ALPINE ENERGY LIMITED

Asset Management Plan 2013-2023

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Foreword

Alpine Energy Limited's (AEL) 2013 Asset Management Plan (AMP) has been written to provide customers and stakeholders with insight and explanation on how AEL intends to provide electricity distribution services to South Canterbury consumers. AEL will achieve this purpose by managing and operating its distribution assets in a safe, reliable, and cost effective manner that addresses required service levels and maintains a robust energy delivery system for its consumer.

AEL's distribution network is in a fair to good condition and while a number of assets built in the 1950's and 1960's are nearing the end of their expected service life, for the majority of these older assets, their general condition is such that they will be able to safely continue service for the next eight to ten years.

Assets that have served their useful life or have developed defects to the point that it is uneconomic to prolong their service will be retired and replaced with alternative products.

AEL continues its reinvestment phase by identifying and committing funds for a number of network developments. These are developments that have been identified to best serve our customers for the next 50 years (the average life of an electricity distribution asset).

AEL has restructured its tariffs and pricing methodology that allows it to stay within the default price path set by the Commerce Commission.

Capacity increases at Transpower supply points will be through new investment agreements with a resulting price pass through to customers as is presently the case. Where sole beneficiaries are identified for additional capacity, AEL will insist on back-to-back agreements to minimise the risk to consumers of stranded assets.

Comments are encouraged from our customers 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 AEL and represents AEL's intentions and opinions at the date of approval – 28 March .

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

AEL 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.

Glossary

The following acronyms and abbreviations are used throughout the Asset Management Plan.

A	–	Ampere (or “Amp”)
AAC	–	All Aluminum 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 (TP use ALP)
AMMAT	–	Asset Management Maturity Assessment Tool
AMP	–	Asset Management Plan
BCL	–	Broadcasting Communications Ltd
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
DCIU	–	Data Control & Interface Unit
DGA	–	Dissolved Gas Analysis
DNP	–	direct Numeric Protocol
DO	–	Drop Out fuse
Dyn	–	Transformer vector group
EC	–	Electricity Commission
EDB	–	NZ Electricity Distribution Businesses
EEA	–	Electricity Engineers’ Association
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
kV	–	kilo Volt
kVA	–	kilo Volt Amp
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 Amp
MW	–	Mega Watt
N-1	–	reliability measure, where n systems can lose 1 element and still
NIWA	–	National Institute of Water and Atmosphere Research
NZDL	–	New Zealand Dairies Ltd
OCB	–	Oil circuit breaker
ODV	–	Optimised Deprival Valuation
OCTC	–	Off Current Tap Changer
OLTC	–	On Line 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	–	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
UHF	–	Ultra high frequency
VHF	–	very high frequency
VLF	–	very low frequency

WDC	–	Waimate District Council
XLPE	–	cross linked polyethylene
YNd9	–	Transformer vector group

1.1 The Purpose of the Plan

The purpose of this Asset Management Plan (AMP) is to define how AEL will develop, manage and maintain its network equipment to provide a safe, reliable, efficient and cost effective energy delivery system.

The AMP identifies the major initiatives and projects to be undertaken over the planning period to meet stakeholder and customer requirements. Preparation of the AMP in this format assists AEL 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].

1.2 Period Covered

The planning period of the Asset Management Plan is from 1 April 2013 until 31 March 2023. The AMP is reviewed annually and has been approved by the Alpine Energy Directors on 28 March .

The planning period extends to the optimised lifetime of the present network equipment. However, the main focus of the plan is the initial five year period following the plan's review date, with particular emphasis on the first 12 months of this period. Beyond this time, analysis tends to be more indicative, based on long-term trends.

It is likely that new developments that are not identified here will arise during the latter part of the planning period. In particular large blocks of new load such as dairy factories are difficult to predict more than a few years in advance and significantly alter demand projections because they are large relative to AEL's demand.

1.3 Key Assumptions

Each review of the Asset Management Plan is predicated upon a series of key assumptions that are made as a foundation for planning and forecasting of future activities, whether investing to maintain, replace or develop new assets.

The key assumptions for the 2013-23 AMP are as follows:

During the 2012/13 financial year, NZ 90 Day Bank Bill interest rates have fallen from a 2012 high of 2.75%, down to 2.53% in June, and then rose to about 2.63% in July where rates held into November 2012. Both NZ and overseas sources had suggested that the low interest rates were

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

likely to rise slowly during the 2012/13 financial year, the opposite has occured. These low interest rate conditions should allow investment to continue at rates proposed in the AMP. However, the NZ Reserve Bank has recently warned of the risks to the NZ Economy posed by NZ's high external debt relative to GDP in event of a deteriation in offshore markets affecting the price or availability of debt (Refer to the RBNZ "Financial Stability Report" of November 2012).

While NZ agricultural export earnings have fallen over the past six months due to lower export commodity prices and the appreciation of the NZD, recently, NZ's export commodity prices appear to have stabilised (as at November 2012).

NZ's GDP growth has been relatively steady at about 2% since 2010.

The ANZ Regional Trends report of November 2012 indicates "an atmosphere of genuine optimism" in Canterbury. In 2012, as at November, employment had risen 2.9% compared with an unchanged figure nationally. However, most of this is probably associated with the earthquake recovery in Christchurch.

New connection inquiries with demand for additional load has been steady in 2012, particularly for irrigation, dairy and other rural applications.

Shareholder structure of Consumer Trust and three District Councils will continue their investment in the business at current rates of return.

Revenue streams from network investments, apart from seasonal variations, will increase as increasing electrical capacity will lead the load demand which will follow. As the economy picks up, the increased capacity headroom will allow connection of new development rather than continue the constraints previously existing in some irrigation/dairy areas.

AEL recognises that the economy depends on a secure and reliable supply of electricity.

In November 2012 the Commerce Commission reset the default price path that applies to all non-exempt electricity distribution businesses, including AEL, for the next two years (2013/14 and 2014/15).[2] Under the reset AEL's price increases are capped at CPI+10% in each year. The cap, as it is determined by the Commerce Commission, requires AEL to increase its prices by CPI+10% in 2013/14 and 2014/15 or forgo revenue.

AEL will comply with the price path and will not increase prices higher than the price cap in either year. However, in reaching a decision as to the appropriateness of pricing up to the price cap we

[2] Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2012, NZCC 35, 30 November 2012.

will consider both our obligation to ensure an appropriate return to our shareholders and equitable price increases to our consumers.

AEL has segmented capital investment over the AMP period based on projects which must go ahead. These projects are required due to capacity or security constraints. Some projects will be conditional on third party decisions or developments such as customer projects proceeding, resource consets around irrigation schemes, etc. Appendix C.4 summarises the capital spend projects into these categories.

A number of transmission projects are also required to provide adequate security and capacity at the Grid Exit Points (GXP) or transmission lines within the region. It is assumed that these projects outlined will proceed either under a customer investment contract with Transpower, with a cost pass through to customers, or first pass the grid investment test applied by the Commerce Commission.

AEL's AMP is a pivotal document to convey future network development and maintenance plans to shareholders and the general public, as well as being an essential working document for AEL's management and staff.

Establishment of service levels continues to be through consultation with stakeholders and remains a balance between customer needs, price-quality tradeoffs and industry best practice.

The Commerce Commission applies the Grid Investment Test and from its findings will approve or decline recovery of expenditure for the 110 kV non-core transmission grid assets. These assets include the Lower Waitaki Valley circuits and 110kV line through to Timaru and that allows supply security and reliability to be maintained and for economic growth to continue throughout the region.

It is assumed that no new technology will be developed within the planning period that substitutes for electricity network development. Distributed Generation is viewed as an enabling technology for network support, rather than network replacement.

AEL's asset management systems continue to process performance information to meet demand, capacity, security and reliability levels in a timely manner.

Growth is seen to be close to long-run averages throughout the planning period as the economy benefits from high commodity prices, despite the deflationary impact of the high exchange rate. There will be other infrastructure activities, like irrigation scheme development, that continues through the period subject to available financing.

Uptake of heat pumps will have an impact on network capacity. Changes in feeder demand will be monitored to confirm that the expected impact will not cause large constraints.

Transpower GXP capacity, grid support projects and security requirements will be delivered to continue current service levels. The costs of maintaining these service levels are passed directly through to customers.

AEL will:

- Retain use of associated company NetCon as preferred contractor for construction and maintenance services;
- Ensure compliance with relevant Acts and Regulations.
- Meet the requirements of our Shareholders by achieving the objectives set down in AEL's mission statement.

Asset Management Planning involves forecasts based on information assembled from many sources. Network development for the next 3 years is firm, however beyond this point, planning is less certain and requires regular review of information and further assessment to ensure best industry practice is achieved.

Review of future achievement, apart from regulatory compliance which is non-negotiable, will be centred on the following areas:

- Safety performance
- Financial performance
- Economic efficiency performance
- Reliability measures
- Utilisation performance
- Environmental performance

1.4 Asset Management Systems

Asset management systems used by AEL include asset databases, system reliability and condition assessment databases, load flow analysis software, maintenance and SCADA records. Contracts management practices have been established for all external Contractors who carry out work on the Network. Work on the network carried out by Netcon is managed through a Service Level Agreement which is continually reviewed and updated as required.

The asset database will be further improved in conjunction with the IT development project. (Refer to database development comments in §1.8, below).

Load flow analysis software is performing well with reliable representation of the effect of network growth on the performance of the existing network.

1.5 Network & Asset Description

The AEL Network supplies electricity to 30,612 customer connection points throughout South Canterbury. Electricity is delivered to the AEL Network via seven Grid Exit Points and one embedded generator. The Network delivers some 708 GWh of energy annually and had a ½ hr average coincident Maximum Demand of 113 MW recorded in May 2012. The GWh are up from the previous high of 705 GWh but the Maximum Demand is marginally down from 116 MW for October of the previous year. These results were due mainly to increased heating load from a cold, wet, winter and reduced irrigation as a result of a wet spring.

The area of supply covers approximately 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 on Figure 3.1.

A breakdown of the value of the assets is given in Appendix A.

1.6 Service Levels

Levels of service are set by AEL in conjunction with shareholder and customer's expectations. Reliability levels are determined by the quality standards set the Commerce Commission under the default price-quality path.

AEL maintains a close relationship with customers to discuss the aspects of price/quality trade offs associated with levels of service and reliability determined by present network configuration or opportunities for an enhanced supply. This provides an understanding of the present level of network performance and the available options for the customer's reliability expectations to be developed.

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

1.7 Network Development Plans

Asset enhancement and development projects have been identified through either consumer requests or network studies. Condition and performance grades for determining the economic life of the asset have been based on published Ministry of Economic Development guidelines.

The large size of new loads such as dairy factories makes any sort of projection difficult. Locations nearer to existing GXP's or where a new GXP can be readily developed adjacent to the transmission network, allow 5 MW of new load to be supplied with lesser difficulty. Unfortunately electricity supply is only one factor considered when establishing large industrial loads – with priority given to transport corridors, land use restrictions, labour force, etc.

Table 1.1over page lists the Capital Expenditure forecast for the next ten years. The figures are a summary of Appendix C. Costs are GST exclusive and in 2013 equivalent dollars.

1.8 Life Cycle Asset Management

The age information of the existing assets is held within databases and is used as a guide for setting inspection cycles to determine asset condition. Information on major maintenance, refurbishment, or replacement of the asset is recorded in the database and on existing plans. The confidence level of the asset condition and performance continues to improve as further data is collected and updated. AEL purchased a GIS platform in 2006 and has embarked on a conversion project where 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 an ongoing process.

A review of the existing "legacy" databases (electronic and paper based) is currently being undertaken with a view to recommending an update to the overall "asset management system" to improve efficiency, reliability, and usability of the system. (The GIS System is a component, along with the various databases, of the present "asset management system").

1.9 Operation and Maintenance Expenditure

The operation and maintenance expenditure including lines and cables, distribution transformers, substations, SCADA and communications is summarised in Table 1.1 over page. Maintenance expenditure is forecast to increase through the planning period.

Table 1.1 provides forecasts of Operational Expenditure for categories of: routine & preventive maintenance; refurbishment & renewal maintenance; and fault & emergency maintenance.

Following the introduction of centralised control by AEL in 2009, the Fault & Emergency Maintenance category now includes the cost of the contracted fault services (estimated at $1,000,000 for 2010-11) which previously had been an internal AEL overhead cost.

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.

AEL maintenance policies include routine and special inspections to ascertain asset condition and regulatory compliance. These policies rank public and environmental safety as a top priority.

Health and Safety

AEL upholds excellence in health and safety management. We will at all times ensure that work that we do is safe in order 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 & Safety management programs and staff safety and competency certification.

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; and
- Electricity Authority approved Participant Outage Plan as required under the Electricity Governance (Security of Supply) Regulations 2008; and
- Other contingency plans for electricity restoration (being developed in conjunction with the above).

AEL is also 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 CDEM Act.

Environment

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

1.11 Evaluation of Performance

Asset management performance is continuously measured against this Asset Management Plan.

Plans to maintain & improve the performance of the AMP and network are based on:

- Improving condition based maintenance strategies,
- Adopting new and improved maintenance techniques and technologies,
- Refining the planning for new development projects to meet the need for renewal, upgrading, and extension of the Network,
- Reviewing the asset management system with a view to updating and/or replacing its existing components,
- Auctioning Commerce Commission AMP Review Report recommendations for achieving compliance.

1.12 Expenditure Forecasts & Reconciliation

The following Table 1.1 and Table 1.2 present the information required by the “Asset Management Plan Requirement: Expenditure Forecasts and Reconciliation”.

Please also refer to Section 5 “Network Development Planning” and to Section 6 “Lifecycle Asset Management Planning” for more detail concerning the capital and operational expenditure and projects and work to be undertaken during the 10 year planning period.

- ***Table 1.1: AMP Ten Year Forecasts of Expenditure (in $'000 and constant prices)***

Asset Management Plan Requirement: Expenditure Forecasts & Reconciliation

	Actual for most recent financial year	**Forecast current year (CY)**	**Forecast Year**									
Capital Expenditure (CAPEX)	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**
Customer connection	2,660	2,250	2,650	2,150	2,150	2,150	1,850	1,850	1,850	1,850	1,600	1,600
System growth	12,550	6,339	9,047	5,932	5,382	7,630	830	830	770	830	770	770
Asset replacement and renewal	2,048	5,516	3,524	3,653	2,333	2,228	2,442	2,242	2,292	2,292	2,392	1,980
Asset relocations	0	0	0	0	0	0	0	0	0	0	0	0
Reliability, safety and environment	798	2,325	5,841	1,170	920	490	500	1,250	2,185	185	185	185
Subtotal - expenditure on network assets	*18,056*	*16,430*	*21,062*	*12,905*	*10,785*	*12,498*	*5,622*	*6,172*	*7,097*	*5,157*	*4,947*	*4,535*
Capex on non- network assets	722	640	1,312	640	690	640	360	585	340	290	315	405
Total CAPEX	**18,778**	**17,070**	**22,374**	**13,545**	**11,475**	**13,138**	**5,982**	**6,757**	**7,437**	**5,447**	**5,262**	**4,940**
Operational Expenditure (OPEX):												
Service interruptions and emergencies	1,170	1,127	1,463	1,454	1,455	1,436	1,411	1,379	1,356	1,325	1,270	1,240
Vegetation management	92	103	121	120	120	119	117	114	112	110	105	103
Routine and corrective maintenance and inspection	2,189	2,475	2,904	2,886	2,889	2,851	2,800	2,737	2,692	2,631	2,522	2,462
Asset replacement and renewal	643	1,539	786	781	782	772	758	741	729	712	683	666
Subtotal – network OPEX	*4,094*	*5,245*	*5,275*	*5,242*	*5,247*	*5,178*	*5,086*	*4,971*	*4,890*	*4,778*	*4,580*	*4,471*
Opex on non-network assets	8,305	10,146	10,233	10,565	10,628	10,659	10,582	10,531	10,495	10,473	10,459	10,466
Total OPEX	**12,399**	**15,391**	**15,508**	**15,807**	**15,875**	**15,837**	**15,667**	**15,502**	**15,385**	**15,252**	**15,039**	**14,937**
Total Expenditure on Asset Management	**31,117**	**32,461**	**37,882**	**29,352**	**27,350**	**28,975**	**21,649**	**22,259**	**22,822**	**20,699**	**20,301**	**19,877**

Notes: AEL's o/h to u/g expenditure is from within the Asset Replacement &Renewal budget.

More detailed forecast capex and opex information, including forecast in nominal dollars, can be found at Schedules 11 a and 11b at Appendix I.

▪ *Table 1.2: Variance between Actual Expenditure and Previous Year Forecasts*

Asset Management Plan Requirement: Expenditure Forecasts & Reconciliation (continued)			
B) Variance between Actual Expenditure and	**Actual for most recent financial year**	**Previous forecast for most recent Fincl Year**	
	2011/12	2011/12	% variance
Capital Expenditure (CAPEX):	(a)	(b)	(a)/(b)-1
Customer Connection	2,660	2,298	15.8%
System Growth	12,550	13,894	-9.7%
Asset Replacement and Renewal	2,048	2,303	-11.1%
Reliability, Safety and Environment	798	2,073	-61.5%
Asset Relocations	0	0	Not defined
Subtotal - Capital Expenditure on Asset	18,056	20,568	-12.2%
Operational Expenditure (OPEX):			
Routine and Preventative Maintenance	2,280	2,273	0.3%
Refurbishment and Renewal Maintenance	644	757	-14.9%
Fault and Emergency Maintenance	1,170	2020	-42.1%
Subtotal - Operational Expenditure on Asset	4,094	5,050	-18.9%
Total Direct Expenditure on Asset	22,150	25,618	-13.5%

Note to Table 1.1: AEL reported forecast expenditure of $455k for the 2012-13. However, following the Canterbury earthquakes AEL stopped undergrounding distribution lines, hence the zero expenditure in 2011-12, and the revised forecast is zero.

Note to Table 1.2: for the following category actual expenditures for 2012-13:
Customer Connection: overspend resulting from a higher number of customer connections than forecast;
Reliability, safety and environment: underspend due mainly to $800k forecast for ripple plant being delayed until after 1st April 2012;
Replacement and renewal: underspend due mainly to the prioritisation of resources to higher priority projects;
Fault and emergency maintenance: underspend relates directly to the number and severity of network emergencies experienced in the period being less than expected from recent experience;
Refurbishment and renewal maintenance: underspend mainly due to the re-assignment of resources due to re-prioritisation of projects within the CAPEX programme

2.

Background & Objectives

Background and Objectives

The Asset Management framework embodied in the AMP has been developed to link AEL's strategic objectives through to the Asset Management activities of the AMP. Thus the AMP includes a hierarchy, or framework, of Asset Management policy, strategy and plans that:

- Links organisational strategic objectives with the Asset Management policies and objectives needed to deliver them;
- Links organisational strategic objectives with the levels of service that the assets should deliver; and
- Guides the Asset Management priorities, the work required on the assets to achieve those objectives, and the finances needed to support that work.

