004) Excellent 5x 11 kV VCB RPS (2011) Excellent

Table 9.99 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.99 Security Level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Temuka	Rangitata	N-0.5	N-1	Station runs with split 11 kV bus, 8.4 MVA available at worst after switching. Balance can be shifted onto 11 kV backup from GLD and TMK.

The estimated demand listed in Table Table 9.100 over page, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.107 at page 299.

Table 9.100 RGA estimated demand at Zone Sub level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
8.5 (summer)	3.175% historic on TMK Residential load Dairy and Irrigation development	13.5 (summer)	33 kV circuit is prepared to provide (n-1) security; expect demand to grow from current demand of 7 MW to about 13.5 MW by the end of the planning period. Note some of RGA load can be transferred to Temuka and Geraldine as a temporary measure.

Table 9.101 below, shows the capacity constraints on AELs network in the Rangitata area network.

Table 9.101 AEL Network constraints

Constraint	Description	Intended remedy
Rangitata 33 kV sub-trans 1 line regulation	Voltage constraint over 8.4 MVA of load (6% volt drop)	Second 33 kV feeder to Rangitata took load in 2013. For a sub-trans tripping shuffling of load required, most can be done via remote control so quick response. Long term sub-trans review required.

9.6.3.7 Geraldine-Temuka Sub-transmission

The zone substation key data shown in Table 9.102 below, details the Geraldine-Temuka sub-transmission with respect to rating, age, and general condition.

Table 9.102 GLD-TMK Sub-transmission critical data

Line	Make up	Limit at 6% Volt Drop (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable	Lowest Limit
GLD-TMK	Cable 1/400 /Dog	8.64	12.6	24.2	8.64

9.6.3.8 Geraldine (GLD) Zone Substation detail

The zone substation key data shown in Table 9.103 over page, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.103 Geraldine zone substation key data

Substation	Transformer	Switchgear
Geraldine (6 MW)	1x 5/6.25/9 MVA OLTC 33/11 kV (1980) Good	1x 33 kV Recloser VWVE, T2 (2009) Excellent 1x 11 kV Recloser U Nulec, T2 (2009) Excellent 3x 11 kV Recloser U Nulec, feeders (2007) Excellent

Table 9.104 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.104 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Temuka	Geraldine	N-0.5	N-0.5	33 kV investment to be considered. Watch Transpower's proposal for an Orari 220 kV bussing point. May free a circuit passing near GLD on the TMK-RGA Cct 1 for use at GLD.

The estimated demand listed in Table 9.105 below, shows the aggregated effect of substation demand growth for a 10-year horizon incorporating the anticipated step changes detailed in Table 9.107 at page 299.

Table 9.105 Estimated demand at zone substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
6.5 (summer)	3.175% 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.

Table 9.106 below, shows the capacity constraints on AELs network in the Geraldine area network.

Table 9.106 AEL Network constraints

Constraint	Description	Intended remedy
Geraldine 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 on RGA depending final irrigation scheme load
Geraldine CBD	Voltage constraint at end of feeder	Install capacitor 2014/15 plan, review required

9.6.4 Development of GXP and Substations

Table 9.107 below, shows the growth trend to the year 2022.

Table 9.107 Substation load growth

GXP Substation (Season Peak)	Growth Trend (Total MW MD)										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Temuka (Summer)	58.2	63.5	65.6	66.9	68.2	69.6	79.0	80.5	82.1	83.8	85.5

The above trend shows that the Temuka 33 kV GXP load will exceed the secure supply capacity in 2015. AEL hoped for an introduction of a new GXP at Orari (with Transpower's 220 kV bussing project for the upper South Island) for transformer feeders to be built to Clandeboye, Rangitata's load could have been applied to the new supply bus. Transpower bussing project seems to have been put back to 2022 (revised 2013).

The 2015 prediction above was 2019 but the Rangitata South Irrigation scheme installed more than twice the transformers than first informed, 3 to 4 MVA request increased to 9 MVA. AEL are yet to see a full irrigation season run as the ponds are still filling and water is only being made available from 2014. 2015 should see Rangitata South's conclusion.

Other options to reduce the load on Temuka or bring a direct 220 kV supply need to be examined in the near future.

Fonterra has advised a new cheese plant will be commissioned in 2015 and that the new Clandeboye drier (D4) is on hold pending developments at the Darfield plant. AEL has however factored in additional drier load around 2021. Studies need to be carried out to ensure that the load growth that is presently being experienced doesn't curtail with the land becoming fully irrigated. All the farms must at some stage be "wet" and no more dairy sheds able to be built. More research is required. Fonterra can build driers faster than Transpower can respond to capacity increases.

Transpower has included possible upgrades at Temuka to install one 120 MVA transformer and parallel the two existing. This would best be done onto a new two bus-section 33 kV switchboard as the existing one is only rated to 71 MVA.

The 110 kV lines to Temuka from Timaru are rated 70 MVA, with either some lifting to provide better ground clearance or re-conductoring, they could be rerated to allow more power flow. Transpower has also identified the need to upgrade these lines to supply the new transformer arrangement at Temuka.

9.6.4.1 Substation Growth Trend and Supply Security

Temuka GXP is reaching capacity. Either ourselves and or Transpower will decide on a solution.

9.6.4.2 Rate and Nature of GXP Growth and Provisions made

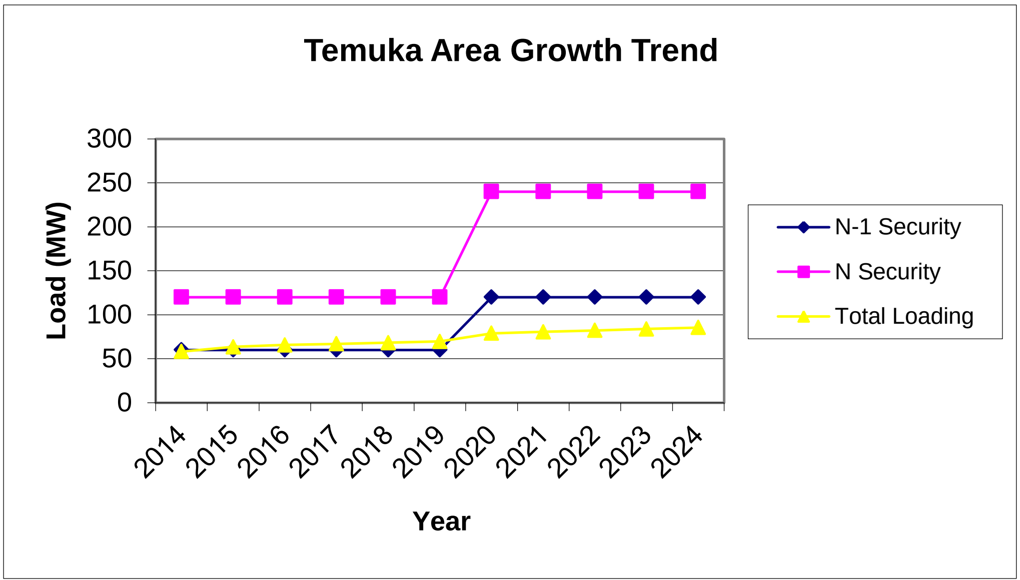
Table 9.108 below, summarises the characteristic of the growth and summarises the plans to meet the energy requirements of the growth.

Table 9.108 Growth and response

GXP	Rate and nature of growth	Provisions for growth
Temuka	High – rural and industrial	GXP investment

Figure 9.19 below, shows the growth trends in the Temuka GXP area.

Figure 9.19 Temuka Area load growth and supply security



9.6.4.3 Specific Developments

Temuka 110/33 kV GXP

Temuka has two 110/33 kV transformer feeders from Timaru supplying the 33 kV bus. The 110 kV lines are rated at 70 MVA and the transformers 60 MVA. AEL has a peak load of 52 MVA (Jan 2013). A large number of additional loads will be realised with future dry years and Rangitata South's irrigation scheme being run hard.

If there was a loss of one of the 110 kV transformer feeders from Timaru the remaining transformer would be running without spare capacity during peak load periods. Replacement of the transformers has been delayed.

AEL had looked at establishing a 220 kV GXP at Orari at the "Geraldine bussing site" but the development of the bussing project has been delayed which in turn would put a lot of the cost of the Orari site onto AEL. This is not palatable. AEL will work further with Fonterra to identify their development needs and then in turn with Transpower to identify the timing and nature of the required upgrade to meet demand.

Another option Transpower has posed, but is yet to discuss, is the possibility of diverting 220 kV to the site. The Livingstone-Islington circuit is the closest. AEL has seen a serious limitation proposed to the load offered in the Waimate area off the Livingstone-Islington circuit so have doubts Transpower have looked at this holistically. The idea is sound as it would save expenditure on the chain, Timaru T5 and T8, Timaru 110 kV bus strengthening, Temuka-Timaru 110 kV line reinforcement, install 220 kV primary rated transformers rather than the one 110 kV primary rated transformers. The existing transformers could be released for other duties. The same 33 kV bus would be required. Some of the costs savings to the Grid, T5 and T8 and Timaru's 110 kV bus should be transferred to this project if it proceeds.

9.6.4.4 Issues Arising from Estimated Demand

Up to 2009 AEL and Transpower held ongoing discussion regarding the strengthening of the Temuka GXP, this has waned in recent times. AEL's load predictions now show the spare capacity at Temuka consumed with the last spare room to be taken by South Rangitata's irrigation and Clandeboye's C21 extension.

AEL had hoped for a fast resolve when Orari's 220 V bussing point was to be built in 2017 – this timeframe is extended to possibly 2022 with no firm date known. AEL were hopeful of being able to take two 220 kV circuits to a new GXP in the vicinity of Clandeboye to offload their 25 MW load and look to connect AEL's two Rangitata zone substations as well. A total of 40 MW load being offloaded from the undersized Timaru T5 and T8 and the string of assets to Temuka and beyond would be beneficial. AEL were offered the choice of going it alone to build the Orari assets but the cost was uneconomic.

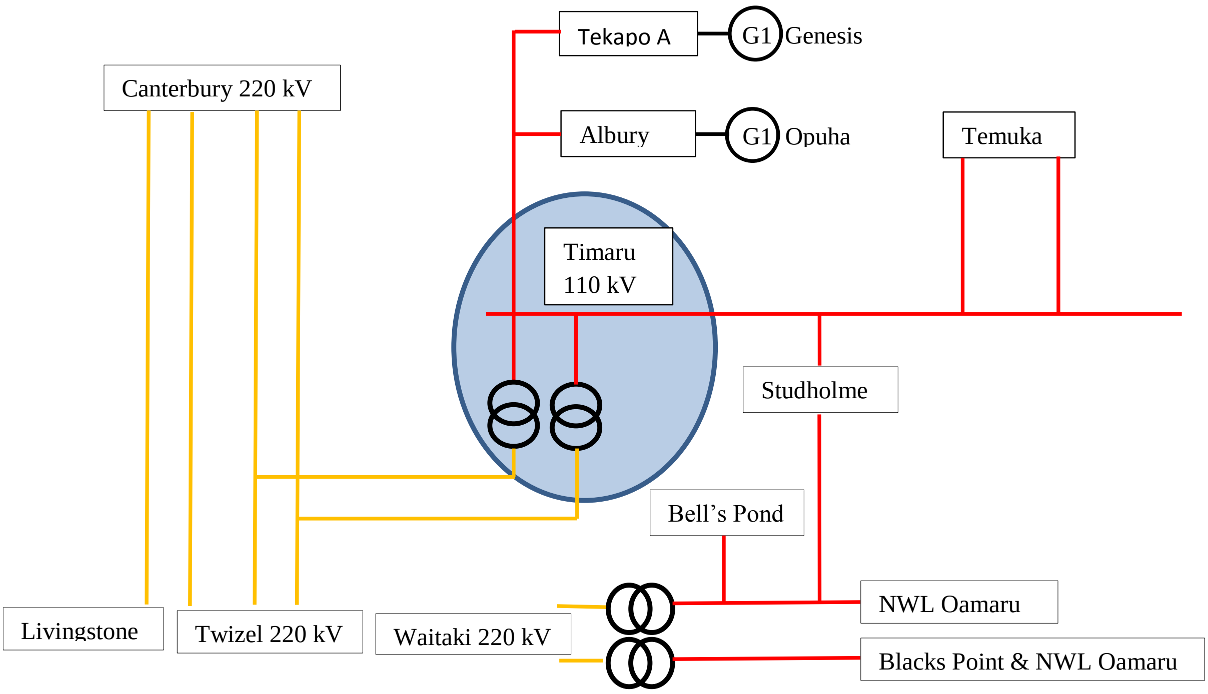
For now there is no clear solution for Temuka, though AEL is interested in asking (when time permits) if the Livingstone-Islington 220 kV circuit can be diverted to Temuka via a double circuit for an in/out bus and two new supply transformers and 33 kV bus. This would leave Clandeboye and Rangitata with a 33 kV supply from Temuka. Some 33 kV line/cable work would be required to secure the upcoming loads. Timaru's interconnection 220/110 kV transformers and the string of assets around them and to Temuka would be offloaded.