2.1 Purpose of the AMP

The purpose of the AMP is to provide a governance and management framework to ensure that AEL:

- Sets service levels for its electricity network that will meet customer, community and regulatory requirements.
- Understands what levels of network capacity, reliability and security of supply will be required both now and in the future, and the drivers behind these requirements.
- Has a robust and transparent processes in place for managing all phases of the network life cycle from the proposal phase to the de-commissioning.
- Has adequately considered the classes of risk its network business faces, and that it has systematic processes in place to mitigate identified risks.
- Has made adequate provision for funding all phases of the network lifecycle.
- Makes decisions within systematic and structured frameworks at each level within the business.
- Has an ever-increasing knowledge of its asset locations, ages, conditions and the networks' likely future behaviour as it ages.

Disclosure of the AMP in this format will also assist AEL in complying with the requirements of the Commerce Commission's "Electricity Distribution Information Disclosure Determination 2012" and the "Attachment A - Asset Management Plans" of that document of 1st October 2012.

This AMP is not intended to be a detailed description of AEL's assets (these lie in other parts of the business), but rather a description of the thinking, the policies, the strategies, the plans and the resources that AEL uses to manage the assets.

2.2 Planning & Operating Contexts

All of AEL's assets exist within a strategic context that is shaped by a wide range of issues including: AEL's Statement of Corporate Intent, Mission Statement, Asset Management Policy and asset strategy; the prevailing regulatory environment; government policy objectives; commercial and competitive pressures; and technology trends. AEL's assets are also influenced by technical regulations, asset deterioration and various risk exposures independently of the strategic context.

2.2.1 Strategic Context

AEL's strategic business planning takes cognisance of a number of key factors such as:

- The prevailing regulatory environment, which constrains prices, requires no material deterioration of the network and requires compilation and disclose of performance and planning information.
- Government policy objectives, such as the promotion of distributed generation, low use tariffs and energy strategy objectives.
- AEL's commercial goals, which are primarily to deliver a sustainable earnings stream to the shareholders.
- Competitive pressures from other lines companies who might try to cherry-pick our high value customers.
- Pressure from Environment Canterbury to improve air quality by reducing domestic coal and wood fires.
- The need for water to irrigate pasture land, and Environment Canterbury's associated policies.
- Advancing technologies, such as distributed generation and "smart metering", that could strand parts of conventional lines businesses, force changes in the components, structure and operation of other parts of the network, and encourage development or evolution of a so-called "smart network".
- Changes to the South Canterbury climate that may include a more marked seasonality and extremes of weather. (Recent MFE global climate change forecasts for NZ are discussed later in this section).
- Local, national and global economic cycles, in particular the relative value of dairy products compared to other pastoral commodities that drive the rate of dairy conversions and system loads patterns.
- Interest rates and the general business confidence in the South Canterbury community which can influence the rate at which new customers connect to lines networks, particularly dairy conversions.
- The affects of the down-turn in the global economy and the state of the international banking sector affecting the availability of funds, and the consequential drop in confidence in property, share and commodity markets.
- Ensuring sufficient funds and skilled people are available in the short, medium, and long term to resource our service requirements.

2.2.2 Independence from strategic context

While AEL's assets and asset configuration will be shaped by the strategic factors identified in section 2.2.1 that are relevant to its stakeholders, it is also important to recognise that the assets will also be influenced (and sometimes constrained) by factors that are independent of the strategic context.

An example is the rate at which wooden poles rot which is independent of the scarcity of skilled contractors. This issue may constrain the rate at which AEL replaces rotten poles, but it does not influence the rate of rot.

Examples of factors that are independent of AEL's strategic context include:

- Technical regulations: including such matters as limiting interference and harmonics or maintaining power factor to specified levels.
- Asset configuration, condition and deterioration: these parameters will significantly limit the rate at which AEL can re-align its existing electric line assets to fit changing strategic goals (AEL has 4,007 km of O/H lines and U/G cables, and 5,426 transformers already in place).
- The physical characteristics of electricity networks which govern such fundamental issues as power flows, insulation failure, and faults.
- Physical risk exposures: exposure to events such as salt spray, wind, snow, earthquakes and vehicle impacts are generally independent of the strategic context. Issues in which AEL's risk exposure might depend on the strategic context could be in regard to natural issues such as climate change (increasing severity and frequency of storms) or regulatory issues (e.g. if NZTA required all poles to be moved back from the carriage way).
- Safety requirements such as earthing of exposed metal and line clearances.

2.3 Key Planning Documents

The relatively small size of the AEL business does not require the production of a formal business plan each year. AEL produces instead, a suite of annual documents, namely the Statement of Corporate intent, Asset Management Plan, Network Development Plan and Annual Works Plan which meet the objectives and outputs of an annual business planning process.

These key planning documents are described in more detail in the following sub sections.

2.3.1 Statement of Corporate Intent

AEL's Statement of Corporate Intent (SCI) 2013/14 is a requirement under Section 39 of the Energy Companies Act 1992, and forms the principal accountability mechanism between AEL's board and the four shareholders.

The SCI sets out the overall intentions and objectives for AEL for the three financial years, 2010 to 2013. The following information is also presented:

- The Objectives of the Company, including:
    - Mission
    - Business Plan Goals
- 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

2.3.2 Mission Statement and Business Plan Goals

AEL's Mission Statement is:

"To ensure continuing commercial success by:

- *Providing safe, efficient, reliable 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."*

AEL's Business Goals as related to various stakeholders are:

- Shareholders—to pursue business policies that will maximise the value of the company in the medium and long term.

- Customers—to provide customers with the safe, efficient, economic, and reliable delivery of energy and services.

- Efficient Use of Resources—to promote energy efficiency and effective utilisation of resources under our management.

- Human Resources—to be regarded as a fair and reasonable employer in our region and a company for whom staff are proud to work.

- Public and Social Responsibility—to be a law abiding and responsible company.

2.3.3 Strategic plan

To achieve AEL's Goal of "Commercial Success in the Delivery of Energy", AEL has adopted a Strategy to optimise its performance of operating, maintaining, and developing the AEL Network asset. The drivers for performance optimisation are:

- Safety,
- Efficiency,
- Reliability,
- Cost Effectiveness,
- Provision of Asset Management Services,
- Encouragement of the use of water resources to support production and utilisation of electricity.

This Asset Management Plan sets out the Actions and Strategies to achieve these Objectives.

These actions include:

- Network Operations to maintain and develop network Service Levels;
- Network Development Planning to respond to network growth and change, eliminate or mitigate risks through design, and to maximise the Network's value within the constraints of the AMP;
- Lifecycle Asset Management to maintain the Network in an optimum safe and operational condition, and maintain or improve its value;
- Risk Management to uphold safety, and identify, analyse, evaluate, and treat risks to the Network; and to protect its value;
- Evaluation of Performance to allow improvement and evolution of the AMP, and of the Network and the systems used to manage it;
- Financial Management to ensure economic success of the AMP and improvement of the value of the Network.

Each of these Actions includes detailed strategies and plans, as described in their respective Sections of this AMP.

2.3.4 Asset Strategy

The strategy which has evolved, and forms the basis communicated within the 2013 AMP, centres upon the following guiding principles:

- Maintain forefront for Company & customers awareness of safety around electricity

- Assist Transpower to upgrade the Timaru GXP with the replacement of the existing 11 kV switchboard and maintaining Timaru as a 11 kV GXP for the foreseeable future.
- Exploit the proximity of Transpower's 110 kV circuits to AEL's emerging load in the back country to eliminate 33 kV and take 110/11 kV supply directly from Transpower.
- Assist Transpower with plans for improved supply capacity while sharing risk of pre-contingent events.
- Develop the AEL 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.

The implications of these guiding principles are described in Section 3.

2.3.5 Prevailing Regulatory Environment

AEL is an electricity distribution lines services and as such is a regulated service under Part 4 of the Commerce Act 1986.

The purpose of Part 4 is to promote the long-term benefit of consumers, in markets where there is little or no competition and little or no likelihood of a substantial increase in competition, by promoting outcomes that are consistent with outcomes produced in competitive markets.

Part 4 is administered by the Commerce Commission. Through its regulatory instruments AEL, as a regulated supplier is:

- incentivised to
  - innovate and to invest in its network, including in replacement, upgraded and new assets
  - improve efficiency and provide services at a quality that reflects consumer demands
- required to share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices
- limited in its ability to extract excessive profits.

As a regulated service AEL is subject to information disclosure requirements and price-quality regulation. A short outline or both forms of regulation is provided in the sections below.

Information disclosure regulation

The purpose of information disclosure regulation is to ensure that sufficient information is readily available to interested persons (including the Commerce Commission) to assess whether the purpose of Part 4 is being met.

Under the information disclosure requirements, applicable to electricity distribution services, AEL is required to report its financial and reliability performance, prices and pricing methodology, and forward-looking information (such as forecasts and asset management plans) on an annual basis.

Default/customised price-quality regulation

The purpose of default/customised price-quality regulation is to provide a relatively low-cost way of setting price-quality paths for regulated suppliers, while allowing the opportunity for regulated suppliers to have alternative price-quality paths that better meet their particular circumstances.

In late November 2012 the Commerce Commission reset the default price-quality path (DPP) that will apply to the last two years of the current regulatory period (2013/14 and 2014/15). Under the DPP reset AEL is subject to a CPI+10% price cap. This means that we must increase our prices by CPI+10% or forgo the revenue.

Should we determine that the DPP is not appropriate to meet our needs we can apply to the Commerce Commission for a customised price-quality path (CPP). A CPP would be tailored to meet AEL’s needs must be consistent with the applicable input methodologies and will apply for five years.

2.3.6 Annual Works Plan

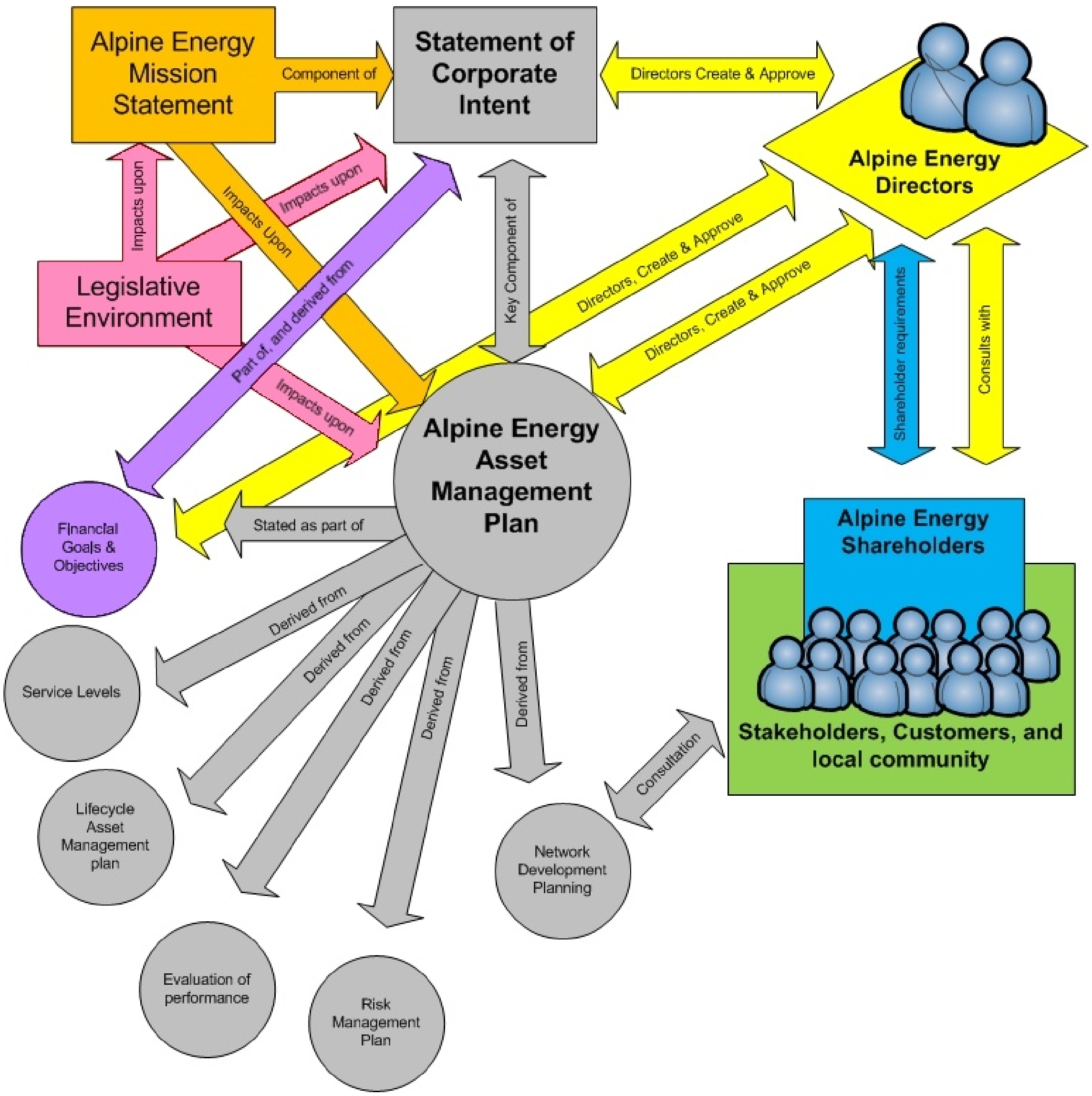
Each year we consolidate the first year of the AMP and any recent commercial, asset or operational issues into our annual works plan which defines the priorities and actions for the year ahead and which will contribute to our long-term alignment with the strategic context. We fully understand that this alignment process is very much one of “moving goal posts”.

An important component of the annual business planning is the annual works program which scopes and costs each individual activity or project that we expect to undertake in the year ahead.

A critical activity for us is to firstly ensure that this annual works program accurately reflects the current years’ projects in the AMP and secondly ensure that each project is implemented according to the scope prescribed in the works program.

2.4 Interaction of Drivers & Documents

Interaction of the key issues, processes and documents are shown in Figure 2.1 below.



▪ ***Figure 2.1: Interaction of key processes & entities***

2.4.1 Relationships with Other Planning Documents

This AMP is a key component of AEL's planning process. The following AEL documents are linked in this process:

- Statement of Corporate intent,

- Asset Management Plan,
- Network Development Plan,
- Health and Safety Management Plan,
- Capital Expenditure and Operational Expenditure (CAPEX and OPEX), and
- Monthly Board Reports.

2.5 Period Covered by this AMP

This revision of this AMP covers the period 1 April 2013 to 31 March 2023. This AMP was prepared during the period of October 2012 to March 2013, approved by AEL's Board on the 28 March 2013 and publicly disclosed by the 31st of March 2013 in accordance with the Electricity Distribution Information Disclosure Determination 2012[1].

The statistics relating to performance against plan are taken from the last financial year summary details (2011/2012) 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 level of this 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 AEL's 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 customers' expectations into the future.

Accordingly AEL has attached the following certainties to the timeframes of the AMP:

- *Table 2.1: AMP Timeframe Certainties*

Timeframe	Residential & 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

[1] Commerce Commission, Electricity Distribution Information Disclosure Determination 2012, Decision No. NZCC 22, 1 October 2012, clause 2.4.1.

Timeframe	Residential & commercial	Large industrial	Intending generators
Years 7 to 10	Reasonably certain	Little if any certainty	Little if any certainty

2.6 Managing Stakeholder Interests

2.6.1 Identifying Stakeholders

AEL is jointly owned by a Consumer Trust, and three District Councils. Other stakeholders include;

- The Electricity Retailers, contracted customers, and end consumers
- Contractors and associated equipment and service providers
- Embedded Networks
- Transpower
- Tree Owners
- AEL's contracting companies including the primary contractor, NetCon
- The public at large (as distinct from their role as electricity consumers) including their role as motorists in which they can reasonably expect AEL assets to be set back from the carriage way.
- Government agencies such as the Electricity Authority, the Commerce Commission, the Ministry of Economic Development, the Electricity & Gas Complaints Commission, Energy Safety Service and the Ministry of Consumer Affairs that have statutory obligations to oversee various aspects of ELB's operations.
- NZTA and District Council's as road corridor operators
- District and Regional Councils as statutory planning bodies
- Land owners across whose land AEL lines run
- Generators

AEL has close contact with all of its key stakeholders. Stakeholder feedback is welcomed as it provides AEL with opportunities to improve the way we conduct our business and provides a consumer perspective on the trade–off between price and quality.

2.6.2 Stakeholder Interests

Stakeholder interests are always considered in conjunction with AEL's mission statement. This allows consistent management of conflicting stakeholder interests. The interests of AEL's stakeholders are defined in the following table:

▪ *Table 2.2: AEL Stakeholder Interests*

Stakeholders	Interests				
	Viability	Price	Supply quality	Safety	Compliance
Line Trust South Canterbury	✓	✓	✓	✓	✓
Councils (as shareholders)	✓	✓	✓	✓	✓
Bankers	✓	✓			
Connected customers	✓	✓	✓	✓	✓
Energy retailers	✓	✓	✓		
Mass-market representative groups	✓	✓	✓		✓
Industry representative groups	✓	✓	✓		✓
Staff & contractors	✓	✓		✓	✓
Suppliers of goods & services	✓	✓			
Public (as distinct from customers)			✓	✓	
Land owners				✓	✓
Councils (as regulators)			✓	✓	✓
Land Transport				✓	✓
Ministry of Economic Development		✓		✓	✓
Energy Safety Service				✓	✓
Commerce Commission	✓	✓	✓		✓
Electricity Commission					✓
Electricity Complaints Commission			✓		✓
Ministry of Consumer Affairs			✓		✓
Generators	✓	✓	✓		

Identifying, Managing and exceeding stakeholder expectations are core business goals for AEL. Table 2.3 below lists some of the information inputs and activities AEL uses to achieve this.

▪ *Table 2.3: Identification and Management of Stakeholder expectations*

Stakeholder	Identification & Compliance with expectations
Lines Trust South Canterbury	• By their approval or required amendment of the SCI • Regular meetings between the directors and the trustees
Councils (as shareholders)	• By their approval or required amendment of the SCI • Regular meetings between the directors and the trustees
Bankers	• Regular correspondence between the bankers and AEL • By adhering to AEL's treasury procedure

Stakeholder	Identification & Compliance with expectations
Connected customers	• Regular discussions with large industrial consumers as part of their on-going development needs • Response to media articles and sponsorship • Biannual customer surveys
Energy retailers	• Annual consultation with retailers
Mass-market representative groups	• Informal contact with group representatives
Industry representative groups	• Informal contact with group representatives
Staff & contractors	• Regular staff briefings • Regular contractor meetings
Suppliers of goods & services	• Regular supply meetings • Newsletters
Public (as distinct from customers)	• Informal talk • Media presentations/information disseminations • Local advertising & sponsorship • Feedback from the Trust's public meetings
Land owners	• Individual discussions as required • Safety notices
Councils (as regulators)	• Formally as necessary to discuss common issues (assets on Council land or CDEMG)
NZ Transport Agency	• Formally as required • Industry working groups
Ministry of Economic Development	• Regular bulletins on various matters • Release of discussion papers • Feedback through industry working groups • Analysis of submissions on discussion papers
Energy Safety Service	• Promulgated regulations and codes of practice • Audits of our own activities • Industry working groups • Audit reports from other lines businesses
Commerce Commission	• Regular bulletins on various matters • Release of consultation papers • Analysis of submissions on discussion papers • Conferences following submission process
Electricity Authority	• Weekly update through the Market Brief

Stakeholder	Identification & Compliance with expectations
	• Release of consultation papers • Briefing sessions • Analysis of submissions on discussion papers • Conferences following submission process • General website details
Electricity & Gas Complaints Commission	• Foundation member • Reviewing their decisions in regard to other lines companies • Quarterly reports
Generators	• Individual discussions as required

2.6.3 Accommodating Stakeholder Interests

The following table provides a broad indication of how AEL accommodates stakeholder interests:

▪ *Table 2.4: AEL Accommodating Stakeholder Interests*

Interest	Description	How AEL 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 in AEL (and to keep owning AEL).	• AEL will accommodate its stakeholders' needs for long-term viability by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return on employed capital. In general terms this will need to be at least as good as AEL's 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 signaling underlying costs. Getting prices wrong has economic implications for both AEL and its consumers.	• AEL's 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 AEL's 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 AEL 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

Interest	Description	How AEL accommodate interests
		distort a cost effective pricing methodology.
Supply quality	Emphasis on continuity, restoration and reducing flicker is essential to minimising interruptions or maintaining a reasonable supply quality to customers businesses.	• AEL will accommodate its stakeholders' needs for supply quality by focusing resources on continuity and restoration. Previous customer surveys conducted all reveal that continuity and restoration of supply are the supply attributes that customers value the most. • AEL will endeavour to comply with the quality standards under the default price-quality path during each regulatory year.
Safety	Staff, contractors and the public at large must be able to move around and work on our network in total safety.	• AEL 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. • AEL will ensure the safety of its 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 in regard to remaining within the road reserve and not encroaching on private property.
Compliance	AEL must comply with many statutory requirements ranging from safety to the annual disclosure of information.	• AEL will ensure that all safety issues are adequately documented and available for inspection by authorised agencies. • AEL will disclose information so as to comply with the information disclosure requirements.
Efficient operation	Operating the business and managing costs efficiently	• AEL plans to instigate a programme to significantly upgrade its 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.

2.6.4 Managing Conflicting Interests

Priorities for managing conflicting interests are:

- Safety—AEL will give top priority to safety. Even if it has to exceed budget or risk non-compliance, AEL will not compromise the safety of its staff, contractors or the public.
- Viability—AEL will give second priority to viability (as defined above), because without it AEL will cease to exist as an entity which makes supply quality and compliance pointless.
- Pricing—AEL will give third priority to pricing as a follow on from viability (noting that pricing is only one aspect of viability).

We recognise the need to appropriately fund our business to ensure that customers receive the quality of supply that they expect at a price that they are willing to pay.

- Supply quality—AEL will give fourth priority to supply quality as this is what makes AEL's consumers, and therefore AEL, successful.
- Compliance—AEL will give fifth priority to compliance that is not safety related.
- Efficient Operation—AEL will give sixth priority to efficient operation.

The Process for identifying and managing potential conflicting interests involves recognition and evaluation of the potentially conflicting matters by AEL's qualified and experienced managers and employees, with due regard to Acts, Regulations, policies, guides, standards, procedures, and other documents that govern AEL's day to day operations; and then taking actions that are appropriate, with due regard to relevant urgencies as may be determined in each case.

2.6.5 Climate Change

Climate Change is not a Stakeholder but its effects on the AEL Network may, or will, be of interest, even concern, to the Stakeholders. As time passes the effects of Climate Change will become more apparent and environmental changes such as sea level rise, more extreme weather and increases in vegetation growth that are already suspected will be confirmed.

The existence, causes, and effects of Global Climate Change have been studied, discussed and debated since the "greenhouse effect" was first postulated by Joseph Fourier in 1824.

While the "greenhouse effect" is an accepted scientific phenomenum, the role of human activities on the observed strengthening of the global greenhouse effect and its effect on Climate Change is still controversial.

Nevertheless, most scientific authorities accept that Climate Change is driven by the observed strengthening of the global greenhouse effect.

Refer to the latest Assessment Report from the United Nations' Intergovernmental Panel on Climate Change (IPCC).

Information relevant to the New Zealand situation may be obtained from the following web sites:

- www.mfe.govt.nz/publications/climate/
- www.niwa.co.nz/our-science/climate/

- www.climatechange.govt.nz/

2.6.5.1 Projected Changes in Weather

The Ministry for the Environment's (MFE) projections of future New Zealand Climate Change (www.mfe.govt.nz/publications/climate/climate-change-effect-impacts-assessments-may08/) contains the following 50 year projections for the Canterbury area from 1990 to 2040 (§2.2.1):

- Mean Temperature Increases in ˚C, average, (lower limit, upper limit):
  - Summer: 0.9, (0.1, 2.2);
  - Autumn: 0.9, (0.2, 2.2);
  - Winter: 1.0, (0.4, 2.0);
  - Spring: 0.8, (0.2, 1.8);
  - Annual: 0.9, (0.2, 1.9).

Rainfall Patterns (§2.2.2):

- Mean Ranfall changes in %, Tekapo Station:
  - Summer: 1%, (-16%, 16%);
  - Autumn: 2%, (-12%, 10%);
  - Winter: 8%, (-1%, 19%);
  - Spring: 6%, (-3%, 17%);
  - Annual: 4%, (0%, 13%).
- For a more coastal estimate, the projected mean rainfall % changes for the Christchurch Station may be of interest:
  - Summer: 2%, (-15%, 22%);
  - Autumn: 5%, (-10%, 30%);
  - Winter: -8%, (-30%, 7%);
  - Spring: -1%, (-8%, 9%);
  - Annual: -1%, (-10%, 9%).

The report (§2.2.4) notes that "warmer atmosphere can hold more moisture (about 8% more for every 1˚C increase in temperature), so there is an obvious potential for heavier extreme rainfall under global warming. The IPCC, in its Fourth Assessment Report (2007), declared that more intense rainfall events are “very likely over most areas”. The mountainous nature of New Zealand, with its starkly contrasting rainfall climates, makes it difficult to be sure if this situation is universally applicable across the country. Any change in the mix of circulation patterns will have a major impact on the spatial distribution of precipitation”

The Report goes on to comment that in contrast with an earlier study in 1996 “More recent climate model simulations confirm the likelihood that heavy rainfall events will become more frequent.”

The Report (§2.2.5) has the following comments regarding snowfall and snowline: “It is generally expected that snow cover will decrease and snowlines rise as the climate warms. However, there are confounding issues. As stated” above “warmer air holds more moisture, and during winter this moisture could be precipitated as snow at high elevations. There could also be instances of increased winter snowfall to low elevations, for the same reason. However, with expected increase in temperature, any snow cover will melt more quickly, and thus the duration of seasonal snow lying on the ground is expected to be shortened”.

Analyses of the effects of changes in rainfall and snowfall on seasonal river discharge and flood magnitude have yet to be completed and reported for NZ.

Sea level rise is another effect of Climate Change. MFE state in their Report (§2.2.6) that “the rise of sea level around New Zealand is likely to be similar to the global projections of sea-level rise by the IPCC Fourth Assessment, 2007. This statement is based on the similarities between the New Zealand average and the global average over last century of around 1.8 mm/year. Sea-level rise will continue for several centuries even if greenhouse gas emissions are reduced”.

The MFE Report goes on to state that: “the IPCC projects that the mean sea level will rise by at least 18-59 cm by the 2090s (2090-2099 average) from the 1990s (1980-1999 average), taking the full range of SRES scenarios into account. A further 10-20 cm rise above current levels would occur if melt rates of Greenland and Antarctica were to increase…The IPCC notes that even larger sea-level rises cannot be excluded, …”.

The Report (§2.2.7) discussed changes in wind patterns, including changes in mean strength and direction.

The Report (§2.2.8) also discusses “ex-tropical cyclones” and “extra-tropical cyclones” but apart from a possible increase in peak wind speeds and likely increases in extreme precipitation, the Report is not able to be more specific about possible effects for New Zealand.

The Report (§2.2.8) discusses the effect of Climate Change on ocean currents and wave patterns. There appears to be uncertainty over the long term effects, except that the increased prevailing westerlies predicted may increase the frequency of heavy swells that would add to effects of higher sea levels.

The latest news from NIWA's web site includes:

- New four year programme of study by NIWA and Landcare Research of NZ of climate change predictions and its impacts over the next 90 years (3/10/2012);
- New study measures snowmelt into South island rivers (27/11/2012)

2.6.5.2 The effects of climate changes on the AEL Network Assets

There are a number of ways that climate change may affect the AEL Network Assets:

- Changes in maximum demand and in seasonal and regional load patterns;
- Changes in energy consumption;
- Changes in accessibility of existing lines and new line sites for maintenance and construction;
- Increased risk of damage to line 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 interference of vegetation on the line assets and the management of the vegetation;
- Increased risk of damage to network assets located in or near waterways that may change their flood patterns;
- Possible changes in the habits and patterns of birds and other wildlife that may affect the security of network assets (large birds causing line clashes, insulation damage from birds and oppussums, etc.);
- Sea level changes may affect AEL's Network Assets where these are located on low lying coastal land that may be subject to sea erosion or flooding.

2.7 Accountabilities for Asset Management

AEL's accountabilities and accountability mechanisms are shown in Figure 2.2 and discussed in detail in the following sections.

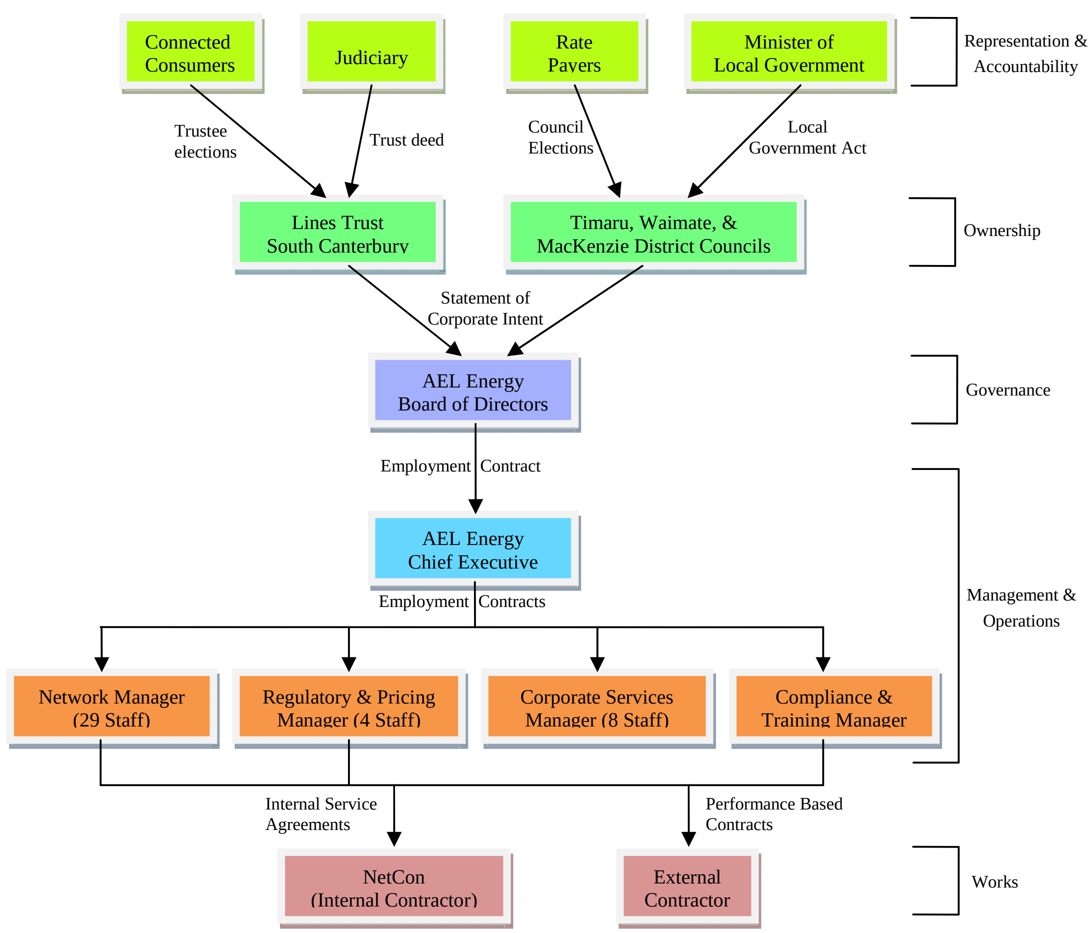
2.7.1 Accountability at Ownership Level

AEL has four shareholders – a Trust and 3 District Councils:

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

The Trust is subject to the following two accountability mechanisms:

- an election process
- the Trust Deed which holds all Trustees collectively accountable to the New Zealand judiciary for compliance with the Deed



- *Figure 2.2: Accountabilities for Asset Management*

The three Council's are ultimately accountable to their ratepayers (most of whom are also AEL consumers) 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 AEL's constitution that *inter alia* restricts the sale of AEL shares and determines how AEL's directors will be appointed.

2.7.2 Accountability at Governance Level

AEL's 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 tradeoffs. AEL currently has five director's 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.

2.7.3 Accountability at Executive Level

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

2.7.4 Accountability at Management Level

Accountability for asset management at the second tier is split 4 ways:

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.

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.

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.

The Operations Manager, Asset Manager and the Senior Electrical Engineer report to the **Network 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.

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.

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 and performance of existing assets and their lifecycles. 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 Chief Executive Officer through their respective employment contracts which sets out performance targets based around business goals of meeting budgets and reliability standards.

2.7.5 Accountability at Operational Level

The Asset Manager, Network Manager and Operations Manager all have engineering staff that are accountable to them primarily through employment contracts for delivering specific outcomes that contribute to the efficient management of assets and customer service.

2.7.6 Accountability at Works Implementation Level

NetCon, a subsidiary wholly owned by AEL is accountable to AEL through an internal service level agreement. External contractors are accountable to the AEL through performance based contracts.

2.7.6.1 NetCon Limited

NetCon Limited (NetCon) is the preferred network contractor for capital and maintenance services in the South Canterbury area. NetCon is an associate company, wholly owned by AEL.

NetCon Ltd has approximately 70 staff that are able to provide a scalable resource for AEL during adverse weather events or large projects via relationships AEL has under Mutual Aid Agreements with other networks.

2.7.7 Key Reporting Lines

The Directors govern (as distinct from manage) AEL's lines business. The Board has delegated overall responsibility for the management of the line assets to AEL's Chief Executive Officer (CEO).

The AEL 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. 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 (Board) 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.

2.7.8 AEL Operating Structure

2.7.8.1 Location

AEL's operations base is located at 33 Meadows Rd, Washdyke, Timaru. The site is also the base for NetCon, the preferred network contractor. In addition to the main depot in Timaru, AEL operates one remote depot in Tekapo. This remote depot forms the base for the contractor for Operations Group work.

2.7.8.2 Network Group

The Network group consists of the Operations Group, the Asset Group, the Engineering Group, and the Process & Standards Group.

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 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..

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

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; and

- 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.

2.7.8.3 Corporate Services Group

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

2.7.8.4 Regulatory and Pricing Group

The Regulatory and Pricing group ensures that AEL is aware of and meets its regulatory obligations in accordance with the various legislative instruments under which it operates, and manages the billing and registry functions. The Group also provides commercial and business analysis and expertise support.

2.7.8.5 Compliance and Training Manager

The Compliance and Training Manager manages compliance and training matters, and champions AEL's Health & Safety culture through promotion of best practice and continuous improvement of safety on the Network. The manager is also responsible for ensuring that our major contractor (NetCon), or any other people working on the Network, are authorised to access the network and complete their work to the required standards. Human resources functions are predominantly managed by the Compliance and Training Manager

2.7.8.6 Service Contract Negotiations

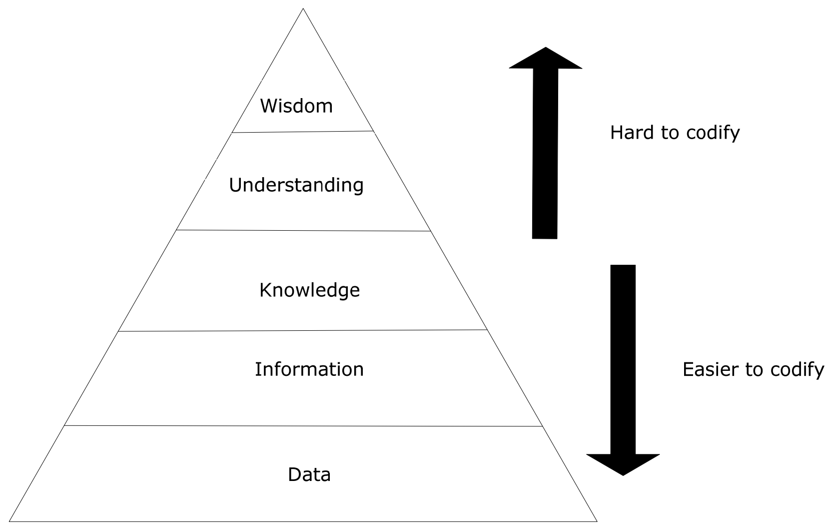
AEL's policy is to use NetCon for the majority of the Network's operations, maintenance, renewal and upgrade work. All work is subject to a Service Level Agreement which is negotiated between AEL and NetCon each year.

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.

2.8 Asset Management Systems and Processes

The core of the asset management activities lie with the detailed processes and systems that reflect our thinking, manifest in our policies, strategies and processes and ultimately shape the nature and configuration of our fixed assets. The hierarchy of data model shown in Figure 2.3 describes the typical types of information residing within the business.



- *Figure 2.3: Data Hierarchy*

The bottom two layers of the hierarchy tend to relate strongly to asset and operational data which mostly reside in: (a) the various electronic and paper databases, and GIS system; and (b) the SCADA System, respectively; and also in the summaries of this data that form one part of our decision making.