9.7 Timaru Grid Exit Point

9.7.1 Introduction

Figure 9.20 below, shows how Timaru GXP (TIM) is configured with our network and Transpower's transmission network. Timaru GXP is supplied by 220 kV Twizel-Islington (via Ashburton) double circuit to Timaru's 110 kV bus via T5 and T8 interconnecting transformers.

Figure 9.20 GXP configuration



9.7.2 GXP Description

Timaru GXP is the largest supply point connecting two 220/110 kV interconnectors to provide a 110 kV bus which acts as a transmission hub for Albury, Tekapo, Temuka and Studholme/Bell's Pond. The 110 kV is stepped down through three transformer banks to supply the 11 kV switch-board at Timaru.

The 11 kV switchboard at Timaru was replaced in early 2012 as it was at end-of-life. On the new (2012) switchboard, the 11 kV is split across 20 feeder circuit breakers.

Two are stepped up to 33 kV by AEL to supply three single circuit 33 kV lines: two 10 km circuits to Pareora zone substation supplying a 5 MW meat works and a rural load, and one 12 km circuit supplying a rural community at Pleasant Point zone substation for township and rural customers.

Six 11 kV sub-transmission cables supply some 35 MW to the CBD area. These include four cables to Grasmere St 11 kV switching substation, which then supplies cables to Hunt St and North St 11 kV switching stations, and two additional cables to the North St 11 kV switching station. Each of these three switching station has an indoor switchboard with between eight and 12 cable feeders each, supplying into the CBD, port, and surrounding residential areas.

Timaru GXP also supplies twelve 11 kV feeders to both the western residential areas and the northern residential and industrial areas of Washdyke and the 4 MW meat works at Smithfield.

In addition, there are two 11 kV CBs allocated for connecting new ripple control plant and AEL local service transformer supplies.

The 110/11 kV transformer banks at Timaru are being replaced as they are at end-of-life. Due to load growth, the transformers cannot support N-1 security. AEL is discussing with Transpower options for Timaru with a clear long term engineering solution being for development of a 33 kV supply to complement the 11 kV supply in the next 10 years, depending upon load growth.

As AELs load grows in the Port and Washdyke areas, a 33/11 kV zone substation in each area will be required to support the development. When these zone substations are developed the 33 kV POS will be taken from Transpower. Timing at present is uncertain given the economic climate.

At Timaru, peak demand occurs during winter due to the dominant residential load.

9.7.2.1 Critical data

The critical GXP data shown in Figure 9.21 over page, Table 9.109 below, summarises the key physical attributes of the station, the voltages, the capacity, the security, and the power flow.

Table 9.109 Timaru Substation key data

GXP	GXP Transmission Potential	GXP Point Of Supply Potential	Capacity	N-1 Capacity	AEL Demand Jun '13
Timaru	110 kV	11 kV	82 MVA	54 MVA	62 MW

Table 9.113 at page 306, shows the capacity constraints in the Timaru GXP.

9.7.2.2 Timaru (TIM) (Grant's Hill) Zone Substation detail

The zone substation key data shown in Table 9.110 at page 305, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided. Timaru zone substation was historically referred to as Grant's Hill. The substation's purpose is to step up 11 kV to 33 kV to feed Pareora zone substation and Pleasant Point zone substation. The site also hosts the ripple plant. Transpower switchgear onsite feeds the surrounding rural, residential, and Washdyke/Seadown areas.

9.7.3 Timaru GXP Network information

Figure 9.21 below, shows the Timaru GXP area network.

Figure 9.21 Timaru GXP area network

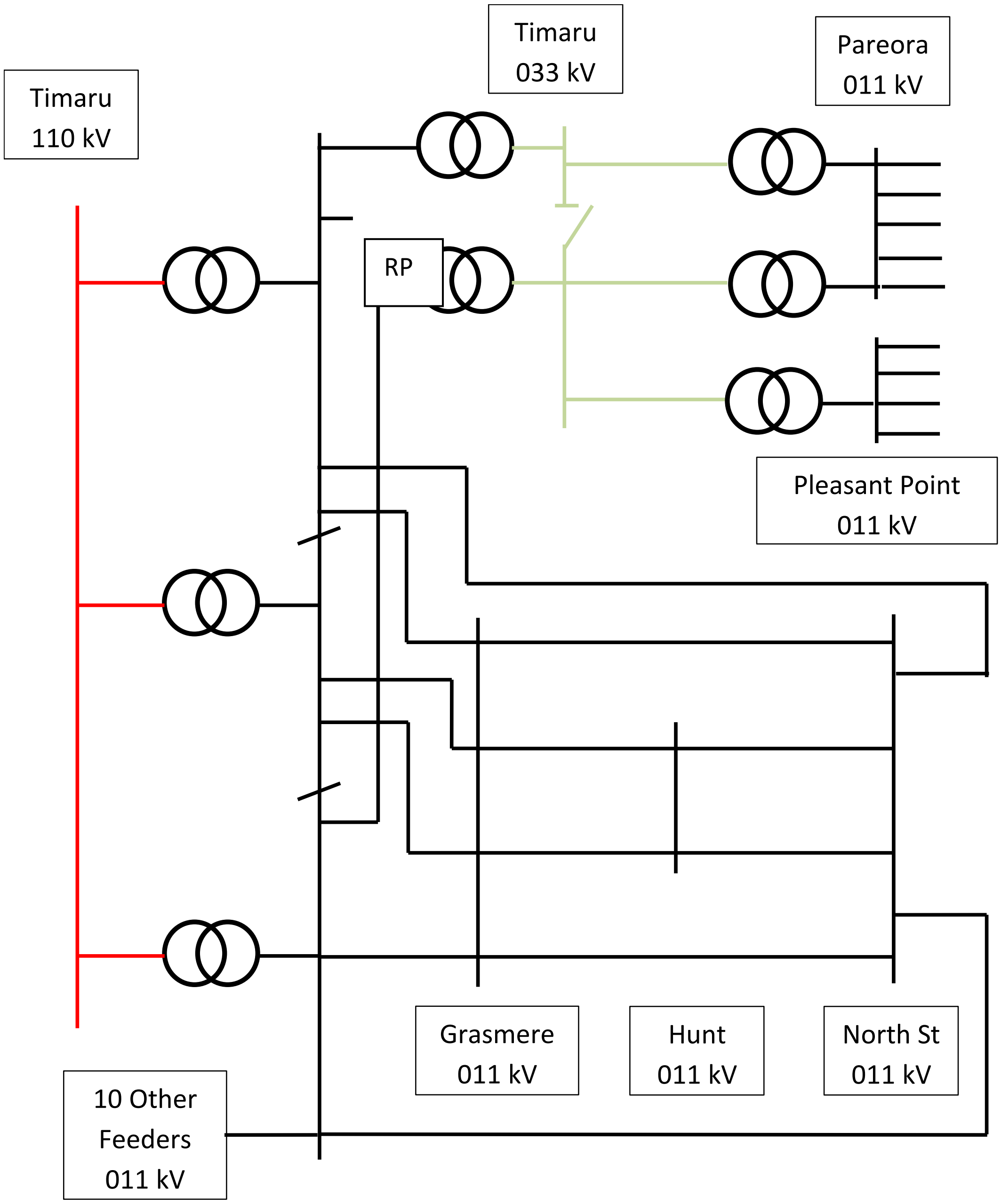


Table 9.110 Timaru Zone Substation key data

Transformer	Switchgear	Ripple Plant
2x 25 MVA OLTC 33/11 kV (2006) Excellent	3x 33 kV Reclosers (1986) Fair	1x Zellweger 317 Hz

Table 9.111 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.111 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Timaru	TIM 33 kV step up zone substation	N-0.7	N-0.75	Two step up transformers that feed a split 33 kV bus arrangement. PAR on each side of bus and have full redundancy available to the lines. PLP is fed off one bus, short duration loss can occur for a loss to that 33 kV bus until a tie is made to the remaining 33 kV bus.
Timaru	Timaru Residential	N-1	N-1	One additional feeder to TIM area was gained with TP changing their board. Lead out cables to first tee points were increased in size where possible.
Timaru	Timaru Rural	N-0.5	N-0.5	Limited fault back up from adjacent feeders from TIM and then as second resort PAR, PLP and TMK. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.
Timaru	Washdyke/ Seadown	N-1	N-1	Capacity is only sufficient for N-1, as new substantial loads are established investment in new sub-transmission feeders to SDW will be required. Install 33 kV cables from SDW to TIM to run at 11 kV.

The estimated demand listed in Table 9.112 over page, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.137 at page 313.

Table 9.112 Estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
62.2	0.7% (winter)	75.7 (winter)	0.7% historic some steps expected to come: residential growth heat pump uptake industry growth (Washdyke).

The capacity constraints on AELs network in the Timaru area network are shown in Table 9.113 below.

Table 9.113 AEL Network constraints

Constraint	Description	Intended remedy
Highfield (TIM2952) feeder loading	Heavily loaded feeder	Long term establish West End zone substation off 33 kV TIM GXP (timing uncertain).
Morgans Rd feeder (TIM2702) loading	Heavily loaded feeder	Long term establish West End substation off 33 kV TIM GXP (timing uncertain).
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).

TIM connects via fibre to WDK then via fibre to NST with a radio link over MEC to WDK in back up, detailed in Table 9.114 below.

Table 9.114 TIM Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	None	NST-MEC MEC-WDK (back up to fibre link break)	FO to WDK and back thru GRM/HNT to NST

There is a small amount of traffic on the Cu twisted pair cable TIM-WDK, mainly collects information from the three 33 kV reclosers.

Table 9.115 over page, details the SCADA system. Main system is three SEL 3530 to connect to IEDs. Abbey RTU to control Ripple Plant. Small amount of data from TP data bridge, mainly for ripple plant control off RevM.

Table 9.115 TIM SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, voltage and CB status at TIM. Security at TIM.	TIM 11 kV CB Control, though presently done thru TP. No remote control of 33 kV reclosers TIM Ripple on Abbey RTU to WDK via landline	CB control	Load data at TIM

9.7.3.1 Timaru-Grasmere St and Hunt St and North St Sub-transmission

The CBD sub-transmission key data shown in Table 9.116 below, details the Timaru CBD sub-transmission with respect to rating, age, and general condition.

Table 9.116 TIM-CBD Sub-transmission critical data

Line	Make up
Grasmere-Timaru	4x 11 kV 400 mm^2 Cu PILC Cables (1983) Fair
Grasmere-Hunt St and Grasmere-North St and Hunt St –North St (11 MW)	4x 11 kV 193 mm^2 Cu PILC Cables (1962) Fair
North St-TIM (11 MW)	2x 33 kV 1200 mm^2 Al XLPE Cables (2011) Excellent

9.7.3.2 Grasmere (GRM) and Hunt St (HNT) and North St (NST) Zone Switching Station detail

Grasmere, Hunt St and North St are switching stations which mean the stations perform important switching, protection, and SCADA operations but do not transform voltages as for zone substations. Whilst NST is presently a switching station there is space to fit 33/11 kV transformers when the sub-transmission is livened at 33 kV categorising NST as a Zone Substation. (Please note that these three “switching stations” are treated as “zone substations” as far as operating and maintenance are concerned).

The key data shown in Table 9.117 over page, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.117 Grasmere St, Hunt St, and North St Switching Station key data

Station	Transformer	Switchgear
Grasmere St (13 MW)		20x VCBs (2012) Excellent
Hunt St (11 MW)		16x VCBs (1984) Good
North St (11 MW)		20x VCBs (2011) Excellent

Table 9.118 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.118 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Timaru	Timaru CBD (GRM, HNT, and NST)	N-1	N-1	None
Timaru	Redruth	N-1	N-1	None
Timaru	Port	N-1	N-1	None

The estimated demand listed in Table 9.119 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed Table 9.137 at page 313.

Table 9.119 Timaru CBD estimated demand at zone substation level

2014 MW	10-year Rate and nature of growth	2023 MW	Provision for growth
39 MW (winter)	0.7% historic on TIM	45 (MW) (winter)	None required for local assets-substation and sub-trans capacity available. Additional CB's 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.

Table 9.120 below, shows the capacity constraints on AELs network in the Timaru area.

Table 9.120 AEL Network constraints

Constraint	Description	Intended remedy
Timaru sub-transmission to CBD	Heavy cable loadings	Establish city 33/11 zone substation off 33 kV TIM GXP (timing uncertain).

GRM/HNT/NST connects via fibre to WDK then via fibre to NST with a radio link over MEC to WDK in back up.

NST is serviced with Chorus telephone and fax. A broadband connexion is available over Chorus' services, which is detailed in Table 9.121 below.

Table 9.121 GRM/HNT/NST Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	None	NST-MEC MEC-WDK (back up to fibre link break)	FO to WDK via a ring NST-WDK and NST-HNT-GRM-TIM-WDK

There is a small amount of traffic on the Cu twisted pair cable HNT and VIC-WDK, mainly collects information from the HNT 11 kV feeders and VIC building alarms.

Each of GRM/HNT/NST has two SEL 3530 to connect to IEDs.

HNT remote control of feeder CBs is over the Cu twisted pair cable. HNT sub-transmission is on fibre/3035 is detailed in Table 9.122 below.

Table 9.122 GRM/HNT/NST SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, voltage and CB status. Security.	CB control	CB control	Load data

9.7.3.3 Pareora–Timaru Sub–transmission

The zone substation key data shown in Table 9.123 below, details the Pareora–Timaru sub–transmission with respect to rating, age, and general condition.

Table 9.123 PAR-TIM Sub-transmission critical data

Line	Make up	Limit at 6% Volt Drop (MVA)	Limit of Conductor at 50°C (MVA)	Limit of Cable	Lowest Limit
PAR-TIM 1	Mink/Petrel/Rango Cable 1/95/37/0.016	6.8	10.3 11.4	11.5	6.8
PAR-TIM 1 (Rebuild underway)	Iodine/Petrel Cable 1/95	10.3	16.6 11.5	11.5	10.0
PAR-TIM 2	Quail/ Cable 1/95/19/0.014	6.91	10.3	11.5	6.91
PAR-TIM 2 (Rebuild Underway)	Iodine/ Cable 1/95	10.09	16.6	11.5	10.09

9.7.3.4 Pareora (PAR) Zone Substation detail

The zone substation key data shown in Table 9.124 over page, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.124 Pareora Zone Substation key data

Substation	Transformer	Switchgear
Pareora (7 MW)	2x 9/15 MVA OLTC 33/11 kV (2011) Excellent	6x 33 kV VCBs SF_6 isophases (2011) Excellent 9x 11 kV VCBs(2008) Excellent

Table 9.125 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.125 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Pareora via 11/33 kV step up zone substation at TIM	N-1 on first 9/15 MVA (transformer limit), 7 MVA Sub-transmission limit to 6% voltage drop N on the remainder that cannot be transferred.	N-1	N-1 security for all periods. Some load can be transferred to STU and TIM in an emergency.	Pareora via 11/33 kV step up zone substation at TIM.

The estimated demand listed in Table 9.126 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.137 at page 313.

Table 9.126 PAR Estimated demand at zone substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
7.81 (summer)	3.2% per year expected as TMK until SAW then 2% Residential load dairy and irrigation development.	9 (summer)	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 St. Andrews GXP as it eventuates.

Table 9.127 below, shows the capacity constraints on AEL's network in the Pareora zone substation area network.

Table 9.127 AEL Network constraints

Constraint	Description	Intended remedy
Pareora 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. Rebuild sub-trans in iodine currently underway but will take four years (requires new pole positions). Rebuild No 2 first as more aged. Establish new St. Andrews GXP for partial load transfer (2018-19).

Pareora's Communications is detailed in Table 9.128 below.

Table 9.128 PAR Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	None	PAR-MEC MEC-WDK	None

Pareora has an SEL 3032 to connect to IEDs. SCADA detailed in Table 9.129 below.

Table 9.129 PAR SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, Voltage and CB status. Security.	CB control and transformer control	CB control	Load data

9.7.3.5 Pleasant Point-Timaru Sub-transmission

The zone substation key data shown in Table 9.130 below, details the Pleasant Point-Timaru sub-transmission with respect to rating, age, and general condition.

Table 9.130 PLP-TIM Sub-transmission critical data

Line	Make up	Limit at 6% Volt Drop (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable	Lowest Limit
PLP-TIM	Quail/Dog/Weke/ 19/0.014 Cable 1/95	8.7	10.3 12.6 16.6	11.5	8.7

9.7.3.6 Pleasant Point (PLP) Zone Substation detail

The zone substation key data shown in Table 9.131 over page, details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.131 Pleasant Point Zone Substation key data

Substation	Transformer	Switchgear
Pleasant Point (4 MW)	1x 5/6.25 MVA OLTC 33/11 kV (1980) Good	1x 33 kV Recloser (1980) Good 5x 11 kV VCB (2006) Excellent

Table 9.132 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.132 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Timaru	Pleasant Point via 11/33 kV step up zone substation at TIM	N-0.5 N on the remainder that cannot be transferred.	N-1	Majority of load increase likely in Totara Valley area. The 11 kV feeders from PLP to Totara Valley are too long to support major growth in irrigation. Consider investment of Totara Valley sub. Totara Valley substation could halve the Pleasant Point substation load. Some load can be transferred from PLP to ABY, TMK and TIM in an emergency. Encourage customers to be self-sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table 9.133 below, shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.137 page 313 below.

Table 9.133 Estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
3.62 (summer)	4.62% per year expected as TMK Residential load Dairy and irrigation development	5.69 (summer)	Existing transformer rated for the period. Some security via 11 kV back up from ABY, TIM and TMK. Possible sub built nearer irrigation load at Totara Valley to improve security.

Table 9.134 over page, shows the capacity constraints on AELs network in the Pleasant Point area network.

Table 9.134 AEL Network constraints

Constraint	Description	Intended remedy
Pleasant Point 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.	Larger transformer, or second or new substation at Totara Valley for load transfer (timing uncertain).

Pleasant Point's communications detailed in Table 9.135 below.

Table 9.135 PLP Communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	None	PLP-BRC BRC-MEC MEC-WDK	None

Pleasant Point has an SEL 3032 to connect to IEDs. SCADA detailed in Table 9.136 below.

Table 9.136 PLP SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, voltage and CB status. security.	CB Control	CB control	Load data

9.7.4 Development of GXP and Substations

Table 9.137 below, shows the growth trend to the year 2022.

Table 9.137 TIM 110 kV bus load growth

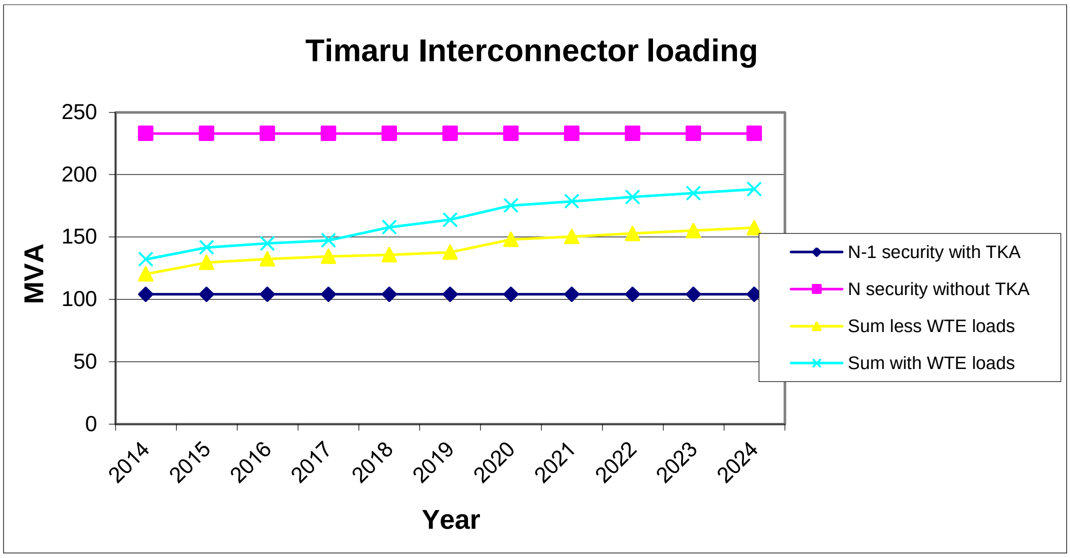
GXP Substation (Season Peak)	Growth Trend (Total MW MD)										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Timaru 110 kV (Summer)	120.4	129.5	132.5	134.5	135.8	137.8	148.0	150.4	152.8	155.2	157.6

Figure 9.22 over page, shows The Timaru 110 kV bus Growth Trend and security level and capacity.

An initial Solution Study Report (SSR) was undertaken by Transpower which promoted a 220/33 kV GXP to extend the useful life of the T5 and T8 220/110 kV interconnectors. With AEL delaying the introduction of the 33 kV GXP, the interconnectors will require further examination by Transpower.

These interconnectors supply the growing loads of Albury, Tekapo A, Temuka and Timaru. On occasion additional load is required to be supplied south to Bell's Pond, Studholme and Oamaru. During the dairy season Studholme is tied through. A tripping of the Waitaki feed

Figure 9.22 Timaru 110 kV bus load growth and supply security



into Studholme could lead to the interconnectors combined load being taken beyond their 120 MVA individual rating.

In the Temuka commentary options to off load T5 and T8 are given.

AEL has had recent discussions with Transpower for load to be limited through the T5 and T8 interconnectors during some maintenance periods on Tekapo A generation. This is an uncomfortable position, five to 10 MVA may not be able to be supplied. It seems the delays in having a solution for T5 and T8 will impact on South Canterbury. Other years may be dry with Tekapo A constrained, or Tekapo A released or maintenance, the probability of a repeat of the situation is high.

Table 9.138 below, shows the growth trend by year for Timaru.

Table 9.138 TIM Substation load growth

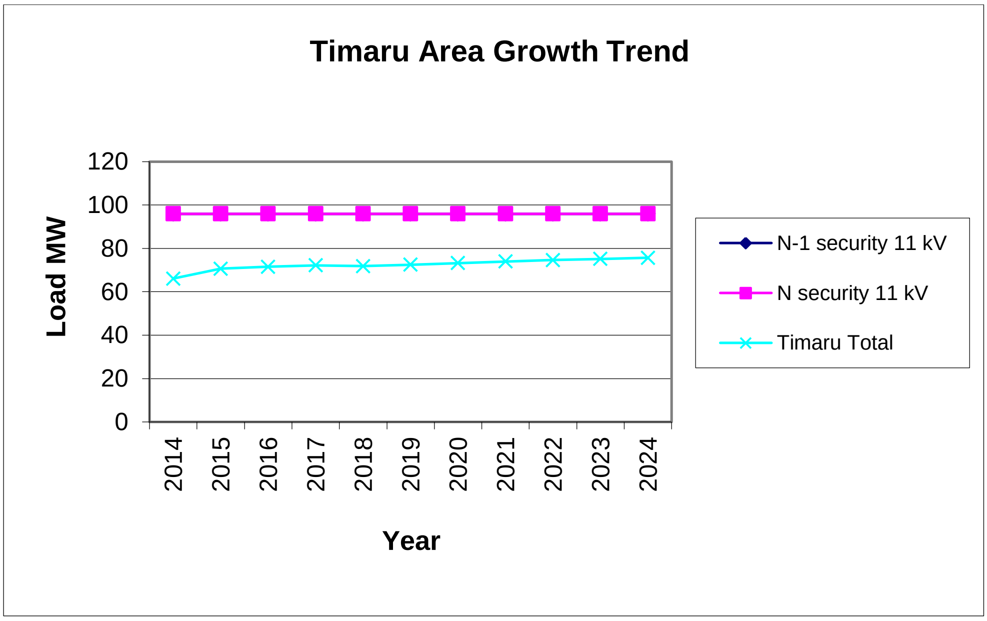
GXP Substation (Season Peak)	Growth Trend (Total MW MD)										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Timaru 11 kV (Winter)	62.6	63.1	63.5	64.0	64.4	64.9	65.3	65.8	66.2	66.7	

Figure 9.23 over page, shows The Timaru Area Growth Trend and security level and capacity.