The third layer – knowledge – tends to be more broad and general in nature and may include such things as technical standards that codify accumulated knowledge into a single useful document.

The top two layers tend to be very broad and often undefined. It is at this level that key organisational strategies and processes reside. As indicated in Figure 2.3, it is generally hard to quantify these elements, hence correct application is heavily dependent on skilled people.

2.8.1 Asset Knowledge

Ongoing effort is directed at altering business systems to ensure the design and planning work is supported through the GIS system as well as updating of existing information to reflect the current network status and configuration. This should prove more efficient than maintaining the many variations of hard copy systems that exists once an “off the shelf” GIS replaces the current in-house developed system.

Various other data bases are used to interact with the GIS system and these were intended to be linked and updated as asset data from field capture improves over time. However, some of these electronic and paper databases are legacy systems or manual systems (such as spread sheets) which need to be replaced with an integrated database system.

2.8.2 Improving Asset Knowledge Quality

The field capture of AEL's overhead distribution system has improved the quality of the asset data as well as the unique pole identification system which allows field staff to reference a number from the field back to the electronic record.

The asset condition information remains a key area for improvement. Once unlocked it will release value to the business by improving asset decision making. Significant progress has been made over the last couple of years with condition assessments being conducted on all distribution boxes and distribution transformer installations. There is already a significant knowledge base around pole conditions.

With GIS software, asset condition information and maintenance requirements can be prioritized and scheduled to allow better asset planning. Keeping records in separate databases or recording condition assessments on hard copy format is inefficient. GIS software and application development now allows electronic field data capture to be processed on the move and update records seamlessly.

AEL will be better placed in asset planning once systems are developed to take advantage of further data handling efficiencies to make better informed decisions regarding asset condition rather than the historical approach of using age as an initial indicator.

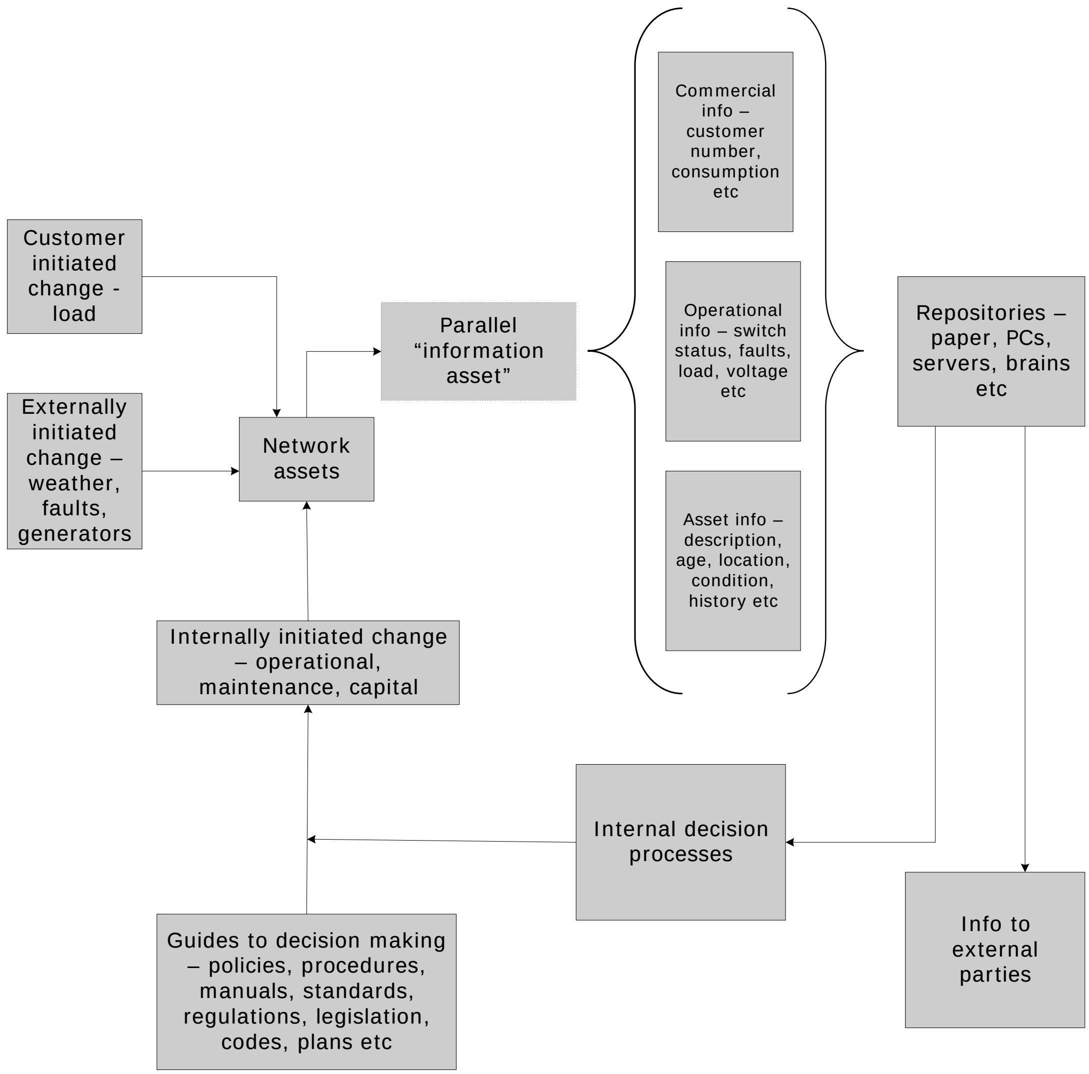
Further developments in moving to new communication mediums between substations will also improve the degree of data which can be accessed and hence how the system is operating in real time, rather than reactively once an event has occurred.

2.8.4 Guides to Decision Making

Accurate decision making requires the convergence of information and knowledge, understanding and wisdom to find an acceptable answer – deficiencies in either area (incorrect data, or a failure to correctly understand issues) will lead to wrong outcomes. However these two aspects (information and knowledge, understanding and wisdom) are fundamentally different and have the following characteristics:

- Data and aggregated data (which are called information) tend to be specific to individual assets or groups of assets. It tends to be recorded in an absolute form.
- Knowledge, understanding and wisdom tend to be more process and system related. They tend to be experiential rather than recorded in an absolute form and also tend to be undefined. Examples range from the best way to erect a pole in sandy soil to understanding how the life of a transformer might be shortened by overloading – these tend to be the result of experience and tend to become part of the company's collective behaviour rather than a simple store of hard information.

The source, roles and interaction of each component of the hierarchy are shown below in Figure°2.4.



- *Figure 2.4: Key Information Systems & Processes*

The decision tools used to evaluate options of increasing cost are described in Section 5.2.3.

2.8.5 Key Systems & Processes

AEL’s key processes and systems are based around the key lifecycle activities defined in Figure 6.1 and are described in the following sections:

2.8.5.1 Operating Processes & 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 AEL's internal operating procedures and sharing of knowledge with other network companies on safe working practices and network control and operating procedures.

2.8.5.2 Maintenance Processes & Systems

Maintenance processes are based initially 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 a follow up inspection at the next recommended inspection interval.

The present maintenance systems are generally manual and paper based, with the assistance of Nimbus (a project, job and order creation and invoice payment) accounting system, Gentrack (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 AEL's current practices.

The routine maintenance is undertaken largely by AEL's prime contractor, NetCon with the assistance of detailed planning maintenance schedules for the AEL substations and plant. These schedules are held, maintained and operated within spread sheets by the prime contractor, NetCon.

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

In 2011, AEL 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 chargable jobs, and CAPEX project jobs, the Nimbus system is used for the AEL 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.

2.8.5.3 Renewal Processes & 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 commonly undertaken and 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 undertaken either by NetCon within their routine maintenance programme, or from specific condition assessment inspections ordered for specific types of plant by AEL's Asset Group, or by unscheduled inspections by AEL engineering staff, may all generate information that is collated manually, reviewed and assessed by AEL, and may result in planning decisions by AEL Network and Asset Groups to initiate a project within the AMP for the refurbishment or renewal of the asset in question.

2.8.5.4 Up-Sizing or Extension Processes & 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.

2.8.5.5 Reliability Enhancement Processes & 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 the AEL 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.

2.8.5.6 OHUG Processes & 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 placing 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.

2.8.5.7 Retirement Processes & 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 basic insulation levels being exceeded, requiring replacement of the asset for safety reasons.

2.8.5.8 Wider Business Processes & Systems

Customer applications for connection to the AEL 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 to small to medium enterprises.

The replacement system proposed by the present IT Reviewis 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.

3.

Assets Covered

3.1 Distribution Area

This section summarises AEL's assets and asset configurations, but begins by describing AEL's geographic coverage and the issues that are driving key asset parameters such as load growth that are seriously affecting AEL's capacity to supply future load.

3.1.1 Geographical Coverage

AEL's network stretches over 10,000 sq km, 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 below. Three District Councils, namely Timaru, Waimate and Mackenzie, provide infrastructure assets across the area and are also stakeholders in AEL. (The exception to the above is the Hakataramea Valley and the associated high country to the west bounding on the Aviemore and Benmore lakes which are part of the Network Waitaki supply area).

The majority of consumers live in Timaru City situated on the East Coast, with about 13,500 of AEL's 30,576 consumers living in or near the Timaru area.

Timaru is the hub of South Canterbury connecting the road networks West, North and South. The city serves a 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 for new industrial development.

The second largest population group lives at Temuka, 20 km North of Timaru. This area is surrounded by rural plains. AEL's largest customer, Fonterra (30 MW instantaneous maximum demand) operates a milk processing factory at Clandeboye and continue 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, Pareora and St Andrews, are rural support towns with stable populations that are serviced by the Timaru District Council.

▪ ***Figure 3.1: AEL Area of Supply***

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 establishment of a timber mill and an independent milk processing plant represents the larger loads in the area and have stimulated local growth, particularly with the distributed irrigation activity and dairy loads which are driving high electricity demand. The geography of this area is balanced between rolling hills and flat plains, with planning being considered for establishing a large irrigation project and power station on the north bank of the Waitaki River from 2014, and a dairy factory at Glenavy.

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. Growth in the Tekapo and Twizel destinations are predicted to increase, particularly in Twizel with plans for further irrigation development in the district.

The load growth throughout the AEL supply area has slowed, and plateaued in some areas, following the international credit crises in 2009.

3.1.2 Demographics

AEL's network area corresponds almost exactly to the combined coverage of the Timaru, Mackenzie and Waimate District Councils. The population figures for the network area for 1996, 2001, and 2006 are listed in Table 3.1 below.

- ***Table 3.1: Population growth***

District	1996 census	2001 census	2006 census
Timaru	42,633	41,967	42,870
Mackenzie	4,077	3,717	3,804
Waimate	7,620	7,101	7,206
Total	**54,330**	**52,785**	**53,880**

(Note: due to the Christchurch Earthquakes, the 2010 census did not take place).

Within the base population there are three important elements that influence AEL's business strategy namely:

- The median age of the population (how many people will move from market-driven incomes to fixed incomes over the next 20 years or so).
- The median household income (a reflection of the general level of wealth and economic activity which drives discretionary spending).
- The level of unemployment (which also provides a measure of the discretionary income potential).

These elements are detailed in Table 3.2 below:

- ***Table 3.2: Population elements influencing AEL's business strategy***

District	Median age	Percent population over 45	Median personal income	Unemployment
Timaru	42	44%	$21,500	6.3%
Mackenzie	39	41%	$23,000	3%
Waimate	41.4	46%	$18,000	4.4%
National average	**34.8**	**32%**	**$20,700**	**7.5%**

Table 3.2 on the previous page, indicates that the median age and personal income within AEL's is higher than the national median, and the level of unemployment is lower than the national average rate.

3.1.3 Key Economic Activities

The South Canterbury area's key economic activities are primary product based, including recent significant growth in arable, dairy farming and dairy processing. The port operations are also an important element in the local economy. The area's fortunes will therefore be strongly influenced by:

- The relative value of dairy products compared to other commodities that drive the rate of dairy conversions.
- Government policy on nitrogen-based pastoral farming.
- Environment Canterbury's policies on access to water for dairy/crop farming and investment in further irrigation scheme development.
- Major shipping lines decisions on which New Zealand ports their ships will visit.
- Use of rail for transport of containers to other shipping line serviced ports.
- It is expected that the proposed Holcim Weston cement plant, near Oamaru, will rail cement to PrimePort Timaru for coastal shipping and exporting.
- Christchurch earthquakes in 2010 & 2011 may influence the population growth of the district and increase Timaru Port activities

The impact of these issues is detailed in Table 3.3 below:

Table 3.3: Economic Activities and their impact

Economic Activity	Impact
Rate of dairy conversions	• May lead to increased dairy shed demand. • May lead to increased dairy processing demand.
Government policy on nitrogen-based farming	• May lead to contraction of dairy shed demand. • May lead to contraction of dairy processing demand.
Access to water	• May lead to increased irrigation demand. • Shift of electrical load centre will drive new infrastructure development
Shipping line decisions	• Mayhave reduced demand at Port of Timaru. • May influence reliability requirements for cold storage at Port of Timaru.
Container handling for railing to another port	• May increase demand at rail yards • May influence reliability requirements for cold storage
Loading out of cement at PrimePort	• May lead to a 1.5MW demand increase.
Christchurch earthquake	• May increase consumer load and Port of Timaru demand

3.1.4 Large Consumers

The impact that these large customers have on AEL's networks is described below:

3.1.4.1 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 2 x 20 MVA zone substation, including OLTC transformers and 15 x CB 11 kV switchboard, plus - several 11/0.4 kV distribution substations with transformers and RMUs.
Impact on AEL Network:	Considerable.

3.1.4.2 Fonterra Co-Operative Group Limited

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 2 x 25 MVA zone substation, including OLTC transformers and 12 x CB 11 kV switchboard, plus several 11/0.4 kV distribution substations with transformers and RMUs.
Impact on AEL Network:	Considerable.

3.1.4.3 Silver Fern Farms

Location:	Pareora
Dedicated Assets:	N-1 33/11 kV zone substation with upgrading 2 x 9/15 MVA capacity transformers and two re-locatable 33 kV switch-rooms; with two existing dedicated 11 kV CB feeders to consumer owned switchgear at works,
Impact on AEL Network:	Significant, with growing irrigation load in the Pareora area and provision needed to back up the supply to the south of Timaru; however the ability to relocate the 33/11 kV transformers and the new 33 kV switchboards to another location within the growing AEL Network would minimise the effect of possible stranded assets.

3.1.4.4 Alliance Smithfield

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

3.1.4.5 Fonterra Co-Operative Group Limited

Location:	Studholme
Dedicated Assets:	- 7 x 11/0.4 kV distribution transformers, - one dedicated 11 kV 630 Amp CB and feeder from AEL switch-room at Studholme GXP
Impact on AEL Network:	Significant, but transformers and switchgear could be reused over time elsewhere in the Network.

3.1.4.6 Fonterra Co-Operative Group Limited

Location:	Studholme
Dedicated Assets:	- 13 x 11 kV RMUs, - one dedicated 11 kV 630 Amp CB and feeder from AEL switch-room at Studholme GXP
Impact on AEL Network:	Significant, but transformers and switchgear could be reused over time elsewhere in the Network.

3.1.4.7 Juice Products New Zealand

Location:	Washdyke
Dedicated Assets:	- one 1 MVA transformer, - 95 meters of 95mm^2 11 kV cable
Impact on AEL Network:	Significant load but limited impact with respect to network.

3.1.5 Other Drivers of Electricity Use

Other drivers of electricity use include:

- Cold weather in winter (coastal South Island compared with North Island)
- Low inland temperatures during winter (-10^{o}C frosts are common in most areas west of Fairlie and Geraldine).
- Moves by Environment Canterbury to improve air quality by restricting the use of coal and wood fires by replacement with clean air approved units or replacement with electric heat pumps. AEL recognises that installing even 3,000 heat pumps rated at 2kW each would add 6MW of winter peak demand. However this projected load could be less if some older inefficient types of electric heating were updated.

- The likely use of these heat pumps as air conditioners in the 30°C summer heat adding further to the summer peak.

The existing weather related drivers may be further influenced by climate change within the 10 year planning period (refer to Section 2.6.5).

3.1.6 Energy & Demand Characteristics

Key energy & demand figures for AEL's seven GXP areas for the year ending 31 March 2012 are detailed in Table 3.5 below.

Table 3.5: GXP Energy and Maximum Demand figures

GXP area	Parameters				
	Energy (GWh)	Max Demand (MW)	Load Factor (F=W/(Pmax.T))	Txpr Capacity Utilisation (Pmax/Ptxfr)	Long-term trend (based on 15 year historic)
Albury	10.41	3.92	0.30	78%	1.35 % growth
Bells pond	17.06	6.07	0.32	30%	5.89 % growth
Studholme	55.41	10.88	0.58	49%	7.72 % growth
Tekapo	16.33	3.87	0.48	39%	3.46 % growth
Temuka	253.98	49.20	0.59	48%	4.77 % growth
Timaru	332.97	61.04	0.62	74%	0.83 % growth
Twizel	12.14	2.87	0.48	7%	2.54 % growth
Exported	-14.73				
Generation	24.78				
Total	**708.34**	**116.1**			**3.07 % growth**

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

Inspection of the Timaru and Timuka GXP MD trends appear to show that the MDs for these two GXPs have plateaued over the last five years.

Forecast growth in demand has max demand increasing to 120 Mw in 2012/13 year 143 MW in 2017/18. More information on our demand forecasts can be found at Schedule 12c: Demand Forecast at Appendix I.

3.2 Network Configuration

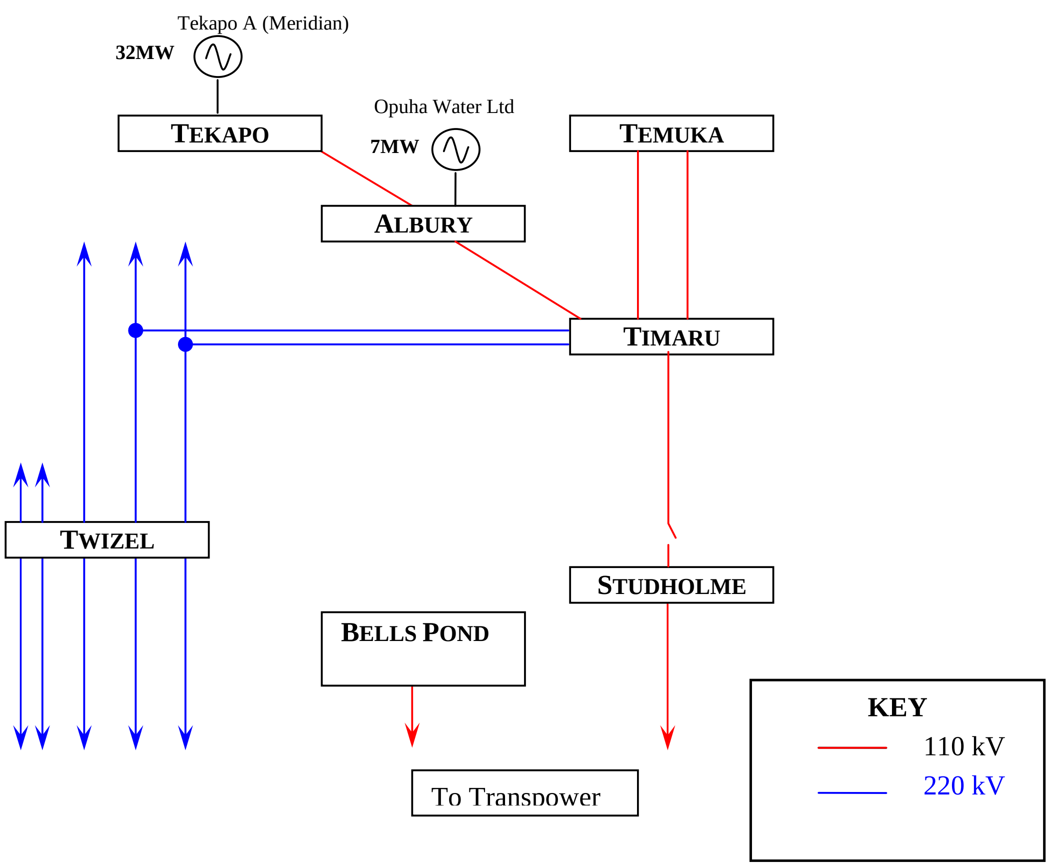
AEL's network comprises two historically distinct lines businesses, the Timaru MED and the South Canterbury EPB, which were merged in 1993. Hence the existing asset configuration comprises lines through a corridor in an EPB area to supply a totally encircled MED area similar to cities such as Invercargill, 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 (e.g. upgrading of 11 kV lines and cables and introduction of additional, or upgraded, points of connection between the two networks.

3.2.1 Bulk Supply Configuration

The configuration of the GXPs from a transmission perspective is detailed in the following diagram.

- *Figure 3.2: Transpower GXP's*



AEL currently takes bulk supply from seven Transpower GXPs with details as listed at Table 3.6 over page.

Table 3.6: GXP Supply Details

Transpower GXP	GXP voltage(s), Transmission	GXP supply Voltage to AEL	GXP (n) Capacity	GXP (n-1) Capacity	AEL Demand
Albury	110 kV	11 kV	5 MVA	0	3.9 MW
Studholme	110 kV	11 kV	22 MVA	11 MVA	10.9 MW
Bells Pond	110 kV	110 kV	20 MVA	0	6.1 MW
Tekapo	110 kV	33 kV	10 MVA	0	3.9 MW
Temuka	110 kV	33 kV	120 MVA	60 MVA*	49.2 MW
Timaru (city 11 kV & 11/33 step up)	220 kV, 110 kV	11 kV	82 MVA	54 MVA	61.0 MW
Twizel	220 kV	33 kV	40 MVA	20 MVA	2.9 MW

(Based on statistics year ending 31st March 2012).
(The Transpower GXP 110/33 kV transformers were uprated from 51 MVA to 60 MVA in 2010).*

The ownership and management of these seven GXPs are Transpower's responsibility. The key GXP development issues that AEL is currently discussing with Transpower are listed in paragraph 5.3.3.10.

3.2.2 Transpower – Grid Exit Points

The seven Transpower GXPs are described in more detail below in order of magnitude of load supplied.

3.2.2.1 Timaru GXP

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 Sub supplying a 5 MW meat works and a rural load, and the third circuit supplying a rural community at Pleasant Point Zone Substation for township and rural customers some 12 km away.

Four 11 kV sub-transmission cables supply some 35 MW to the CBD area through Grasmere St 11°kV switching substation, then cables onto Hunt St and North St 11 kV switching stations. Each switching station has an indoor switchboard with between eight and 12 cable feeders each, supplying into the CBD 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. Transpower is also considering replacing the 110/11 kV transformers T2 and T3. The transformers are aged single-phase banks which may be replaced with three-phase units.

As AEL's 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.

3.2.2.2 Temuka GXP

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 Alpine's 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 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.

3.2.2.3 Studholme GXP

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 recently acquired Studholme dairy factory, and the surrounding rural areas. The substation demand is summer peaking from strong growth from Fonterra's Studholme 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.

Alpine is working 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.

3.2.2.4 Bell's Pond GXP

Bell's Pond GXP is a single tee off the STU-OAM-WTK 2 110 kV circuit. The GXP is basically a 110 kV metering point which was made available to Alpine so that a 110/33/11 kV zone substation could be connected.

Long term, as the load grows in the lower Waitaki valley, a second tee off is intended to be made off the OAM- BPT-WTK 1 110 kV circuit for a second transformer thus increasing the station security to full N-1. This is currently being discussed with Transpower.

3.2.2.5 Albury GXP

Albury is teed off the TIM-TKA 110 kV line and has a single 110/11 kV bank connected onto a new 11 kV switchboard via one incomer. This new switchboard was commissioned in 2011 to replace the previous switchboard that had reached end of life. The new switchboard has three 11°kV feeders. One 11 kV feeder, Fairlie, is transformed via an AEL 11/33 kV step-up transformer. Either one of the other two feeders may be switched by AEL to replace the usual Fairlie feeder when it needs to be released for maintenance or for other reasons. The 33 kV supply from the 11/33 kV 7 MVA step-up is taken to Fairlie and then onto Opuha Dam. This allows connection of the Opuha 7 MW hydro generation with Albury, and export to the Grid. The remaining two 11 kV feeders supply rural farming areas with one feeder being able to be parallelled with the Pleasant Point Zone substation.

3.2.2.6 Tekapo GXP

Tekapo A is connected to the grid via a 110/11kV transformer. Genesis (previously Meridian owned) can make their generator available if the grid is unavailable. Generally when the Tekapo A-Timaru circuit is released, Genesis can run their generation to supply AEL's 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 11/33kV step up transformer and a 33kV circuit breaker (CB1042) to supply AEL's short 33 kV overhead line to the Tekapo Village 33/11 kV zone substation. There is no alternative supply should this fail or be released.

A study was commissioned to replace the 11 kV board at Tekapo A, by Meridian and Transpower. This would have given opportunity to add a bus coupler and an additional 11 kV Alpine feeder to the board. The bus coupler would segregate the generator and 110/11 kV incomer and the two Alpine feeders. The 33 kV line to the Tekapo Village 33/11 kV Zone substation would then be decommissioned and two 11 kV feeders utilised instead. This would increase Alpine's security of supply to Tekapo Village.

With the change of ownership of Tekapo A from Meridian to Genesis, AEL is unsure of the project's future.

3.2.2.7 Twizel GXP

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 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.

3.2.3 Assets by Category

AEL's assets, from the Transpower GXPs down, 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, & North Streets),
- Distribution Lines and Cables—11 kV (and some 22 kV),
- Distribution Substations—including Transformers and RMUs, Reclosers, Line Regulators, Capacitors, and Rural Switches: 11/0.4 kV transformers & 11 kV switches, regulators, etc. (and some 22 kV),
- LV Reticulation Lines and Cables—including Link and Distribution Boxes: 400 V,
- SCADA, Communications, and Ripple Plants
- Meters and Load Control Relays at consumer premises,
- Emergency mobile diesel generator for use during faults or shutdowns: 1 x 400 V, 275 kVA (additional generators are hired from time to time).

3.2.4 Sub-Transmission & Zone Substation Configuration

Due to the legacy MED / SCEPB configuration, AEL has different sub-transmission asset configurations at each GXP, as summarized in Table 3.7 over page.

Table 3.7: GXP Configurations

GXP	Sub-transmission & 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 link line to the privately owned Opuha Power Station. • Two 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
Bells Pond	• AEL 110/33/11 kV zone substation with three 11 kV feeders
Tekapo	• Single 33 kV circuit to 33/11 kV Tekapo zone substation with four 11 kV feeders, and tap-off 33 kV line to Glentanner, Unwin Hut and other smaller 33/11 kV zone substations.
Temuka	• Four 33 kV 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 feeders to the local 33/11 kV Temuka zone substation with six 11 kV feeders. • One 33 kV feeder to Geraldine. • One 33 kV feeder to Rangitata. • One 33 kV feeder 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 single circuit 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 3.8 below provides a breakdown of the current and forecast capacity and utilisation for each of our substations, and current distribution transformer capacity. More detailed information can be found at Schedule 12b: Report on forecast capacity at Appendix I.

Table 3.8: Substation Major Assets – Timaru GXP

Extract from Report of Forecast Capacity				
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	6.07	0.00	N	3.5
Clandeboye 1	13.00	20.00	N-1	0

Extract from Report of Forecast Capacity				
Existing Zone Substation	**Current Peak Load (MVA)**	**Installed Firm Capacity (MVA)**	**Security of Supply Classification (type)**	**Transfer Capacity (MVA)**
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	10.38	11.00	N-1	3.5
Tekapo Village	2.68	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

3.2.4.1 Substation Major Assets supplied from Timaru GXP

Table 3.9 below, details the major assets at all the substations supplied form Timaru GXP with respect to number, rating and general condition. The maximum demand at the various substations is also provided.

- *Table 3.9: Substation Major Assets – Timaru GXP*

Major AEL Sub-transmission & Substation Components Timaru GXP (Plant/Age/Condition)				
Sub-transmission from Timaru GXP	**Plant/Substation (Max Demand)**	**Transformers**	**Switchgear**	**Ripple Plant**
2x11 kV Cables (2004) Excellent	Grants Hill (11MW)	2x25 MVA OLTC 33/11 kV (2003) Excellent	3x33 kV OCBs (1986) Fair	Zellweger 317Hz
4x11 kV Cables (1983) Fair	Grasmere St (13+11+11 MW)		20xVCBs ((2012) Excellent	
2x11 kV Cables	North St		20xVCBs	

Major AEL Sub-transmission & Substation Components Timaru GXP (Plant/Age/Condition)				
Sub-transmission from Timaru GXP	**Plant/Substation (Max Demand)**	**Transformers**	**Switchgear**	**Ripple Plant**
(1962) Fair	(11 MW)		(2011) Excellent	
2x11 kV Cables (1987) Good	Hunt St (11 MW)		16xVCBs (1984) Good	
1x33 kV line (1977) Good	Pleasant Point (4 MW)	1x5-6.25 MVA (1972) Good	6x11 kV VCB (2006) Excellent 1x33 kV OCB (1980) Good	
2x33 kV Line (1979-85) Good (1963) Poor	Pareora (7 MW)	2x9-15 MVA OLTC 33/11 kV (2011) Excellent	6x33 kV VCBs (2011) Excellent 9x11 kV VCBs(2008) Excellent *	

The following diagram summarises the breakdown of AEL substations and sub-transmission assets connected from the Timaru GXP:

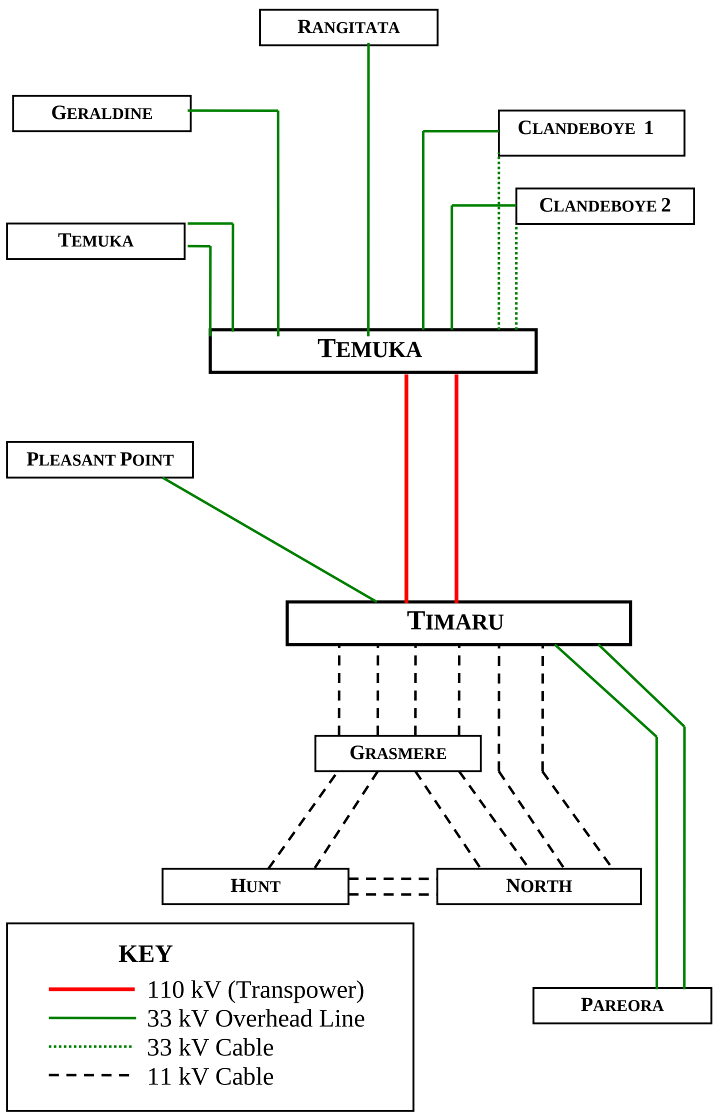


Figure 3.3: AEL Substations from Timaru GXP

The age, condition and details of the sub-transmission and substation equipment downstream of each GXP are summarised in the following tables:

- *Table 3.10: Substation Major Assets – Albury GXP*

Major AEL Subtransmission & Substation Components Albury GXP (Plant/Age/Condition)				
Subtransmission from Albury GXP	**Plant/Substation**	**Transformers**	**Switchgear**	**Ripple Plant**
1x33 kV Line (1967) Fair	Fairlie (3 MW)	1x3 MVA (1964) Fair	1x11 kV OCB (1989) Fair 1x33 kV OCB (1997) Good 1x2 MW Regulator (C435) Good, insufficient capacity	
1x11 kV Cable (2011) Excellent	Albury (6 MW)	7.5 MVA (1997) OLTC 33/11 kV Excellent	1x33 kV OCB (1994) Fair	1xPlessey-MetVic 605/510 Hz

- ***Table 3.11: Substation Major Assets – Temuka GXP***

Major AEL Subtransmission & Substation Components Temuka GXP (Plant/Age/Condition)				
Subtransmission from Temuka GXP	**Plant/Substation**	**Transformers**	**Switchgear**	**Ripple Plant**
Transpower 2x33 kV Cables	Temuka (17 MW)	2x25 MVA OLTC 33/11 kV (2007) Good	9x11 kV VCBs (2006) Excellent	1xZellweger 317Hz
1x33 kV Line (1966) Fair	Geraldine (6 MW)	1x5-9 MVA OLTC 33/11 kV (1980) Good	3x11 kV VCBs, feeders (2007) Excellent 1x11 kV VCB, T2 (2007) Excellent 1x33 kV VCB, T2 (2009) Excellent	
2x33 kV Line (2003, 2012) Excellent	Rangitata (8.5 MW)	2x9-15 MVA OLTC 33/11 kV (2011, 2012) Excellent	2x33 kV GCB (2011, 2012) Excellent 10x11 kV VCB (2004, 2011) Excellent	
2x33 kV Lines (1997) Good	Clandeboye1 (14 MW)	2x20 MVA OLTC 33/11 kV (1997) Good	2x33 kV OCBs (2004) Good 15x11 kV VCBs (2000) Excellent	
2x33 kV Cables (2004) Excellent	Clandeboye2 (14 MW)	2x25 MVA OLTC 33/11 kV (2004) Excellent	2x33 kV OCBs (2004) Excellent 12x11 kV VCBs (2004) Excellent	

- *Table 3.12: Substation Major Assets – Twizel GXP*

Major AEL Subtransmission & Substation Components Twizel GXP (Plant/Age/Condition)				
Subtransmission from Twizel GXP	**Plant/Substation**	**Transformers**	**Switchgear**	**Ripple Plant**
1x33 kV Line (1970) Good	Twizel (2.6MW)	1x5/6.25 MVA T1 OLTC (1972) Good 1x3 MVA (1964) Fair (off line spare)	8x11 kV OCBs (1971, needs update – '71 is when SCEPB took the MV OCBs over) Fair 1x33 kV OCB (1972, needs update – '72 is when SCEPB took the MV OCBs over – same vintage as TEK) Fair	

- *Table 3.13: Substation Major Assets – Tekapo GXP*

Major AEL Sub-transmission & Substation Components Tekapo GXP (Plant/Age/Condition)				
Subtransmission from Tekapo GXP	**Plant/Substation**	**Transformers**	**Switchgear**	**Ripple Plant**
1x33 kV Line (1991) Good	Tekapo (3.4MW)	1x3 MVA (1964) Fair	1x33 kV OCB (1984) Good, 1x33 kV OCB (1960) Poor 7x11 kV OCBs (1984) Good	Zellweger 500Hz
1x33 kV Line (1974) Good	Mount Cook (1MW)	1x1.5 MVA OLTC 33/11 kV (1974) Good	2x11 kV OCBs (1977) Fair 1x33 kV OCB (1974) Fair	
1x33 kV Line (1973) Fair	Glentanner (0.2MW)	600 kVA 33/11 kV (1986) Fair	1x11 kV OCB (1992) Good	

- *Table 3.14: Substation Major Assets – Studholme GXP*

Major AEL Subtransmission & Substation Components Studholme GXP (Plant/Age/Condition)				
Subtransmission from Studholme GXP	**Plant/Substation**	**Transformers**	**Switchgear**	**Ripple Plant**
Transpower 2x11 kV Cables	Studholme (16.5 MW)		9x11 kV VCB (2005) Excellent	Zellweger 317 Hz

The sub-transmission circuits to zone substations feeding the major loads of Timaru City and Clandeboye have N-1 capacity.

Reviewing each sub-transmission table indicates loading condition and age characteristics which require management within the term of this plan.

In Timaru City, Alpine's 11 kV distribution feeders are all ring feeds allowing N-1 supply with limited time for switching the feed direction and open point. The reticulation for Timaru City's Hunt St 11 kV switching station is shown in Appendix F. Appendix G details the LV reticulation. This also shows the extent to which the overhead lines within the city have been converted to underground cables.