Transpower, over the summer of 2013/14, will install three new supply transformers to run of two of three with the third on hot standby. The Timaru 11 kV GXP will then have plenty of capacity for the planning period with the known developments.

The 11 kV switch board was replaced in early 2012. The new board has been arranged to suit AELs needs for capacity and additional CBs to allow the new 33 kV rated sub transmission cables for the CBD to be connected and run at 11 kV for a period of some years

Figure 9.23 Timaru Area load growth and supply security



until a significant load growth is realised to justify the introduction of a 33 kV GXP.

9.7.4.1 Substation Growth Trend and Supply Security

Timaru is currently beyond firm capacity, this results in a reduction in N-1 security for certain periods of the week day load cycle. Transpower are in the process of replacing the three 110/11 kV supply transformers that are now unable to provide N-1 security at Timaru. This will probably be a two year process, after this N-1 security is returned to Timaru for all load periods.

The Timaru 110 kV bus capacity is watched as it can run beyond firm capacity for the normal supply of Albury, Tekapo, Temuka and Timaru. On occasion supply to Bell's Pond, Oamaru and Studholme could be expected from this bus as well. With the interconnecting 220/110 kV transformers at capacity on going load growth will result in a reduction in N-1 security for certain periods.

9.7.4.2 Rate and Nature of GXP Growth and Provisions made

Table 9.139 below, summarises the characteristic of the growth and summarises the plans to meet the energy requirements of the growth.

Table 9.139 Growth and response

GXP	Rate and nature of growth	Provisions for growth
Timaru	High – industrial/commercial	GXP investment

9.7.4.3 Specific Developments

Timaru CBD and Residential Areas

The Timaru CBD supply is under watch, AEL has postponed the introduction of a 33 kV GXP as a large load that was expected did not eventuate, some other smaller projects are delayed.

In the meantime AEL has strengthened its sub-transmission to the CBD, this was done with the use of 33 kV cables to the new North Street zone substation, but they are being operated at 11 kV.

Timaru – Hunt Street

Hunt St was built in 1984 and is in good condition, VCBs are fitted and most of the control equipment is electronic static type equipment. This type of board has a nominal 40 year life, replacement should be considered in 2024. The protection and control equipment is at the end of life being more than 20 years old. The sub-transmission protection and controls were replaced in 2011.

All the feeder protection is at end of life, this is planned to be replaced in 2014/15 with the SEL 751A + 55IC back up.

9.7.4.4 Timaru 11/33 kV Step up Substation

Limitations within the equipment in the AEL Timaru Step-up Substation (involving the existing 33 kV switchgear, NETs, and protection) were originally expected to be eliminated with the proposed new 33 kV GXP at Timaru. As this proposed 33 kV GXP has been delayed indefinitely (see elsewhere in this AMP) it is now necessary to upgrade the existing Timaru 11/33 kV step-up substation to provide adequate protection and control for the Timaru 19/25 MVA 11/33 kV step-up transformers and the three 33 kV sub-transmission lines (PAR-TIM 1, PAR-TIM 2, and PLP-TIM).

The downstream Pareora (PAR) and Pleasant Point (PLP) 33/11 kV Substations are basically suitable for the immediate future.

Further studies on this AEL Timaru 11/33 kV Step-up Substation are required.

PAR-TIM 33 kV Sub-transmission lines No.1 and No.2 upgrade

In 2010, load flows indicate that the existing 33 kV Pareora-Timaru line conductors were capable of delivering 6.8 and 6.9 MVA respectively for line 1 and 2 with a 6% voltage regulation, beyond this there was a marked drop in voltage leading to voltage collapse. The line should only be operated just under to 7 MVA. A five year reconductoring exercise is being undertaken to increase the line rating to beyond 10 MVA. Re-conductoring the 33 kV lines (presently Quail/Mink) with Iodine will lift the line ratings to 10.7 and 10.1 MVA respectively. Line rebuild is difficult as much of the line route is over private land, easements etc. would have to be gained, new pole positions taken (requires re-poling with shorter spans).

9.7.4.5 Issues Arising from Estimated Demand

In December 2013 Transpower raised capacity constraints on Timaru's T5 and T8 main 220/110 kV interconnecting transformers, identified during studies for the Tekapo A generator release for canal repairs, AEL have been asked to be able to shed load for contingent events.

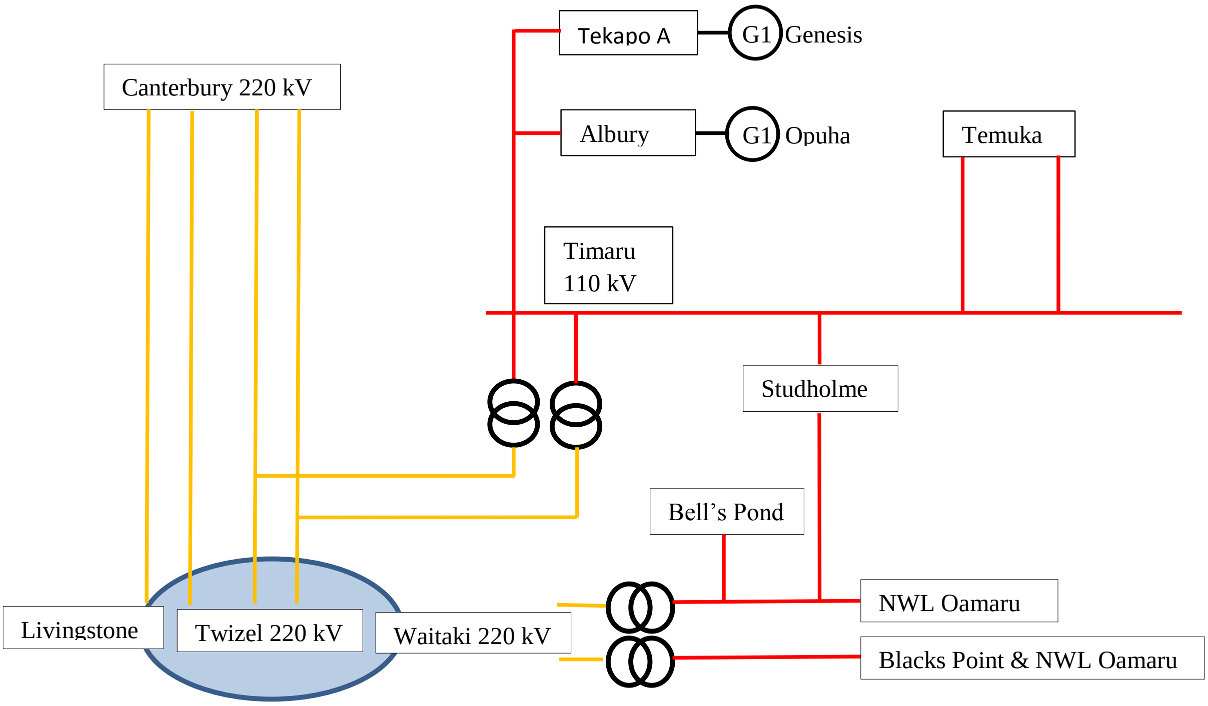
AEL is not seeing a lot of activity from Transpower in addressing the above issues, load is already being asked to be shed, AEL would like to avoid new loads being turned away.

9.8 Twizel Grid Exit Point

9.8.1 Introduction

Figure 9.24 below, shows how Twizel GXP (TWZ) is configured with our network and Transpower's transmission network. Twizel GXP is supplied by 220 kV Twizel GXP.

Figure 9.24 GXP configuration



9.8.2 GXP Description

Similar to Tekapo, Twizel is supplied from a single source Transpower 33 kV CB feeder onto a short AEL overhead line into its Twizel zone substation. AEL has an indoor 11 kV switchboard with two feeders supplying Twizel township and two additional feeders supplying the surrounding rural area. Subdivision development is very popular, but AEL have not seen a lot of actual load growth from these, as well as potential for irrigation scheme development. An embedded network operator is active in also providing supply to new developments in this area at two Network Supply Points at Manuka Terrace and Mackenzie Park.

9.8.2.1 Critical data:

The critical GXP data shown in Table 9.140 over page summarises the key physical attributes of the station, the voltages, the capacity, the security, and the power flow. AEL shares the capacity at TWZ with Genesis, Meridian and NWL.

Table 9.140 Studholme Substation key data

GXP	GXP Transmission Potential	GXP Point Of Supply Potential	Capacity	N-1 Capacity	AEL Demand Dec '13
Twizel	220 kV	33 kV	40 MVA*	20 MVA*	2.9 MW

Table 9.141 below, shows the capacity constraints in the Twizel GXP.

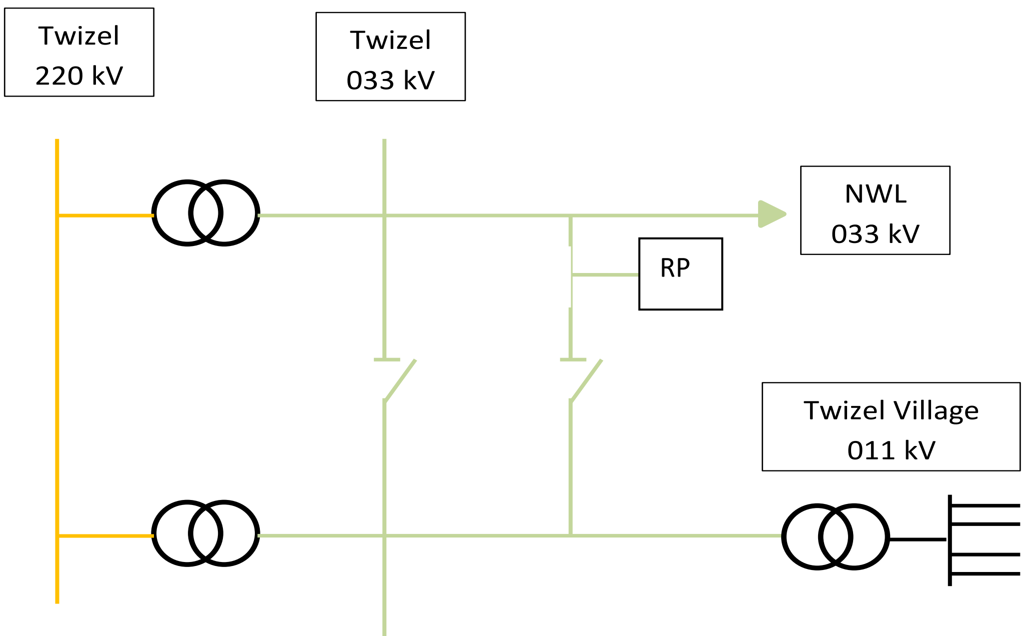
Table 9.141 GXP Network constraints

Constraint	Description	Intended remedy
None		

9.8.3 Twizel GXP Network information

Figure 9.25 below, shows the Timaru GXP area network.

Figure 9.25 Twizel GXP area network



9.8.3.1 TWZ-TVS Sub-transmission

Table 9.142 below, details the Twizel to Twizel Village sub-transmission (TVS) with respect to rating, age, and general condition.

Table 9.142 TWZ-TVS Sub-transmission critical data

Line	Make up	Limit at 6% PD (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable (MVA)	Lowest Limit	Notes
TVS-TWZ	Dog	82.48	12.6		12.6	

9.8.3.2 Twizel Village (TVS) Zone Substation detail

Twizel is a service town that is also popular as a holiday and tourism centre, being the nearest town to Mt Cook.

At present there is a peak demand of 2.9 MVA on a 5/6.25 MVA OLTC transformer, 1951 vintage 11 kV BTH switchgear (predominantly with Metro Vickers protection relays). The site was handed over from the Ministry of Works toward the end of the Hydro project. All of AEL's monitoring of the 11 kV switchgear shows it is still in serviceable condition, some minor replacements of protection equipment is likely to occur.

AEL has observed the load growth, evident before the 2009 recession, wane. AEL will watch the load for signs for growth resurgence before committing to any development plans for the substation.

With a developer interested in the land the Twizel Village Zone Substation is situated on, AEL agreed to plan conceptual redevelopment for 2014/15 with earliest possible construction in 2016. However there are long standing issues with soil resistivity, moving from this site with meshed earth mat to the village ring and possibly to Transpower's main substation will present significant challenges.

AEL note the recent establishment of a major salmon processing plant in Washdyke instead of at Twizel.

Proposals of irrigation have been presented for the area, few on the Twizel side of the Waitaki River have proceeded, some to the south in Network Waitaki's area have been developed.

If irrigation prospects proceed, a mix of 11 kV and 33 kV supply options are available:

- Possible Pukaki Outlet 33/11 kV zone substation (estimated for 2016/17).
- Possible supply past Ohau C power station to Haldon.

Discussions with Transpower have been held to gain an additional 33 kV feeder.

Table 9.143 below details the major assets with respect to rating, age, and general condition. The maximum demand at the various substations is also provided.

Table 9.143 Twizel Zone Substation key data

Transformer	Switchgear	Ripple Plant
1x 5/6.25 MVA T1 OLTC (1972) Good 1x 3 MVA (1964) Fair (off line spare)	1x 33 kV OCB (1960) Poor 8x 11 kV OCBs (1951) Fair	438 Hz Landis and Gyr (Shared with NWL, but AEL have no effective access)

Table 9.144 below, lists the existing level of security at the substation and justifies any shortfall.

Table 9.144 Security level

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Twizel	Twizel CBD	N-0.5	N-0.5	No alternate supply to station. Limited 11 kV rings. Encourage customers to be self–sufficient for their essentials. As for CD emergencies.
Twizel	Twizel Rural	N	N	Limited fault backup Encourage customers to be self–sufficient for their essentials. As for CD emergencies.

The estimated demand listed in Table 9.145 below shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 9.149 over page.

Table 9.145 TVS estimated demand at Zone Substation level

2014 MW	10-year Rate and nature of growth	2024 MW	Provision for growth
2.8 (shoulder)	2.21% historic on TWZ Residential load Large scale subdivision Dairy and Irrigation development	3.6 (shoulder)	Possibly rebuild substation in conjunction with developer to free land. Extend 33 kV line to new irrigation development and install smaller dedicated substations.

Table 9.146 below, shows if there are any capacity constraints on AEL's network in the Twizel Village Sub area network.

Table 9.146 AEL Network constraints

Constraint	Description	Intended remedy
None		

TVS connects via radio systems detailed in Table 9.147 below.

Table 9.147 communications summary

VHF	UHF Analogue	UHF Digital	Fibre Optic
VHF for voice traffic	TVS-MRC MRC-WDK		None

Mt Rollesby (MRC) is not AEL's site, AEL rent space.

A radio was being established TVS-TWZ for ripple plant control, the project waned when the ripple plant was found to be unsuitable for both NWL and AEL use.

SCADA consists of L&N C68 RTU equipment. Detailed in Table 9.148 over page.

Table 9.148 TVS SCADA summary

Supervision	Control	Automation	Data Acquisition
Current, Voltage and CB status at TVS. Security at TVS	TVS CB Control. TVS pilot wire control.	Auto Reclosing CB	Load data at TVS

9.8.4 Development of GXP and Substations

Table 9.149 below shows the growth trend to the year 2022.

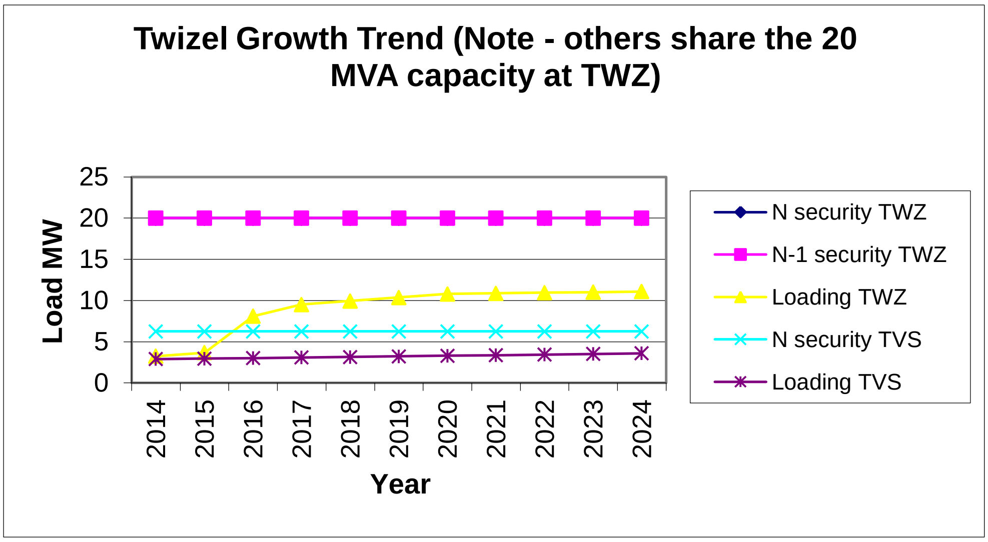
Table 9.149 Substation load growth

GXP Substation (Season Peak)	Growth Trend (Total MW MD)										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Twizel 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	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4	3.4	3.5	3.6
Irrigation on 33 kV	0.4	0.7	5.1	6.4	6.8	7.1	7.5	7.5	7.5	7.5	7.5

Note: The 20 MVA firm capacity is shared with Meridian Energy and Network Waitaki.

Figure 9.26 below, shows The Twizel Area Growth Trend and security level and capacity.

Figure 9.26 Twizel Area load growth and supply security



The load growth in Twizel in the tourism sector has stagnated with a slight reduction in peak demand. The highest loads occur on the autumn and spring holiday weekends, the load can be dependent on the weather at the time.

There have been a couple of enquiries for irrigation but AEL is uncertain about their prospect of being established and as a result they have been pushed back to 2016.

Indications so far would point toward these being remote from the Twizel substation so would need a new zone substation established for them. The 11 kV distribution would be too light to carry the load being indicated. As well the prospects are not firm enough yet to know what will be done with the fodder grown.

An area of load growth is the expansion of salmon farming and processing. The farms are increasing in size and the next processing plant is being established in Washdyke.

Twizel's zone substation has a suitably rated transformer at 5/6.25 MVA transformer. The transformer is fitted with an on-load tap changer (OLTC) which is important as the TWZ 33 kV bus swings with differing generation patterns.

9.8.4.1 Substation Growth Trend and Supply Security

The Twizel supply is made via a single 33 kV line, some tying ability to a Network Waitaki 33 kV line is available, and vice versa, to give some security of supply from the Twizel 33 kV bus. The installed capacity is shared with two other companies, AEL does not know fully about the other companies intentions and assume the supply capacity is secure for the planning period.

9.8.4.2 Rate and Nature of GXP Growth and Provisions made

Table 9.150 below, describes the rate and nature of growth at the GXP level as well as provision for growth.

Table 9.150 Growth and response

GXP	Rate and nature of growth	Provisions for growth
Timaru	Med – rural and Subdivision	GXP investment

9.8.4.3 Specific Developments

Twizel GXP Development

Transpower's Twizel 33 kV GXP bus is run split and is fed via two 20 MVA OCTC 220/33 kV transformers. The 33 kV bus was originally split as the 33/11 kV construction transformers for the Hydro were not able to withstand the full fault level. Transpower suggests the split avoids incidences on the 33 kV bus causing instability on the 220 kV bus. There is no 33 kV bus coupler or bus bar protection so running the bus tied would be problematic during a fault.

AEL's supply is not as secure as a tied bus arrangement, but this has been of little concern as the outage rate is very low. If a transformer is lost or released Transpower can easily tie the two bus halves to the remaining transformer.

A sole 33 kV feeder is taken from the Twizel switching station to the Twizel Village zone substation on the edge of Twizel. Preliminary discussions have been held with Transpower regarding the option of taking a second feeder.

The taking of a second feeder is not straight forward as the Transpower split 33 kV bus will inhibit either:

i) the ability of AEL to run a solid bus should supply be taken from either side of the Transpower bus, or
ii) bus tying in the zone substation as AEL may end up with a slightly less secure supply if both feeders are connected to the same side of the bus.

Transpower is in agreement that if AEL fits suitable protection at the far end of the feeders with back feed protection then a tie would be allowed in AEL's zone substation.

More analysis is required to determine the best path forward for Twizel.

Prior to set off, a view on how quickly the loads may be growing will have to be established from both the residential and irrigation demands. Transpower has programmed to investigate moving the 33 kV outdoor switchgear indoors. At that time a second 33 kV feeder to Twizel Village substation would also be evaluated.

Any project at Twizel will be funded via a New Investment Contract with Transpower

Twizel Zone Sub Development

Please refer to Twizel Village (TVS) Zone Substation detail on page 320.

Ripple Plant Upgrade

A shared ripple plant has been established at Twizel with Network Waitaki Limited (NWL). Its frequency is akin to Network Waitaki's as they hold the larger population of ripple receivers. With the Twizel 33 kV bus being run split and Network Waitaki being on the "other side" AEL have not been able to use the plant, the plant does not have sufficient power to pass signal through T18 and T19. Future ripple plant development will in time allow time clocks at Twizel to be replaced with more reliable ripple relays and security for load control in the Waitaki area.

9.8.4.4 Issues Arising from Estimated Demand

AEL have an N security supply at Twizel with ability to tie to NWL's feeder or to provide a reciprocal connexion in case of their loss.

Transpower can also tie their 33 kV bus to connect AEL's feeder to the alternate GXP transformer.

AELs attempt to gain a second feeder from Transpower proved uneconomic so will be reviewed when Transpower replace the outdoor 33 kV switchgear with indoor

.

Appendix A Summary of 11 kV Feeders

Table A.1 below, 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	Albury	2732	Raincliff	86	2348	115	85.74	0.94
ABY0111	Albury	2742	Cave	226	4842	393	207.83	1.10
ABY0111	Fairlie	F309	Fairlie	332	11655	977	244.23	2.00
BPD1101	Bell's Pond	CB2	Ikawai	105	6,600	145	67.39	2.99
BPD1101	Bell's Pond	CB3	Waikakahi	81	3,440	104	53.66	1.14
BPD1101	Bell's Pond	CB4	Tawai	136	8,900	364	71.43	3.67
BPD1101	Bell's Pond	CB5	Ripple Plant	1	-	1	0.01	0.14
STU0111	Studholme	01	Otaio	189	15,398	311	114.33	4.62
STU0111	Studholme	02	Glenavy	33	2,373	42	19.43	1.68
STU0111	Studholme	03	Waimate	89	12,555	1,885	33.32	4.78
STU0111	Studholme	07	Waihaorunga	153	5,275	223	130.36	1.85
STU0111	Studholme	08	Mt Studholme	175	8,498	291	87.31	2.52
STU0111	Studholme	09	Morven	174	7,693	278	101.33	2.36
TIM0111	Grasmere	02	White Street	6	2,950	361	2.17	2.72
TIM0111	Grasmere	05	Nile Street	6	2,650	579	2.57	2.54
TIM0111	Grasmere	06	Parkview Terrace	3	1,950	9	3.39	1.75
TIM0111	Grasmere	07	Douglas Street	3	1,400	240	1.51	0.48
TIM0111	Grasmere	10	Ashbury Park	4	1,950	185	2.85	1.98
TIM0111	Grasmere	12	Selwyn Street	7	3,100	541	2.28	1.94
TIM0111	Grasmere	15	Park Lane	6	2,600	465	2.69	2.08
TIM0111	Grasmere	16	Evans St./North Mole	4	2,650	9	3.67	1.81
TIM0111	Grasmere	17	June Street	4	2,300	200	1.53	1.25
TIM0111	Grasmere	20	Hobbs Street	5	2,600	410	2.00	1.77
TIM0111	Hunt	01	Harper Street	2	1,000	232	1.22	0.84
TIM0111	Hunt	02	Wilson Street	5	1,900	323	2.36	1.01
TIM0111	Hunt	04	Baker Street	4	1,900	397	2.22	1.63
TIM0111	Hunt	05	Le Cren Street	8	4,550	577	2.33	2.29
TIM0111	Hunt	07	Church Street - South Side Footway	4	2,600	270	1.58	1.36
TIM0111	Hunt	10	Gibson Street	3	1,200	173	2.26	0.91
TIM0111	Hunt	11	Rhodes Street	6	2,350	587	2.60	1.44
TIM0111	Hunt	13	Clifton Terrace	4	1,900	485	1.53	1.40
TIM0111	Hunt	14	Church Street - South Side Roadway	3	2,150	61	1.93	1.53
TIM0111	Hunt	16	Arthur Street	5	3,400	198	1.36	1.38
TIM0111	North	03	Redruth 1					0.52
TIM0111	North	04	Rose St	4	2,050	346	1.88	1.03
TIM0111	North	05	Craigie Ave	8	3,500	694	3.55	2.29
TIM0111	North	08	Barnard St	5	2,500	159	1.08	1.49
TIM0111	North	09	Port 1	1	500	2	2.04	1.28
TIM0111	North	10	Fraser St	5	2,800	22	2.39	2.87
TIM0111	North	11	Hayes St	6	3,800	75	1.87	2.77
TIM0111	North	12	High St	10	3,325	237	5.27	1.36
TIM0111	North	13	Port 2	3	3,400	13	2.32	2.42