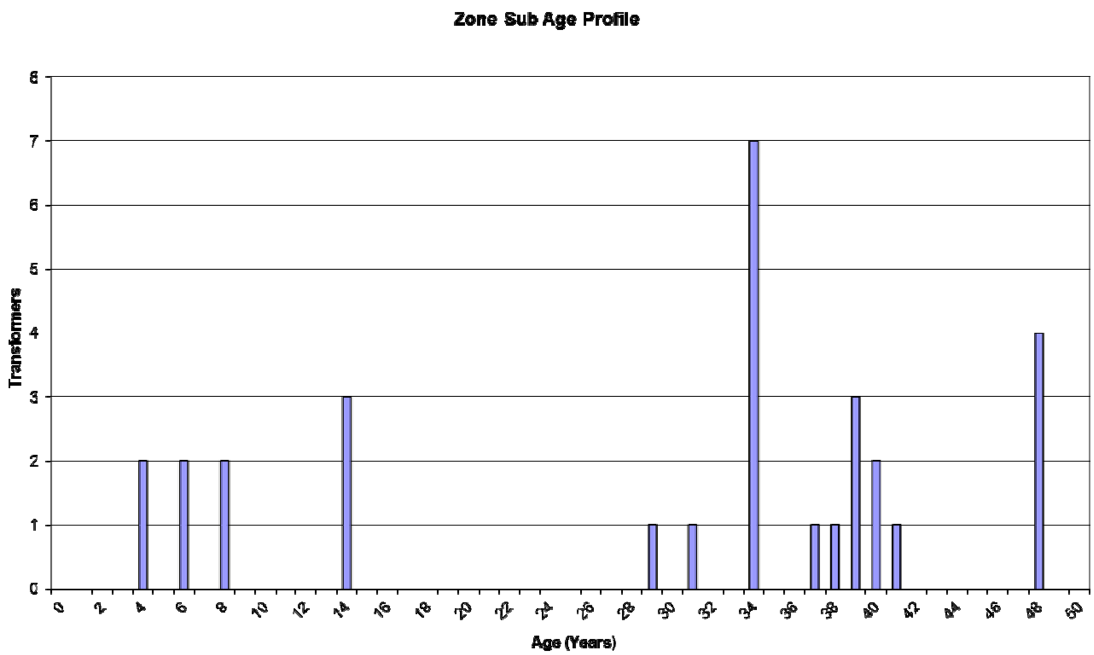
There are two meat processing works; (Alliance) supplied at 11 kV directly from Timaru and (Silver Fern Farms) supplied at 11 kV directly from the Pareora zone substation.

A summary of network assets replacement costs is shown in Appendix A

3.2.5 Major Zone Substations

A breakdown of the major zone substation components has been included in section 3.1.1.

The age profile of zone substation transformers is provided in the following graph.



- *Figure 3.4: Zone Substation Age Profile*

The zone substation transformer population is generally in good condition.

The Clandeboye No.1 T2 Transformer was removed from service for inspection and repairs due to gassing. This was undertaken during the dairy off season in 2011. The inspection revealed that there were a number of places where the core was shorting to the tank which were the main causes of the gassing. This was repaired and the transformer put back into service. Monitoring to date has shown no increase in gas levels after the repair.

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 will be refurbished and returned to service at Fairlie and Tekapo Substations in 2013-14. Following refurbishment they should have another 20 years of useful life at those two substations.

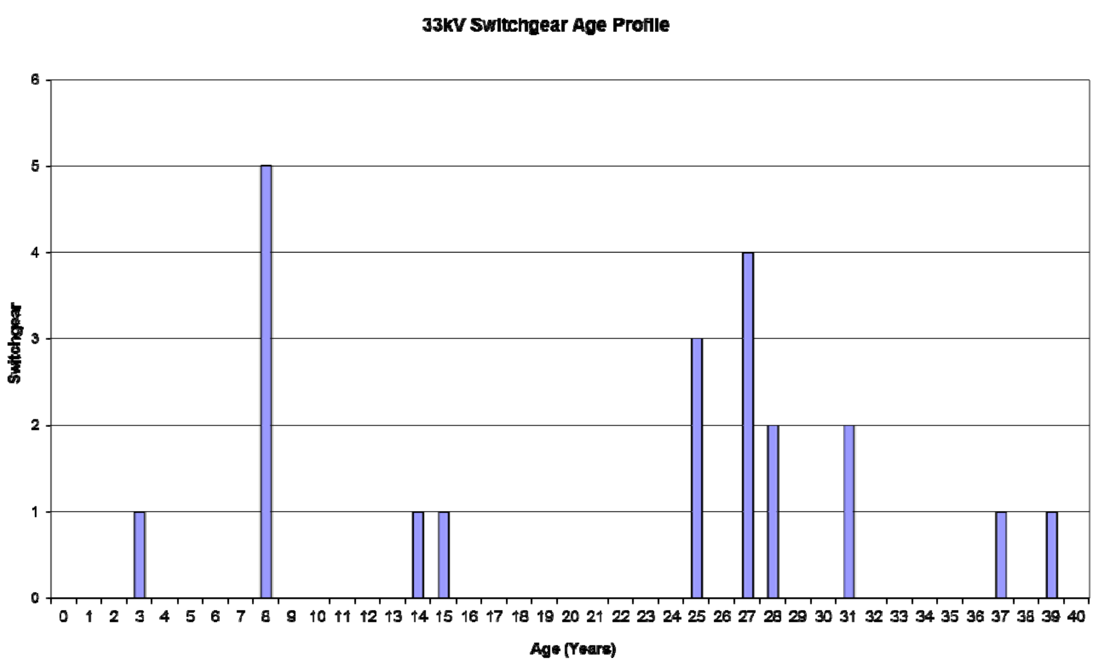
The 5/6.25/9 MVA transformer released from Rangitata in September 2012 requires its conservator to be enlarged due to an oil expansion contraction issue when fully loaded. This 1982 unit will be refurbished in 2013-14 at the same time that it has its conservator upgraded. It will then be redeployed.

Four new 9/15 MVA transformer sets were purchased (3 in 2011, 1 in 2012), and installed and commissioned at Pareora and Rangitata in 2012.

Victoria St substation was replaced by a new North St zone substation in 2011 as part of the development within the Timaru City area (neither Victoria nor North St include transformers – 11 kV switchgear only).

Grasmere St substation's 11 kV switchgear was replaced by new 11 kV switchgear in the 2012-13 financial year, with some refurbishment of the building.

Section 5 contains detailed information on the Zone Substation developments planned over the next few years.



- *Figure 3.5: 33 kV Circuit Breaker Age Profile*

There are twenty seven (*see below…*) 33 kV circuit breakers on the AEL 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. The older controllers (Form

3A) associated with the RVE style of circuit breakers are becoming less reliable and will be analysed for repair or replacement during the period of the plan.

Most of the 33 kV circuit breakers 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 SF6 insulated chambers. (Two old vacuum/oil CBs were decommissioned and may be redeployed)

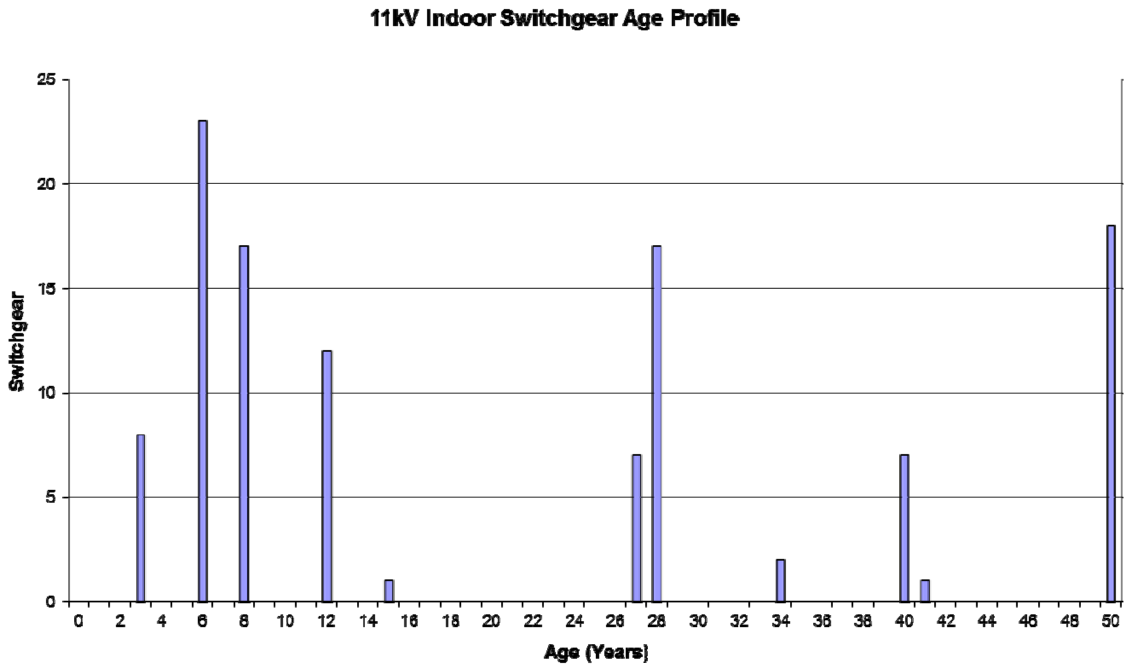
The two new 33 kV SF6 puffer type CBs commissioned at Rangitata Sub in 2012 are outdoor type. (one old vacuum/oil CB was decommissioned and may be redeployed).

The new 33 kV SF6 puffer type CB commissioned at Canal Road Corner in 2012, at the tap-off from the Clandeboye 33 kV Feeder #2 (overhead line) for the new Rangitata Sub line, is an outdoor type.

(The above nine new 33 kV CBs are not included in the above Figure 3.5 which is derived from asset database figures up to 31/03/2012).

Figure 3.6 over page 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.

The suites of 11 kV indoor circuit breakers at Grasmere (1962) had previously had the majority of their bulk oil circuit breaker trucks replaced with vacuum (17), the bus couplers (2) were the exception as manufacture was too difficult. This was an efficient means of extending the asset life, however the condition of the remaining switchboard protection and bus work indicated that more frequent assessment was required. As a consequence, the decision was taken to replace these switchboards. These switchboards were replaced with new VCB boards (20 VCBs) in the spring and summer of 2012-13 using the existing, but upgraded, building.



▪ *Figure 3.6: Indoor 11 kV Switchgear Age Profile*

AEL inspect circuit breakers in line with manufacturer's recommendations. 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 ten 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 panels 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.

Following the Christchurch earth quake in February 2011, general inspections of all Zone Substations were carried out with those substation buildings that exhibited possible damage being inspected by a consultant structural engineer. There was no serious structural damage to any substation building with only need for cosmetic repairs identified. These repairs were completed in 2012/13.

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

3.2.6 Distribution Lines and Cables

AEL's network consists of interconnected overhead circuits and underground cables operating at voltages of 33 kV, 22 kV, 11 kV, 6.6 kV and 400V.

The percentage of overhead and underground circuit kilometres to total circuit kilometres, regardless of construction type (i.e. three-phase, single phase, and SWER) at each voltage are as follows:

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

Refer below to tables 3.15: *Overhead Circuit Lengths* and 3.16: *Underground Cable Lengths* for details of in-service circuit kilometres for each voltage and construction type.

3.2.6.1 Overhead Lines – General

The overhead electrical network has been developed over several decades and with regular maintenance and growth 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 based on regular condition inspections and maintenance practices. 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.

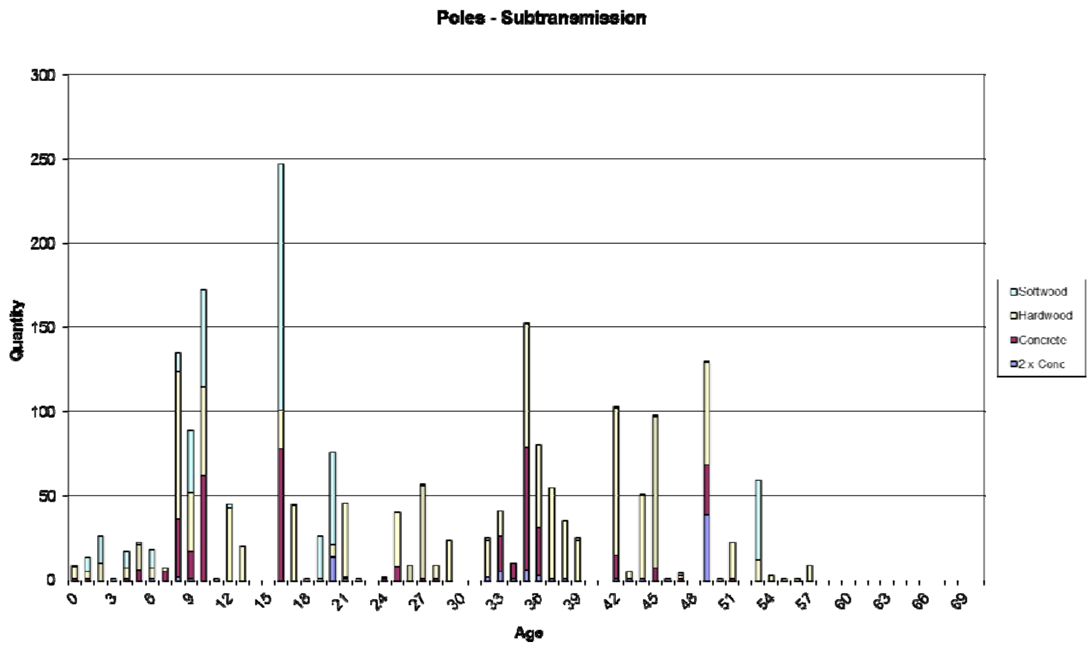
3.2.6.2 33 kV Sub-transmission

The following Chart illustrates the age profile of the 33 kV Sub-transmission poles.

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 replacement of alternate suspension insulator sets with post insulators as required. This approach provided an efficient and economical solution for the client and preserved AEL's existing asset value.

The Clandeboye Dairy Factory 33 kV line has experienced vibration since construction and was measured early in 2012. The results from both recorded locations are 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 encapsulating vibration amplitudes well below the safe vibration limits. No further action is required to reduce aeolian vibration on this line.

A second double circuit 33 kV designed line, built single circuit, was constructed in 2011 to provide an N-1 supply for the Rangitata Substation.



▪ *Figure 3.7: Sub-transmission Poles Age Profile:*

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.

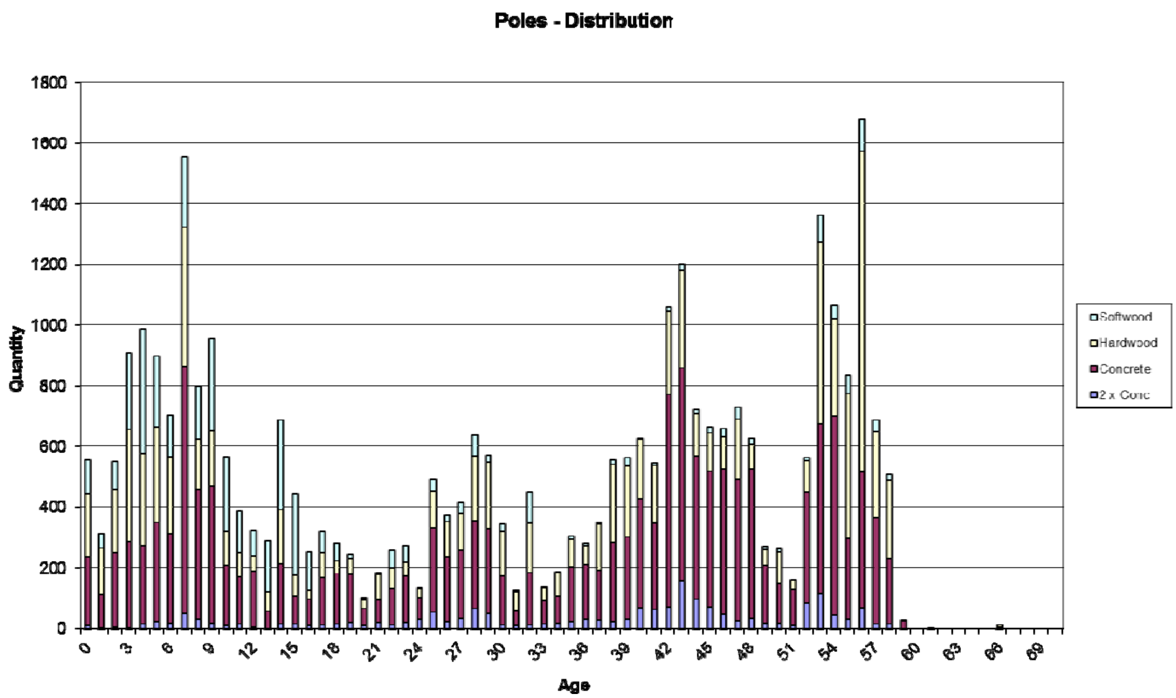
▪ *Table 3.15: Sub-transmission line Inspection Priority*

Location of line	Year of Construction	Maintenance Priority
Timaru Sub to Pareora Sub #1	1979 & 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	10
Tekapo Sub to Mt Cook Sub	between 1975 & 2001	8 & 11
Transpower Tekapo to Tekapo Sub	1991	9
Transpower Twizel to Twizel Sub	1968	7
Canal Rd CB to Rangitata Sub	2010	12

The two Timaru to Pareora substation 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.

3.2.6.3 11 kV and 22 kV Distribution

The following Chart illustrates the age profile of distribution line poles.



▪ ***Figure 3.8: Overhead Poles Distribution Age Profile***

The majority of the 11 kV and 22 kV overhead distribution systems were developed during the 1950's and 1970's. Very little development occurred during the 1980's and early 90's with load growth during this period being accommodated within the existing network capacity.

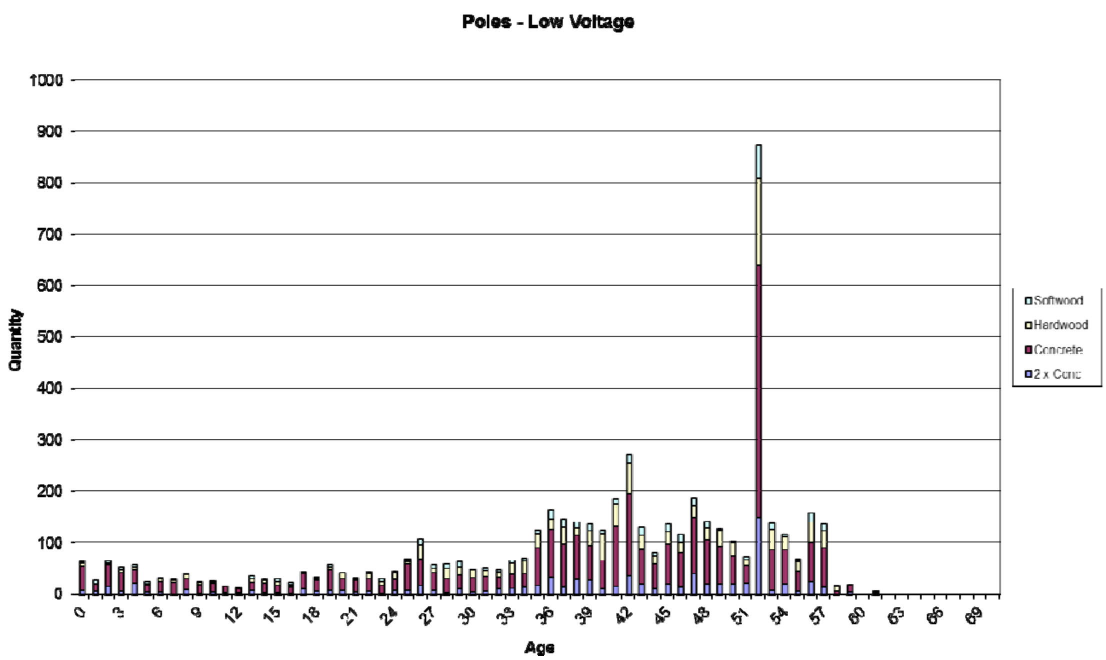
The past fifteen years has seen a significant growth in dairy conversions and irrigation which has been driven by the establishment of dairy factories at Clandeboye and Studholme. This investment has significantly increased the electricity demand in most rural sectors with the Mackenzie area being the exception at the moment.

Most of this increased load has required new line assets by replacement of existing lines with new poles to support larger conductor (hence defeating the need to maintain due to asset renewal from increased load) or reconstructing of some 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 graph above.

3.2.6.4 LV Distribution

The following Chart illustrates the age profile for LV overhead poles.



▪ *Figure 3.9: LV Overhead Poles Age Profile*

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.

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**.**

3.2.6.5 Poles and Crossarms

The network contains 43,282 poles as at February 2013. This number is derived from the GIS field capture project conducted in 2007 and subsequent works updates.

All poles have now been individually identified through this field capture project (2007) and entered into the GIS/AM database (2008-9), 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 22,232 concrete poles, 12,911 hardwoods, and 4,984 softwoods in the AEL system. (These numbers do not include stub or service poles).

The concrete poles have an estimated life of 50 **-** 80 years while the hardwood poles have a life of 40 **-** 50 years. Hardwood poles are an on-going maintenance concern, as they will eventually rot below ground level. Softwood poles are expected to last between 40-50 years. The premature failure of a softwood pole, due to brown rot, may necessitate inspection prior to their 25th birthday. 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 of ceasing their use if an economic replacement can be found. This is an industry safety issue.

With a population of 12,911 hardwood poles, an age based replacement estimate would indicate that on average, 260 **-** 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.

As many lines were installed during the 50's and 60'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 fifteen 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 **-** 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.

Areas predominately reticulated with hardwood poles between 1955 & 1961 have been inspected every ten years, and replaced as required, since 1985. Therefore these areas are being inspected for the fourth time. Approximately 10% to 20% of poles are replaced each time. Within the next 10 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 retaining no less than a ten year remaining life and a minimum 20 year remaining life for the oldest assets upon replacement of the 20% remaining components. This effectively staggers the capital required for end of life replacement with condition assessment and replacement at regular 10–year inspection intervals.

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 healthy heartwood.

The diameter of the remaining healthy heartwood is used to determine the remaining service life of the pole based on the required safe working load being met for a further ten 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 and a Network standard “Yellow Tag” used to indicate that the pole will not last another 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 design loads are replaced in conjunction with “Red Tag” poles.

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 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 first predominately concrete area to be targeted is between the Waitaki River and Waimate Township. The second area will be between Temuka and Geraldine. There are very few concrete pole replacements expected due to old age.

3.2.6.6 Insulators

The porcelain insulators used on overhead lines appear to have lives in excess of sixty years and have generally given good service. The most recent failures have occurred in recycled pin insulators, and have resulted from over tightening. Some 33 kV clamp top insulators, of one particular brand, have been replaced as a result of stress failure between the insulator and the metal clamp top. In the last twelve 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. The remaining silicone suspension insulators used on the Clandeboye double circuit 33 kV line have been replaced with porcelain post insulators as they showed signs of premature failure (crazing and chalking of the sheds).

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

Sites where the defective insulators have been used in Air Break Switch (Disconnector) and Blade or Fuse disconnect equipment are being identified and prioritised for replacement or refurbishment. Forty nine sites have been replaced over the last eight years with a further ten to twenty sites programmed for replacement over the next two years.

All grey and brown 11 kV porcelain strain disc insulators are now replaced with new glass discs during planned maintenance outages. Other such suspect porcelain components will be identified and replaced as required.

3.2.6.7 Conductors

Overhead conductors are either Copper 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.

- *Table 3.16: :Overhead Circuit Lengths*

Circuit kilometres of the overhead distribution network						
Construction Type	**33 kV**	**22 kV**	**11 kV**	**6kV**	**400V**	**Comms**
Three Phase	203.1	28.3	1859.5	0.0	228.4	n/a
Single Phase	0.0	115.9	865.4	0.0	63.2	n/a
Single Wire Earth Return	0.0	0.0	0.0	0.0	0.0	n/a

Conductors need to be treated differently as they would not have been replaced during maintenance. Conductor lifespan have been estimated at 60 to100 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 customers.

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 tensile strength due to designs incorporating many large spans. Some of these lines have been subject to intermittent vibration during their installed life. Periodic mechanical overloading conditions, from wind and snow, on many of the smooth body conductor will require further assessment of remaining service life.

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.

Some ACSR conductors (i.e. Gopher) manufactured prior to 1950, did not include greasing of the steel core. In areas where it had been installed in coastal environments between Studholme and Glenavy, Gopher is now starting to show 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. Continued condition assessment is required to determine remaining life and the level of capital expenditure and timing to maintain a safe and reliable network.

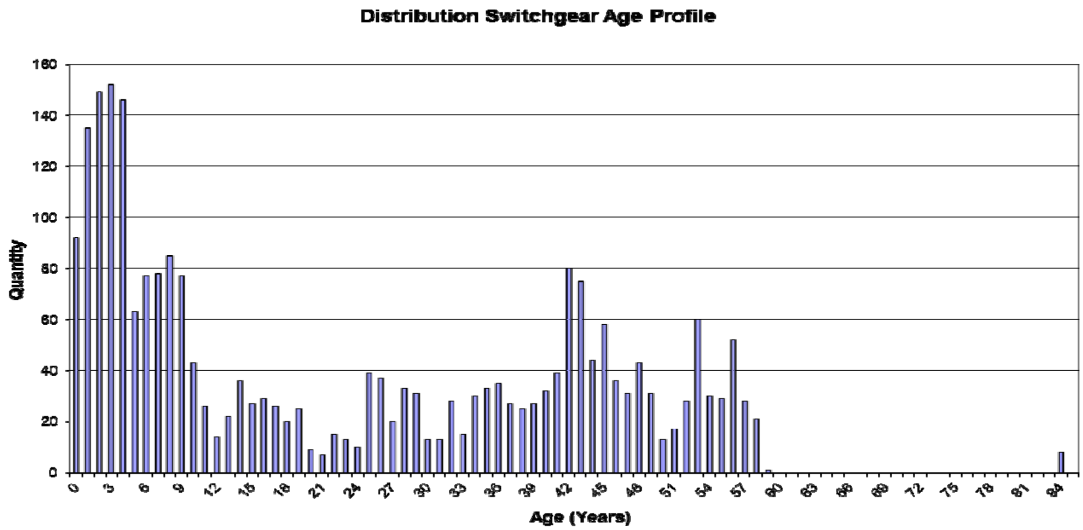
The corrosion of ACSR conductors has also become prevalent under the older type parallel groove (PG) clamps resulting in a small number of premature joint failures. PG clamps are now routinely replaced with AMPACT connectors during maintenance.

Modern design standards require shorter spans with reduced stringing tensions which result in a more resilient network asset.

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. AAAC conductors have recently been introduced to the network and have performed well to date.

3.2.6.8 Pole Mounted Switchgear



- *Figure 3.10: Distribution Switchgear Age Profile*

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 3.10 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.

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 50m 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.

3.2.6.9 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, Ikawai, Springbank, and Glenavy areas.

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.

3.2.6.10 Pole Mounted Transformers

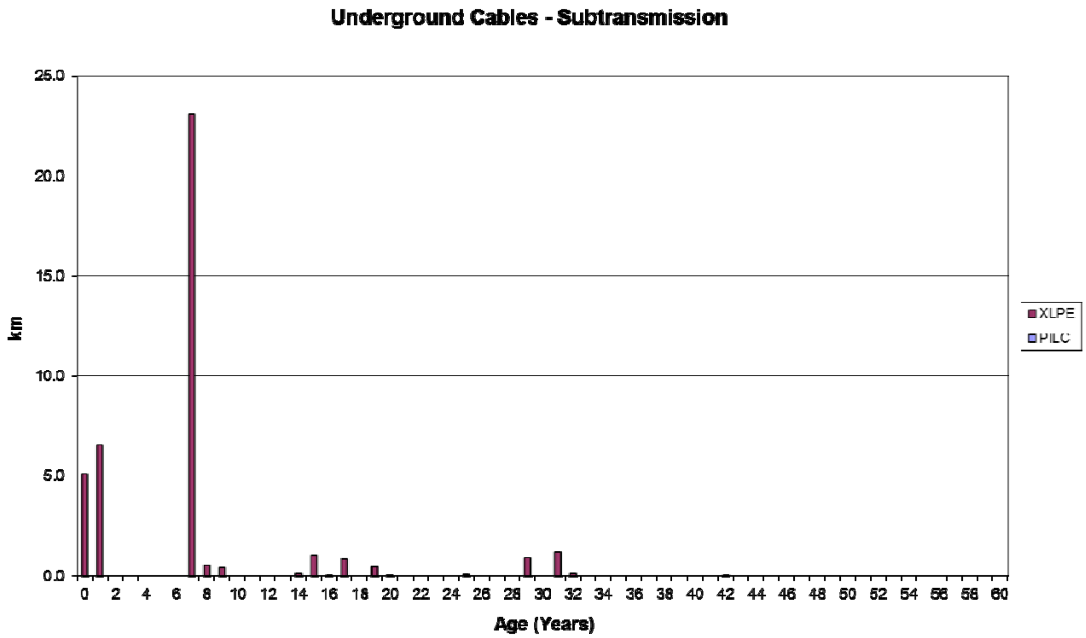
Due to seismic constraints the Network Standard requires any transformer 300 kVA or larger, to be ground mounted. During the next 20 years, the two pole overhead transformer structures in urban areas not meeting this standard, or seismic constraint criteria, will be converted to ground mounted design.

3.2.6.11 Underground Cables

The AEL network contains over 600 kilometers 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 customers 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.

▪ *Table 3.17: Underground Cable lengths*

Circuit kilometres of the underground distribution network:						
Construction type:	**33 kV:**	**22 kV:**	**11 kV:**	**6.6 kV:**	**400 V:**	**Comms:**
Three-phase	39.8	0.9	263.3	0.0	309.4	n/a
Single-phase	0.0	0.5	42.3	0.0	7.4	n/a
Single Wire Earth Return	0.0	0.0	0.0	7.2	0.0	n/a

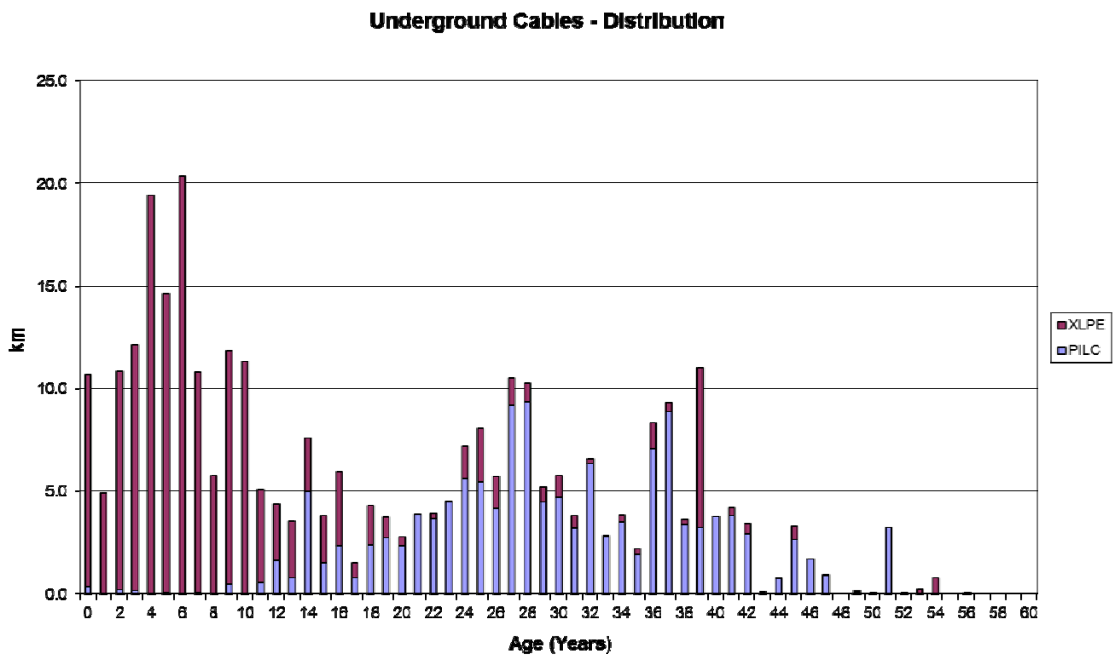


▪ *Figure 3.11: Subtransmission Cable Age Profile*

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 Alpine’s Network are less than 35 years old.

Major transmission cables in previous years were v.l.f. 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. Alpine have found that no quantitative analysis will help identify future cable faults at this point in time as most of AEL's cable faults are due to joint failure, unfavourable installation conditions, or foreign body or mechanical interference.



■ *Figure 3.12: Distribution Cable Age Profile*

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[1].

This 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 them 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. AEL expects very few cable replacements before 2030, however AEL will need to remain current on cable condition trends and make informed assessments of any premature failures to determine the effect on the remaining population's future performance.

[1] 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.

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 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. The majority of cable failures are due to the integrity of cable joints becoming compromised, typically by insulation failure, a further cause is cable strike by contractors.

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.

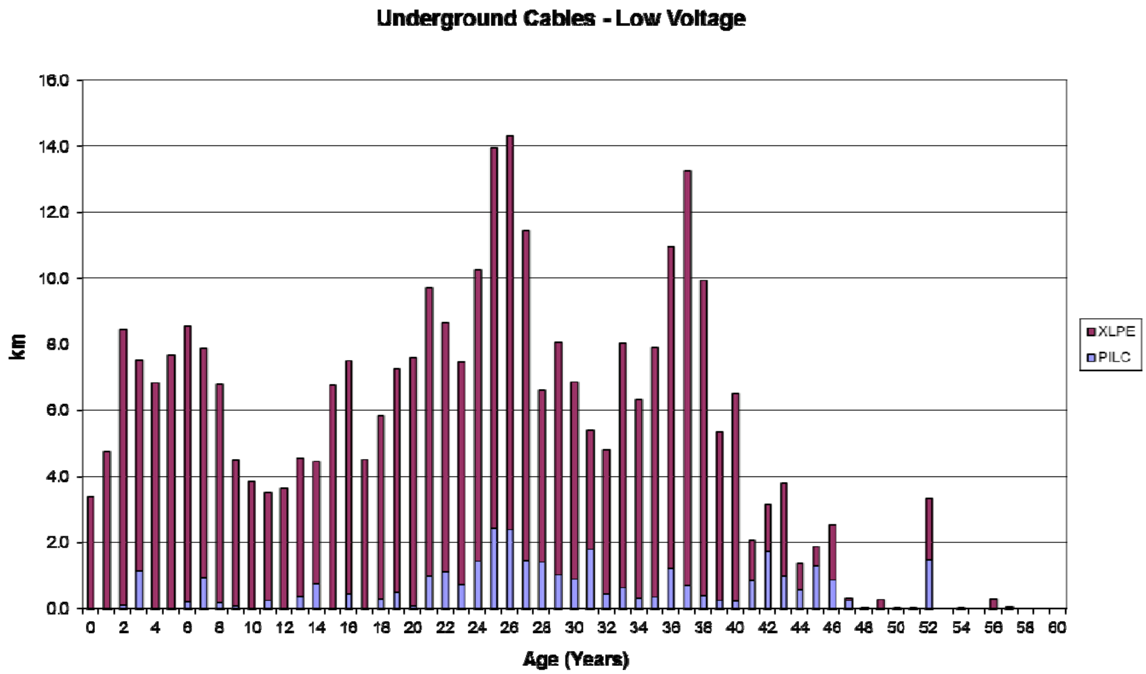
However, 2008 experienced a greater number of 11 kV cable and cable joint faults than expected. These were mainly due to contractor damage to cables while working on upgrading other services such as water and sewage for the Timaru District Council. The one or two other faults were the result of ‘1987’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

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. It is hoped that 2013 will see fewer incidence of this type as these contractors become more experienced at locating and avoiding AEL’s cables.

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 ‘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 the

2009-10 year had 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.



- *Figure 3.13: Low Voltage Cable Age Profile*

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 phenomena 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 – i.e. a CAPEX renewal project. If the heating is shown to be within the boxes themselves only, the maintenance solution will be of a relatively lower cost.