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD
TIM0111	North	16	Victoria St	5	2,400	331	1.68	1.45
TIM0111	North	17	Safford St	5	3,900	194	2.19	1.86
TIM0111	North	18	Redruth 2					1.42
TIM0111	Pareora	CB3	CFM No.1			1	0.34	2.48
TIM0111	Pareora	CB4	St. Andrews	213	9,060	376	128.55	1.92
TIM0111	Pareora	CB5	CFM No. 2			1	0.34	2.48
TIM0111	Pareora	CB6	Normanby	169	6,150	522	75.17	1.61
TIM0111	Pareora	CB7	Holmestation	163	4,114	282	116.29	1.40
TIM0111	Pleasant Point	01	Waitawa	123	10,168	243	42.83	1.61
TIM0111	Pleasant Point	02	Sutherlands	67	1,303	90	44.20	0.83
TIM0111	Pleasant Point	04	Totara Valley	150	7,870	527	75.22	2.11
TIM0111	Pleasant Point	05	Pleasant Point Township	33	2,825	305	16.54	1.20
TIM0111	Timaru	2682	Ripple Plant No.1				0.10	
TIM0111	Timaru	2692	North Street 1				5.95	9.21
TIM0111	Timaru	2702	Morgans Rd	21	5,360	834	8.44	2.50
TIM0111	Timaru	2712	Mountain View Rd	33	6,340	931	12.94	5.04
TIM0111	Timaru	2732	AEL T1	3		2	17.85	5.33
TIM0111	Timaru	2742	Seadown	283	17,648	774	97.76	4.56
TIM0111	Timaru	2762	AEL Yard	16	5,280	134	6.93	4.56
TIM0111	Timaru	2832	Grants Rd	22	5,650	1,117	7.82	2.72
TIM0111	Timaru	2852	Levels	396	9,615	820	158.80	2.68
TIM0111	Timaru	2862	Meadows Rd	16	9,425	75	6.72	5.32
TIM0111	Timaru	2922	AEL T2	1			31.48	8.42
TIM0111	Timaru	2942	Old North Rd	15	7,300	37	4.52	3.41
TIM0111	Timaru	2952	Highfield	75	13,638	1,369	29.20	4.25
TIM0111	Timaru	2972	Smithfield	12	2,760	293	5.89	4.40
TIM0111	Timaru	2992	Ripple Plant No.2	1	-	3	0.15	0.47
TKA0331	Balmoral	M216	Simons Pass	15	340	26	36.69	0.30
TKA0331	Glentanner	M210	Glentanner	6	410	12	9.09	1.20
TKA0331	Haldon-Lilybank	M38	Lilybank 22 kV	8	315	12	38.03	0.30
TKA0331	Haldon-Lilybank	M40	Haldon Station 22 kV	30	760	37	77.95	0.70
TKA0331	Tekapo	M200	Haldon-Lilybank	10	1,875	68	5.66	0.96
TKA0331	Tekapo	M201	Balmoral	7	1,775	6	6.02	0.32
TKA0331	Tekapo	M205	Godley	9	525	66	20.73	0.11
TKA0331	Tekapo	M206	Tekapo Township	21	3,965	282	8.39	2.29
TKA0331	Tekapo	M207	Local Service	1	3,050	2	0.06	0.30
TKA0331	Unwin Hut	M158	Village	5	2,300	14	5.27	1.00
TKA0331	Unwin Hut	M159	Village	6	815	69	4.95	0.50
TMK0331	Clandeboye Sub 1	T600	Tie to Milk Powder 2				0.50	
TMK0331	Clandeboye Sub 1	T601	Fire Services	10	8,300		0.44	4.21

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD
TMK0331	Clandeboye Sub 1	T602	Whey Processing	6	6,500		0.15	3.57
TMK0331	Clandeboye Sub 1	T603	Lactose Plant	1	1,000		0.09	0.19
TMK0331	Clandeboye Sub 1	T604	Spare				0.02	1.71
TMK0331	Clandeboye Sub 1	T605	Tie to Milford Clandeboye rd.					
TMK0331	Clandeboye Sub 1	T609	Milk Reception	3	2,500		0.47	0.58
TMK0331	Clandeboye Sub 1	T610	Chilled Water No. 1	4	6,000		0.55	2.85
TMK0331	Clandeboye Sub 1	T611	Effluent Plant	5	6,000		0.49	1.98
TMK0331	Clandeboye Sub 1	T612	Milk Treatment	2	4,000		0.55	1.20
TMK0331	Clandeboye Sub 1	T613	Rolleston Road	87	8,190	230	48.56	3.39
TMK0331	Clandeboye Sub 1	T614	Tie to Power Handling	1	1,500		0.53	1.22
TMK0331	Clandeboye Sub 2	T650	Tie to Milk Powder 1				0.18	5.21
TMK0331	Clandeboye Sub 2	T651	Milk Powder 3	7	19,000		0.25	6.15
TMK0331	Clandeboye Sub 2	T652	Tie to WPC	1	1,500		0.41	2.33
TMK0331	Clandeboye Sub 2	T653	Chilled Water 3	4	3,200		0.32	1.19
TMK0331	Clandeboye Sub 2	T654	Tie to Boilerhouse	4	6,000		1.02	2.63
TMK0331	Clandeboye Sub 2	T658	Milk Powder 2	6	16,000		0.17	3.50
TMK0331	Clandeboye Sub 2	T659	Tie to Energy Centre 1				0.60	
TMK0331	Clandeboye Sub 2	T660	Refrigeration	4	5,000		0.53	1.98
TMK0331	Clandeboye Sub 2	T661	Laboratory	3	4,500		0.36	1.47
TMK0331	Geraldine	01	Speechly	222	7,083	400	126.85	1.00
TMK0331	Geraldine	02	Geraldine Township	77	9,595	1,346	25.79	2.50
TMK0331	Geraldine	03	Woodbury	291	7,900	668	149.00	1.50
TMK0331	Rangitata	02	Arundel					1.41
TMK0331	Rangitata	03	Mahan Road	21	1645	19	30.00	2.92
TMK0331	Rangitata	04	Main South Road	55	5623	76	31.85	1.79
TMK0331	Rangitata	11	Belfield	62	4515	83	34.68	2.53
TMK0331	Rangitata	12	Orton	13	1170	14	11.80	1.16
TMK0331	Rangitata	13	Rangitata Island					2.49
TMK0331	Temuka	01	Temuka West	9	51,675	412	5.16	2.17
TMK0331	Temuka	02	Milford	123	7,245	266	56.20	2.42
TMK0331	Temuka	03	Winchester	211	10,163	562	77.42	3.20
TMK0331	Temuka	07	Rangitata	90	7,080	172	35.36	3.18
TMK0331	Temuka	08	Temuka East	71	13,105	1,771	22.91	5.74

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD
TMK0331	Temuka	09	Waitohi	175	55,576	279	107.27	1.55
TWZ0331	Twizel	Z1	Urban No. 1	22	4,230	610	6.99	1.24
TWZ0331	Twizel	Z2	Urban No. 2	29	5,370	643	11.85	1.32
TWZ0331	Twizel	Z3	Industrial	1	50	1	0.21	0.00
TWZ0331	Twizel	Z4	Twizel Rural	42	2,260	96	37.39	0.37
TWZ0331	Twizel	Z9	Local Service	1	3,030	2	0.01	0.00
Total		**131**		**5,518**	**602,063**	**30,484**	**3,219**	**262**

Appendix B Capex 12 Month Worksplan for 2014/15

Table B.2 below provides a list of projects that we will either: complete during 2014/15; or start and complete during 2014/15.

Projects are listed in real (constant) dollars and in thousands ($000).

The projects are categorised according to the relevant AMP Expenditure Category as shown in Table B.1 below:

Table B.1 Project categories

Project category	Description
A	Overhead Lines, new, refurbished & upgraded
B	Customer Connections, including new subdivisions and extensions for new services
C	Metering & Relays
D	Distribution Substations, including transformer, regulators, ring main units, etc.
E	Underground Cables, including overhead to underground conversions
F	Zone Substations, including load control plants
G	Unspecified
H	System Development

Table B.2 List of projects to be completed and/or started during 2014/15

Exp. Cat.	Works Programme Project	Budget ('$000)	Project Details
A	Various O/H new builds and upgrades	1,000	Cairns Rd Southburn replace 13GS conductor plan 1042 Relocate ABS outside RGA sub to next S/O down road to SH1. Waihurunga irrigation line re-builds and upgrades.
A	Te Moana Rd refurbishment	170	Motukaika Rd rebuild 1 km, 12 poles.
A	33 kV Softwood pole replacements Clayton Rd	120	Load growth in the area, especially at Barkers Fruits, and planned load growth is restricted by line capacity.
A	Simons Pass Fdr 22 kV to 11 kV	220	Along Clayton Rd, 25 poles @ $10k ea. 3 Year project to manage SAIDI's.
A	Ikawai / Tawai 11 kV	100	From Balmoral substation. Removes health and safety issues with current substation. 17 Tx;'s and removal of sub.
A	Waihao River crossing	40	2 km 11 kV Magpie to supply two ICP's same farmer.
A	Mt Harris 110 kV double circuit	30	
A	Morven regulator to Crowes Rd - Tawai Fdr rebuild	110	Budget to start concept design and surveying. Main budget expected to be spent when ODL applies for drier 3/4 supply.
A	Morven Fdr re-route at Leighbank	150	Replace 2.1 km conductor (Flounder) from Morven regulator to Crowes Rd.
A	Mackle Rd conductor upgrade	165	2.5 km Morven Glenavy Rd - rail xing
A	ABS replacements	110	Along Springfield Rd.
A	New ABS's	70	Replacement of known ABS which are failing and replacement with load breaks to improve network switching.
A	Sub-transmission lines reconductor to Iodine	470	This budget to replace existing links with ABS's @ $12k ea.
A	Motukaika Rd - Cave Fdr upgrade	75	Transformer purchases. Reduction due to consignment stock.
B	New Connections and Subdivisions	2,400	Pareora 33 kV 1 and 2 rebuild - Mink to Jaguar (2 x16 km). Current circuit capacity is 6.8 MVA and demand peaking at 8.1 MVA. Tx's upgraded to 9/15 MVA. Circuit upgrade will increase capacity to 10 MVA required to meet N-1 criterion. Some 2010/11 work not completed and budget carried forward.
D	Transformers distribution for subdivisions, extensions and replacements	440	
D	Voltage regulator and Capacitor Bank Installations	250	This budget item is related to loadgrowth. Due to the loads on our system and the connection of new loads we are experiencing voltage regulation issues which can

Exp. Cat.	Works Programme Project	Budget ('$000)	Project Details
			be addressed by the installation of voltage regulators OR shunt capacitors at various locations. Shunt capacitors does however influence our load control capability since the capacitors absorb the ripple signals which results in failure to operate loads via this means. Budget based on $60k per capacitor installation, and $120k per regulator installation. A second Tx at BPD will reclaim 4 regulators.
D	Distribution Sub refurbishment	220	
D	Two pole distribution sub refurbish.	170	Safety and reliability due to inadequate fault ratings, statter switch replacements due to condition and lack of maintenance, pole and structure condition assessment, seismic strength of installation. Difficult to assign a unit cost as well as quantity per annum.
D	Replacement RMU's	230	
D	New RMU's	230	Budget for 4 RMU's at $50k ea.
D	Reclosers New	200	Budgets are based on 6 sites per annum and $30k per site.
D	Reclosers Replacements	120	This is a project to replace old ball and chain types which freezes up in winter resulting in faulty operation. They are also filled with oil which results in maintenance concerns. Two remaining out at Tekapo for replacement namely M142 and M210. M142 will need to be replaced with two breakers, one each side of transformer. Cooper reclosers are also being changed out, retro fitted with SEL relays and re-deployed on the network.
D	Earthing	330	Results from earth testing program shows large number of sites outside of regulations. Budget based on 85 NB sites identified @ $2,500 per site.
E	Underground Cable Upgrades (G)	420	Project needs detailed planning. Many 11kV cables in CBD are at full capacity and needs upgrading. At estimated cost of $200/metre this allows for 2.5km per annum to be replaced. STAFFORD/BARNARD STREET!! HUNT RING - FREQUENT FAULTS IN THIS PART OF THE NETWORK.
E	Underground Cable Upgrades (R)	220	
E	O/H to U/G conversions	650	11 kV and 33 kV Overhead Lines in urban areas conversion to underground for Network reasons. These projects have been identified. There are however a number of instances where we have HV O/H lines going down the back residential properties. These need to be re-located to eliminate safety issues as well as improve maintenance access. Budgets can be delayed but should retain line item for when and if needed.

Exp. Cat.	Works Programme Project	Budget ('$000)	Project Details
F	Zone Substation Protection replacement	220	Replacement of old electromechanical or electronic relays that are at end of life, and upgrading of some existing protection.
F	Mobile sub site preparations	220	Prep. 3 sites per annum @ $65k ea.
F	33/22 kV CB and recloser replacement	100	Replacing old oil CB's with vacuum CB's ie Unwin Hut, Albury, Haldon, Fairlie, Twizel, Tekapo
F	Ripple Plant replacement and LS rework	160	Replace old rotary plant which is giving problems. Relays (in stock) must also be replaced.
F	Ripple Relay Changeout	220	As part of the ripple plant replacement all the ripple relays needs to be changed out as well. This budget is based on 1600 relays and $250 per unit to change out.
G	New Equipment	150	
G	QOS Investigations	50	Budget used to record QoS parameters.
H	33 kV Upgrade	2,000	This is a preliminary budget based on existing feeders and using the Portacom design at Pareora.
H	Comms and RTU	100	
H	11 kV protection/control replacement (17 CBs)	530	
H	Substation upgrade	450	Bruno to review EPR issues
H	Change-out oil CBs for LMVP	120	Check with RPS if they can re-work the Victoria St breakers for this purpose.
H	New transformer install	150	
H	New SCADA Master Station	100	Replacing existing old mater station.
H	Communications room upgrade	120	
H	SCADA and pole top equipment automation (eg reclosers)	220	Budget to establish communications network and automate pole mounted reclosers.
H		200	Replacement of all old locks with new Abloy locks.
H		250	
Total Capex 2014/15		**14,070**	

Appendix C Capex 10–Year Worksplan from 2014/15

This appendix lists the works projects for the next 10 years.

All identified projects for this AMP period were prioritised according to the following colour code and definitions. The AEL Board approved the budgets for the "High Priority" projects ONLY. Totals for the Medium Priority project budgets are shown for information only. Table C.1. below describes the projects priority, while Table C.2. lists project categories. Projects are listed in real (constant) dollars and in thousands ($,000.00).

Table C.1 Project Priority key

High priority - Must Do Projects
Medium priority - Need To Do - Conditional upon an external party initiating a project - budget could possibly be deferred.

Table C.2 Project catergories

Project category	Description
A	Overhead Lines, new, refurbished & upgraded
B	Customer Connections, including new subdivisions & extensions for new services
C	Metering & Relays
D	Distribution Substations, including transformer, regulators, ring main units, etc.
E	Underground Cables, including overhead to underground conversions
F	Zone Substations, including load control plants
G	Unspecified
H	System Development

Table C 3 CAPEX 10 year works plan

No	Project Cat.	ID Sch. 6a(i)	ID Sch. 6a(i)2	ID Sch. 6a(ii)	ID Sch. 6a(iii)	ID Sch. 6a(iv)	GXP/Zone/Substati	Priority	AEL Works Programme Projects	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	TOTAL	Project Details	NCL Distribution	NCL Technical	At Risk
1	A	Refurbishment & Renewal				Distribution and LV lines	Network	High	Various O/H new builds & upgrades		921	1000	1600	2400	2400	2400	2400	2400	2400	2400	2400	**21,800**	Cairns Rd Southburn replace 13GS conductor plan 1042 Relocate ABS outside RGA sub to next S/O down road to SH1. Waihurunga irrigation line re-builds & upgrades.	1000		500
50	A	Growth				Subtransmission	ABY	Medium	Totara Valley 33 kV Fdr				2500									**2,500**	Dependant on load growth and establishment of zone substation. 20 km 33 kV line build.			
3	A	Growth				Distribution and LV lines	GLD	High	Te Moana Rd refurbishment			170										**170**	Motukaika Rd rebuild 1 km, 12 poles.	156.4		
4	A	Reliability, Safety & Environment	Quality of Supply			Subtransmission	FLE	High	33 kV Softwood pole replacements Clayton Rd			120	100	100								**320**	Load growth in the area, especially at Barkers Fruits, and planned load growth is restricted by line capacity.	110.4		
5	A	Reliability, Safety & Environment	Other			Distribution and LV lines	TEK	High	Simons Pass Fdr 22 kV to 11 kV			220										**220**	Along Clayton Rd, 25 poles @ $10k ea. 3 Year project to manage SAIDI's.	202.4		
6	A	Growth				Distribution and LV lines	BPD	High	Ikawai / Tawai 11 kV			100										**100**	From Balmoral substation. Removes health & safety issues with current substation. 17 Tx;'s and removal of sub.	92		
51	A	Growth				Subtransmission	BPD	Medium	Pub Road 33 kV						1200							**1,200**	9 km 33 kV Construction. Waituna Fdr for Waihao Downs Irrigation. Latest information is that Gary Rooney is not progressing this any firther due to lack of uptake from farmers.			
7	A	Refurbishment & Renewal				Distribution and LV lines	BPD	High	Waihao River crossing			40										**40**	2 km 11 kV Magpie to supply two ICP's same farmer.	36.8		
8	A	Growth				Subtransmission	BPD	High	Mt Harris 110 kV double circuit			30			3500							**3,530**		27.6		
9	A	Growth				Distribution and LV lines	STU	High	Morven regulator to Crowes Rd - Tawai Fdr rebuild			110										**110**	Budget to start concept design and surveying. Main budget expected to be spent when ODL applies for drier 3/4 supply.			
10	A	Asset Re-location				Distribution and LV lines	STU	High	Morven Fdr re-route at Leighbank			150										**150**	Replace 2.1 km conductor (Flounder) from Morven regulator to Crowes Rd.	138		
52	A	Growth				Distribution and LV lines	STU	Medium	Second 11 kV Fdr to CNR				115									**115**				
11	A	Reliability, Safety & Environment	Quality of Supply			Distribution and LV lines	CD1	High	Mackle Rd conductor upgrade			165										**165**	2.5 km Morven Glenavy Rd - rail xing	151.8		
53	A	Growth				Distribution and LV lines	STU	High	Otaio Fdr upgrade or alternative supply				400									**400**	11 kV North out of capacity. (see PAR)			
54	A	Reliability, Safety & Environment				Distribution and LV lines	TMK	Medium	Rebuild to heavy up feeder to vinegar factory in 11 kV	50	50	50										**50**	Light conductor in high fault level. Public safety. TDC council approval sought.			
12	A	Reliability, Safety & Environment	Quality of Supply			Distribution and LV lines	CD1	High	Looker Rd conductor upgrade				150									**150**	From T402 to T404, 3.5 km Mullet to Mink	0		
13	A	Growth				Distribution and LV lines	TMK	High	Springfiled Rd - Waitohi & Temuka West rebuild				200									**200**	From T593 to TX62, 3.2 km Magpie to Mink			
14	A	Refurbishment & Renewal				Distribution switchgear	Network	High	ABS replacements	270	140	110	60	60	60	60	60	60	60	60	60	**650**	Along Springfield Rd.	50		50
55	A	Reliability, Safety & Environment				Distribution and LV lines	RGA	Medium	Tie between Mahan Rd Fdr. & Main Sth Rd Fdr.			25										**25**	At Old Main Sth Rd & Ort Rga Mth Rd cnr			
56	A	Growth				Distribution and LV lines	PAR	High	St Andrews Fdr upgrade or alternative				400									**400**	11 kV South out of capacity. (see STU)			
57	A	Reliability, Safety & Environment				Distribution and LV lines	HNT	Medium	NST to Canada St (Hunt 2) replace Gopher 11 kV	45	45	45										**45**	Light conductor in high fault level. Public safety. TDC council approval sought.			
58	A	Reliability, Safety & Environment				Distribution and LV lines	HNT	Medium	Archer St (Hunt 11) replace 25 Cu 11 kV	25	25	25										**25**	Light conductor in high fault level. Public safety. TDC council approval sought.			
59	A	Reliability, Safety & Environment				Distribution and LV lines	TMK	Medium	St Leonards St - replace 16 Cu 11 kV	15	15	15										**15**	Light conductor in high fault level. Public safety. TDC council approval sought.			
15	A	Reliability, Safety & Environment	Quality of Supply			Distribution switchgear	Network	High	New ABS's			70	60	60	60	60	60	60	60	25	60	**575**	Replacement of known ABS which are failing and replacement with load breaks to improve network switching.	70		30
16	A	Growth				Distribution and LV lines	PAR	High	Sub transmission lines reconductor to Iodine	502	822	470	450								25	**945**	Pareora 33 kV 1 & 2 rebuild - Mink to Jaguar (2 x16 km). Current	432.4		170
60	A	Growth				Distribution and LV lines	STU	Medium	McNamara's Rd rebuild			250										**250**	SH 1 to WTE Cemetery, rebuild Ferret to Iodine 11 kV			
17	B	Customer Connection				Other network assets	Network	High	New Connections & Subdivisions			2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	**24,000**	New connections, subdivisions and extensions.	2208		750
18	D	Customer Connection				Distribution substations and transformers	Network	High	Transformers distribution for subdivisions, extensions & replacements	700	600	440	400	400	400	400	400	400	400	400	400	**4,040**	Transformers for new connections and subdivisions.			
18	A	Growth				Distribution and LV lines	ABY	High	Motukaika Rd - Cave Fdr upgrade			75									400	**475**	Transformer purchases. Reduction due to consignment stock.			
19	D	Growth				Distribution substations and transformers	Network	High	Voltage regulator & Capacitor Bank Installations	180	120	250	80	80	180	180	120	180	120	120	80	**1,390**	This budget item is related to loadgrowth. Due to the loads on our system and the connection of new loads we are experiencing voltage regulation issues which can be addressed by the installation of voltage regulators OR shunt capacitors at various locations. Shunt capacitors does however influence our load control capability since the capacitors absorb the ripple signals which results in failure to operate loads via this means. Budget based on $60k per capacitor installation, and $120k per regulator installation. A second Tx at BPD will reclaim 4 regulators.	115	115	130
20	D	Refurbishment & Renewal				Distribution substations and transformers	Network	High	Distribution Sub refurbishment	100	100	220	220	220	160	160	160	160	160	160	100	**1,720**		101.2	101.2	70
21	D	Refurbishment & Renewal				Distribution substations and transformers	Network	High	Two pole distribution sub refurbish.	160	160	170	160	160	160	160	160	160	160	160	100	**1,550**	Safety & reliability due to inadequate fault ratings, statter switch replacements due to condition and lack of maintenance, pole and structure condition assessmement, seismic strength of installation. Difficult to assign a unit cost as well as quantity per annum.	90	66.4	
22	D	Refurbishment & Renewal				Distribution switchgear	Network	High	Replacement RMU's	400	400	230	200	200	150	150	150	150	150	150	150	**1,680**		105.8	105.8	100
23	D	Growth				Distribution switchgear	Network	High	New RMU's			230	250	250	250	250	250	250	250	250	250	**2,480**	Budget for 4 RMU's at $50k ea.	105.8	105.8	100
24	D	Reliability, Safety & Environment	Quality of Supply			Distribution switchgear	Network	High	Reclosers New	120	160	200	180	180	180	180	60	60	60	60	60	**1,220**	Budgets are based on 6 sites per annum and $30k per site.	92	92	

25	D	Refurbishment & Renewal				Distribution switchgear	Network	High	Reclosers Replacements	120	100	100	122	122	122	122	122	60	60	1,050	This is a project to replace old ball & chain types which freezes up in winter resulting in faulty operation. They are also filled with oil which results in maintenance concerns. Two remaining out at Tekapo for replacement namely M142 & M210. M142 will need to be replaced with two breakers, one each side of transformer. Cooper reclosers are also being changed out, retro fitted with SEL relays and re-deployed on the network.	55.2	55.2	20
26	D	Reliability, Safety & Environment	Other			Other network assets	Network	High	Earthing	330	150	100	100	100	100	100	100	100	100	1,280	Results from earth testing program shows large number of sites outside of regulations. Budget based on 85 NB sites identified @ $2,500 per site. The budget for 2014/15 includes $150k for FLE, GLD & PLP substation earthing improvements.	303.6		150
61	D	Reliability, Safety & Environment				Distribution substations and transformers	HLB	Medium	11/22 kV Substation Upgrade final stage	150										150	Project importance dependant on resource availability.			
27	E	Growth				Distribution and LV cables	Network	High	Underground Cable Upgrades (G)	420	300	300	300	300	350	300	300	300	300	3,170	Project needs detailed planning. Many 11kV cables in CBD are at full capacity and needs upgrading. At estimated cost of $200/metre this allows for 2.5km per annum to be replaced. STAFFORD/BARNARD STREET!! HUNT RING - FREQUENT FAULTS IN THIS PART OF THE NETWORK.	386.4		200
28	E	Refurbishment & Renewal				Distribution and LV cables	Network	High	Underground Cable Upgrades (R)	220	220	220	220	220	300	300	300	300	300	2,600		202.4		100
29	E	Refurbishment & Renewal		Overhead to Underground		Distribution and LV cables	Network	High	O/H to U/G conversions	650	370	350	480	1000	2000	1000	1000	1000	1000	8,850	11 kV & 33 kV Overhead Lines in urban areas conversion to underground for Network reasons. These projects have been identified. There are however a number of instances where we have HV O/H lines going down the back residential properties. These need to be re-located to eliminate safety issues as well as improve maintenance access. Budgets can be delayed but should retain line item for when and if needed.	598		250
62	E	Reliability, Safety & Environment		Overhead to Underground		Distribution and LV cables	GRM	Medium	Wilson St U/G	807										807	585 meters of undergrounding as agreed with TDC.			
63	E	Reliability, Safety & Environment		Overhead to Underground		Distribution and LV cables	GRM	Medium	Chalmers St U/G 11 kV	360										360	215 meters of undergrounding replacing light overhead conductor			
64	E	Reliability, Safety & Environment		Overhead to Underground		Distribution and LV cables	GRM	Medium	Guiness St (GRM 7) U/G 11 kV	538										538	390 meters of undergrounding replacing light overhead conductor			
30	F	Refurbishment & Renewal				Zone substations	Network	High	Zone Substation Protection replacement	220	200	150	200	150	150	150	200	200	200	1,820	Replacement of old electromechanical or electronic relays that are at end of life, and upgrading of some existing protection.		160	
31	F	Reliability, Safety & Environment	Quality of Supply			Zone substations	Network	High	Mobile sub site preparations	220	200	150								570	Prep. 3 sites per annum @ $65k ea.	202.4		100
32	F	Refurbishment & Renewal				Zone substations	Network	High	33/22 kV CB & recloser replacement	100	75	75	75	75			150			550	Replacing old oil CB's with vacuuum CB's i.e. Unwin Hut, Albury, Haldon, Fairlie, Twizel, Tekapo	52	40	100
33	F	Refurbishment & Renewal				Other network assets	Network	High	Ripple Plant replacement & LS rework	160	400									560	Replace old rotary plant which is giving problems. Relays (in stock) must also be replaced.	57.2	90	
34	F	Refurbishment & Renewal				Other network assets	ABY	High	Ripple Relay Changeout	220										220	As part of the ripple plant replacement all the ripple relays needs to be changed out as well. This budget is based on 1600 relays and $250 per unit to change out. This budget will only be required IF the smart meter load control functionality does not perform as required.	160		160
65	F	Growth				Other network assets	BPD	Medium	Ripple Plant Enhancement to suit T1 addition		100									100				
66	F	Growth				Other network assets	STU	Medium	Ripple Plant Cell upgrade	100	50									150	Growth related. Keeping down of peaks to TP. To coincide with TP transformer upgrade planned for 2014/15.			
67	F	Reliability, Safety & Environment				Other network assets	TIM	Medium	Ripple Plant upgrade (x2)	400	400									800	Timaru TDC forms the bulk of Alpine's controllable load. If this plant fails we are in serious trouble. The intention is to have dual redundancy with the standby plant potentially mobile to also be used as emergency back-up for Albury, Studholme and Bells Pond.			
35	G	Growth				Other network assets	Network	High	New Equipment	150	150	150	150	150	150	150	150	150	150	1,500				
36	G	Customer Connection				Other network assets	Network	High	QOS Investigations	50	50	50	50	50	50	50	50	50	50	500	Budget used to record QoS parameters.		25	
68	H	Growth				Zone substations	GLD	High	Zone Substation upgrade		100	1800								1,900				
69	H	Growth				Zone substations	TRV	Medium	Totara Valley Zone substation build	60	1500									1,560	Based on load growth and line build to site.			
37	H	Growth				Zone substations	TIM	High	33 kV Upgrade	2000										2,000	This is a preliminary budget based on existing feeders and using the Portacom design at Pareora.	920	920	2000
70	H	Growth				Subtransmission	TIM	Medium	Cable two 33 kV circuits to Pages/Morgans Road			3100								3,100	Revise budget			
38	H	Refurbishment & Renewal				Other network assets	Network	High	Comms & RTU	100	50	50	50	50	50	50	50	50	50	550			50	
39	H	Refurbishment & Renewal				Zone substations	HNT	High	11 kV protection/control replacement (17 CBs)	530										530			487.6	
40	H	Refurbishment & Renewal				Zone substations	FLE	High	Substation upgrade	450										450	Bruno to review EPR issues	100	250	150
41	H	Refurbishment & Renewal				Zone substations	TEK	High	Change-out oil CBs for LMVP	120										120	Dave to check with RPS if they can re-work the Victoria St breakers for this purpose.		55.2	120
42	H	Growth				Zone substations	TEK	High	New transformer install	150										150			69	
43	H	Refurbishment & Renewal				Other network assets	Network	High	New SCADA Master Station	100	50	100	50	50	50	50	50	50	50	600	Replacing existing old mater station.			
71	H	Refurbishment & Renewal				Distribution substations and transformers	UHT	Medium	Sub (33/11 kV), change-out oil CBs for LMVP	40	0									40				
44	H	Reliability, Safety & Environment	Other			Other network assets	WDK	High	Communications room upgrade	120	100									220			55.2	50
45	H	Reliability, Safety & Environment	Quality of Supply			Other network assets	Network	High	SCADA & pole top equipment automation (e.g. reclosers)	220	200	200	100	150	150	150	150	150	150	1,620	Budget to establish communications network and automate pole mounted reclosers.		101.2	100
46	H	Reliability, Safety & Environment	Other			Other network assets	Network	High	Upgrade Security Lock/Key System for all Network Plant and Equipment, starting with Zone Substations.	200	100	100								400	Relacement of all old locks with new Abloy locks.			
47	H	Growth				Other network assets	Network	High	Consultants Reports	250	250	150	150	150	150	150	200	100	100	1,650				
72	I	Growth				Zone substations	SDW	Medium	33/11 kV New Zone Sub									2000	2000	4,000				
73	I	Growth				Subtransmission	SDW	Medium	33 kV cable (say 4x4km + 1x2km) from TIM run at 11 kV initially	100		4000								4,100	New cables to supply new SDW substation. Initially to alleviate load on Seadown Fdr. and Meadows Rd Fdr.			
74	I	Growth				Zone substations	SDW	Medium	33/11 kV Zone Sub mesh existing network to station			500								500				
48	H	Growth				Zone substations	BPD	High	Second 11 kV Switchboard for T1		450									450				
									Total	**$ 17,035**	**$ 15,490**	**$ 18,155**	**$ 13,147**	**$ 8,967**	**$ 9,842**	**$ 8,852**	**$ 9,042**	**$ 10,695**	**$ 10,995**	**$ 122,220**		**$ 8,323**	**$ 2,945**	**$ 5,400**
									Last Years prediction	**12,905**	**10,785**	**12,498**	**5,622**	**6,172**	**7,097**	**5,157**	**4,947**	**4,535**				**Total**	**$ 11,267**	

Appendix D schedule 14a

Company Name Alpine Energy Limited
For Year Ended 31 March 2014

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

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.

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, to derive the 10 year forecast. 2% was selected as a conservative inflationary rate based on New Zealand Treasury 10-year outlook. 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 deflated by approximately 2% per annum, on a straight-line basis, to derive the 10 year forecast. The 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 customers 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.

Glossary

The following acronyms and abbreviations are used throughout the Asset Management Plan.

A – Ampere

AAC – All Aluminium Conductor

AAAC – All Aluminium Alloy Conductor

ABS – Air Break Switch

ACSR – Aluminium Conductor Steel Reinforced

ABY – Albury Transpower substation

ADMD – After Diversity Maximum Demand

AEL – Alpine Energy Limited

AMMAT – Asset Management Maturity Assessment Tool

AMP – Asset Management Plan

Al – Aluminium

BCL – Broadcasting Communications Ltd

BPD Bell's Pond Substation

Bus – Busbars

CAPEX – Capital Expenditure

CB – Circuit Breaker

CBD – Central Business District

CDEM Act – Civil Defence Emergency Management Act

CFC – Greenhouse Gas

CFL – Compact Fluorescent Lamp

Cu – Copper

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
GEC	–	General Electric Company
GIS	–	Geographic Information System
GST	–	Goods and Services Tax
GWh	–	Giga Watt Hours
GXP	–	Grid Exit Point
Hz	-	Hertz
ICP	–	Installation Control Point
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
NIWA	–	National Institute of Water and Atmosphere Research
OCB	–	Oil Circuit Breaker
OC	–	Overcurrent
ODV	–	Optimised Deprival Valuation
OCTC	–	Off Current Tap Changer

OLTC – On Load Tap Changer

OPEX – Operating Expenditure (including maintenance spend)

PAM – PAS 55 Assessment Methodology

PAS 55:2008 – Publically Available Specification number 55

PC's – Desktop Computers

pd – potential difference

PD – Partial Discharge

PIL – Paper Insulated Lead

PILCSWA – Paper Insulated Lead Steel Wire Armoured cable

POS – Point Of Supply

pu – per unit

PWC – Price Waterhouse Coopers

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

STU – Studholme Transpower substation

SVC – Static Var Compensation

TDC – Timaru District Council

THD – Total Harmonic Distortion

TIM – Timaru Transpower substation

TKA – Tekapo Transpower substation

TMK – Temuka Transpower substation

TPNZ – Transpower

TWZ – Twizel Transpower substation

TVS – Twizel Village substation

UHF – Ultra high frequency

VHF – very high frequency

VLF – very low frequency

V – Volts

VCB – Vacuum Circuit Breaker

WDC – Waimate District Council

XLPE – cross linked polyethylene cable

YNd9 – Transformer vector group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