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 SF6 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:

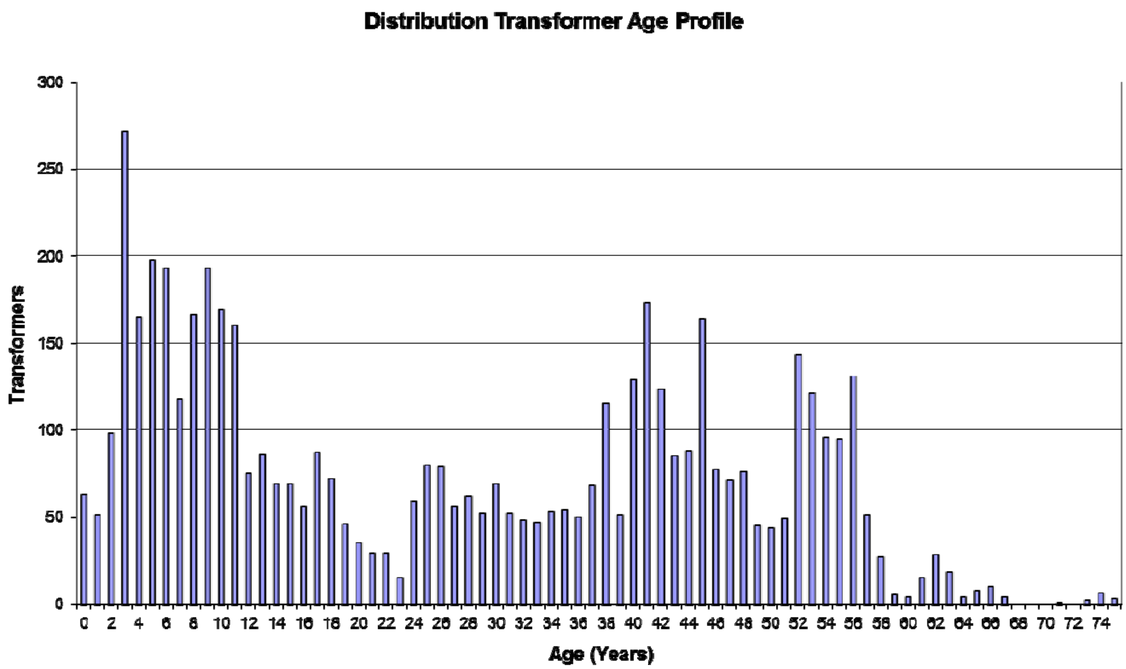
- LV switch/fuse-gear renewal (either within the underground substation or relocated above ground in boundary cabinets;
- HV RMU renewal to above ground berm location or upgrade to remote controllable RMU within the underground substation; and
- Renewal of the distribution transformer within the underground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

Please also refer to Section 6 Life Cycle Asset Management Planning.

3.2.7 Distribution Substations & Transformers

AEL has 5,458 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.



▪ ***Figure 3.14: Distribution Transformer Age Profile***

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 12ºC compared with the design standard of 20ºC.

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.

Alpine has 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 (i.e. rust) it is replaced and then mechanically and electrically refurbished. The transformer is returned to service with the next line maintenance. 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 821 transformers older than 50 years. However if no transformers are removed this will increase to 1,767 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. Alpine Energy is 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 3.18 below.

- *Table 3.18: 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	66	26	60	134	70	34	2	7	400
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	2,682	882	653	350	141	25	0	0	0	4,733
Pole Mounted (1.5 Pole)	0	0	0	0	1	0	1	0	0	2
Pole Mounted (2 Pole)	2	1	1	4	15	9	2	0	0	34
Substation (Ground Mounted)	1	3	3	4	6	2	10	1	4	34
Unknown Mounting Type	0	0	0	0	0	0	0	0	0	0
Total	**2,688**	**953**	**686**	**427**	**359**	**198**	**104**	**13**	**30**	**5,458**

3.2.7.1 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 AEL's 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 & HV cabinets),
- Building (dedicated or customer shared concrete block building).

A. Underground Subs:

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 400kVA 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 SF6 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.

B. Surface Mounted Subs

Surface mounted substations in AEL's 11 kV distribution network are of various sizes, designs and configurations, depending upon the era of installation, manufacturer and site conditions – i.e. Cubicle, Padmount, and Building types.

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

Most surface mounted substations would include an LV panel in the LV cabinet consisting generally of a frame supporting LV bus bars (3 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. As renewal solutions, AEL has an HRC fuse disconnect box change out for the Statters on the two pole subs, and uses the plastic type HRC shrouded fuse link ways as replacements for the Statters in the underground subs and surface mounted subs.

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.

3.2.8 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),
- Sectionalisers (pole mounted load break disconnectors),
- Load break switches (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 ferroresonance problems),
- Surge (Lightning) Arrestors.

3.2.8.1 Voltage Regulators

Voltage regulators are automatic devices that monitor the voltage on the line at the point of application and, according to its pre-settings, adjusts 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 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 100A (some older units) and 200A (newer units and current standard for the network). One set of 300 A regulators has been installed in a heavy feeder.

The rapid increase in irrigation and dairy related rural load in recent years has necessitated AEL 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 AEL's area.

3.2.8.2 Capacitors

11 kV Capacitors are another means of compensating for voltage drop on an 11 kV 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.

3.2.8.3 Reclosers

AEL uses pole mounted circuit breakers in rural areas, refered 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 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.

AEL uses only two or three sectionalisers in their system, preferring to adopt the recloser as a preferred rural device.

3.2.8.4 Load-break Enclosed Switches ("load break disconnectors")

These are generally SF6 or Vacuum insulated switches that are rated to break load but not fault current.

They 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.

AEL has only a few of these switches and they are configured for manual operation at this time.

3.2.8.5 Load-Break Disconnectors (air break switches fitted with interrupters)

These are effectively disconnectors with additional load break interrupter devices fitted to each phase unit to enable them to break load current. Certain types allow limited load make also.

AEL has dozens of these type of switch in service of different makes and types.

Some of the older types of these 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, AEL has standardised on an interrupter model which is much less prone to go out of adjustment..

3.2.8.6 Disconnectors (air break switches

AEL has 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.

3.2.8.7 HV Fuse Links

AEL has 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, which 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.

AEL is studying the use of a higher fault rated (22.4 kA verses 12 kA) drop out type fuse link for use in high fault level in parts of the Timaru area (the fault level on the Timaru GXP 11 kV bus is approximately 20 kA). This solution is proposed for existing transformers fed from overhead lines close to the GXP where the fault level has been estimated from load flow studies to be in excess of 10 kA. In 2012, Transpower installed 500 A NERs on their 110/11 kV transformers at Timaru which limit the P-E fault levels to less than 1,500 A (when all three banks are in service), but there will still be a need for the proposed higher rated fuse links for protection against phase to phase faults.

The transformers at Bells Pond Sub and Pareora Sub also have 500 A NERs fitted on their transformers' secondary (11 kV) neutrals.

3.2.8.8 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 and to prevent a short circuit developing that might trip the upstream protection. These leads may be replaced.

Sometimes lightning may be so severe that the arrester is destroyed but in most instances the arresters can operate effectively without sustaining any damage.

3.2.9 LV Reticulation Lines, Cables, including Link & Distribution Boxes

3.2.9.1 LV Overhead Lines

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.

AEL still has 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.

3.2.9.2 LV Underground Cables

Low voltage reticulation cables in service in the AEL area include four core, three core and neutral screen, and single core cables.

The current AEL 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.

3.2.9.3 Distribution Boxes (Boundary Boxes)

The connections between AEL’s 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.

AEL has 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.

The current AEL standard calls for a fully insulated plastic type box which accommodates up to 6 x 63A fuse bases.

The performance of these boxes in respect of public and operator safety, ease of installation, and AEL access is considered to be better than most.

3.2.9.4 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.

The link boxes currently being used for new construction are a fiberglass box type.

3.2.10 Protection Relays, SCADA and Communications Systems

3.2.10.1 Voice Radio

AEL’s 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 is used at times, to facilitate separate area control.

This voice radio arrangement is also used to return signals from six Zone Substations. These use tone encoding signals that feed through the SCADA Master. Controls and alarms are also sent and received over the radio system to each repeater site for on/off repeater linking.

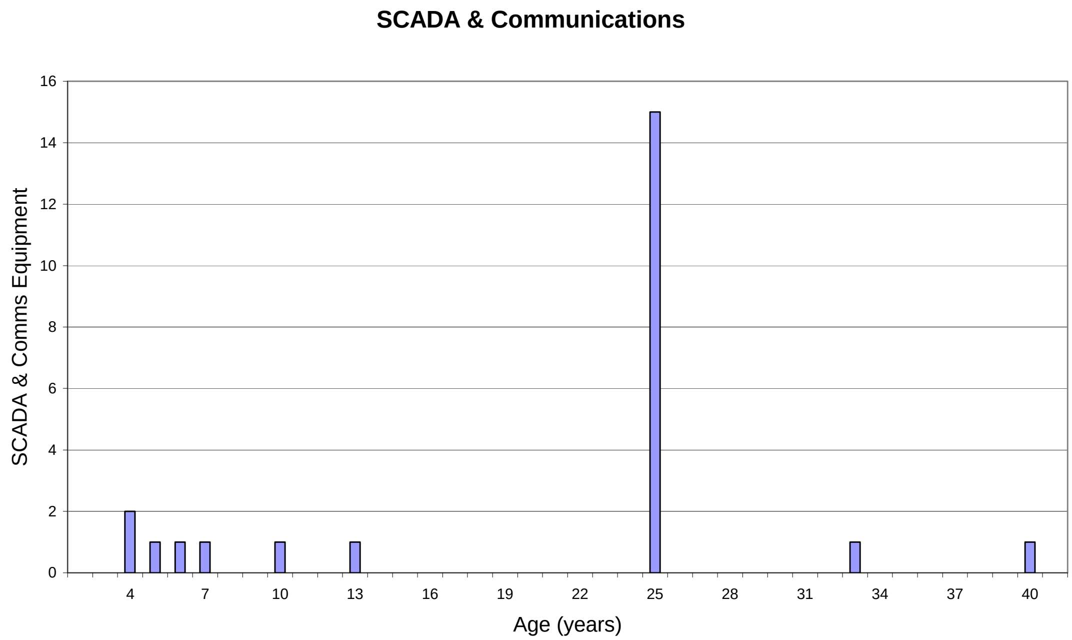


Figure 3.15: SCADA & Comms Age Profile

As represented in the above age profile, 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.

A report has been commissioned that outlines options for a suitable replacement radio platform which uses the next generation of technology. AEL 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 AEL's 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.

3.2.10.2 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 UHF FM digital, TCP/IP DNP3 protocol path;
- one hired microwave broadband TCP/IP link, DNP3 protocol path; and
- two land lines as communication paths.

A Communications Upgrade Project was initiated in 2008 with 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:

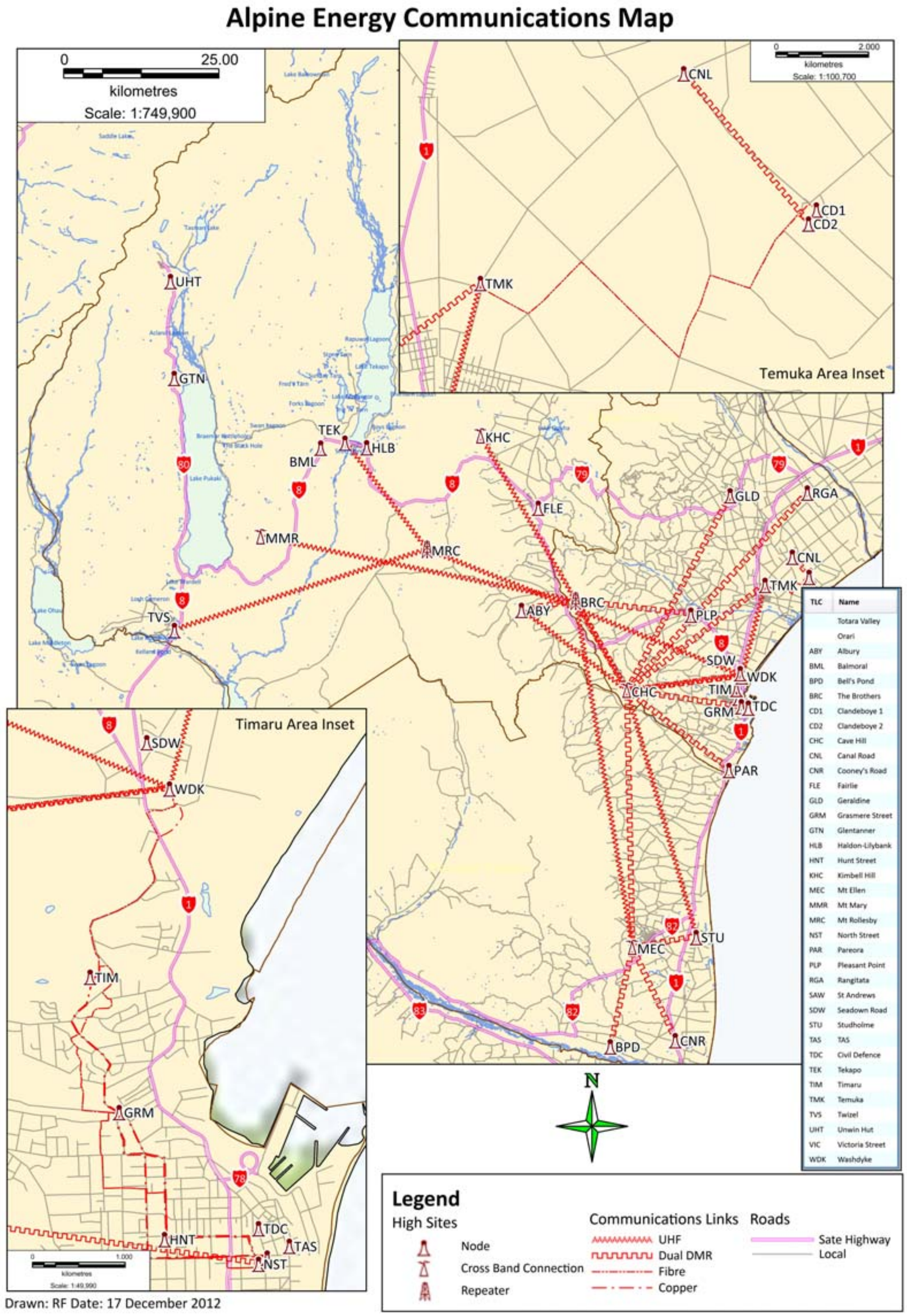
- Washdyke – Temuka substation (TCP/IP DNP3 protocol, from 2009).
- Washdyke – Mt Misery – Studholme & Albury substations (Conitel).
- Washdyke – Mt Rollesby – Twizel & Tekapo substations (Conitel).
- Washdyke – Timaru substation (Conitel on landline).
- Washdyke – Grasmere/Hunt/Victoria Substations (RS485 DNP3 landline)
- Washdyke **-** Bells Pond (hired microwave TCP/IP broadband, DNP3 protocol)

The "IPOWER" SCADA Master installed in 2006 at Washdyke continues to perform adequately since replacing the aging Realflex SCADA Master station which had become unserviceable.

The "ipower" platform allows for DNP3 communication to field RTU's and IED's. This will be the future communications protocol for AEL's radio network. AEL has replaced 2 RTU's in conjunction with zone substation switchboard replacement projects, however protection relays are now providing alternative data access through internet protocol devices which may reduce the requirement for RTU's.

The BCL broadband path between Washdyke and Temuka had suffered from increasing intermittent problems that were initially difficult to isolate as configuration issues with the Temuka RTU had masked the comms problem. Once this path was replaced in late 2009 with a direct UHF digital radio TCP/IP DNP3 link (using the existing UHF aerials), the comms & RTU problems were quickly resolved.

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.



- ***Figure 3.16: Alpine Energy Ltd – Data Communications:***

3.2.10.3 Load Control Ripple Injection Plant

AEL operates load control of energy storage devices (e.g. hot water cylinders) located at consumers premises via operation of ripple injection plants located at Timaru, Studholme, Temuka, Albury and Tekapo. Details of the plants are contained in tables under section 3.2.4.

3.2.10.4 Protection Relays

AEL has a number of different types of protection relays on its Network. These include;

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

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

- tripping source, generally a battery
- instrument transformers (e.g. CTs, NCT, VTs, etc.)
- protection relays
- wiring looms
- trip coils in the circuit breaker/recloser
- close coils in the circuit breaker/recloser
- circuit breaker/recloser mechanisms and contacts
- fuses
- auxiliary contacts
- terminal blocks
- etc.

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. The AEL Network contains a variety of subtransmission, GXP and Zone Substation arrangements with quite varied fault levels. Each arrangement and fault level combination requires a particular protection application. Consequently, the simpler network arrangements with low fault levels have suitably simple protection schemes (e.g. rural Zone Substation with small single transformer bank) while the more complex network arrangements with high fault levels have quite complex schemes (e.g Timaru CBD’s three 11 kV Switching Substations with closed ring 11 kV subtransmission interconnects and TP GXP supply cables).

As part of AEL’s 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. AEL also has 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.

3.2.11 Meters and Load Control Relays at Consumer Premises

AEL has provided meters and relays at consumer's premises for Electricity Retailers as part of our current standard use of system agreement. From June 2013 AEL will become a meter equipment provider (MEP) under part 10 of the Electricity Act. Retailers may choose to use AEL 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 form our meters as interracial 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, avoiding the need to install more expensive load control equipment on our network.

A programme of recertification of meters was initiated in 2010.

3.2.12 Embedded Generation

Major embedded generation on our network is the 7MW 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 twenty percent so is not available regularly for improvement in supply security, however can be used, subject to owners consent for islanding to maintain local supply during Transpower outages for one or two days per year. The generator is unable to black start, hence is not deemed a secure supply during islanding operations.

3.2.13 Distributed Generation

Interest by AEL consumers to install PV systems with inverters that permit export of surplus energy to energy traders back through the electricity network is growing. 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 the AEL area, AEL recently installed a PV array and Inverter system on the Tekapo Substation building. AEL's Internet site provides public access to this data.

3.2.14 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 details for re-investment are discussed in the Section 5 – Developing New Assets. The options for network development and configuration are discussed in detail in Section 5.7

3.3 Justifying Assets

A key measure of justifying assets is the degree of optimisation applied by the Commerce Commission's ODV valuation methodology, and accordingly AEL recognises 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, AEL also recognises that its 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 Section 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 subtransmission 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 i.e. Over investing creates service levels before they are needed, but under-investing can lead to service interruptions (which typically costs about 10x to 100x as much as over-investing as was discovered in Auckland in June 2006).
- the discrete sizes of many classes of components to be recognised e.g. 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 customers, as well as meeting regulatory voltage requirements. A small number of assets have been optimised for ODV purposes (most recently in 2004). However all of these optimisations have been capacity related (i.e. 33 kV line operating as 11 kV therefore recorded as an 11 kV line, or a medium conductor optimised to a light conductor, no assets have been identified as being superfluous).

Key new load areas are developing adjacent to river boundaries for irrigation of farmland to meet higher land productivity. Assets supplying these areas are being transformed from single to three phase while core assets are being strengthened in capacity and augmented with voltage regulation. From here feeder load can be diversified with additional lines to provide capacity and improved supply security. Customer expectations are also an important consideration as supply for the dairying load is preferential to irrigation load should the occurrence of a 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. AEL owns 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 Appendix E.

4.

Service Levels

AEL sets its various service levels according to the following principles:

- What is most important to consumers?
- How well does AEL achieve what consumers have said is most important?
- What trade-off between price and quality of service is acceptable to consumers?

These issues are discussed more fully in the results of Alpine's consumer surveys for 2006, 2008, 2009, and 2012, in Section 4.2 below.

4.1 Creating Service Levels

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

4.2 Consumer Service Levels

To determine consumer's preferences for price and supply quality AEL has increased the scope of its consumer surveys over the last 6 years. The most recent survey (2012) examined the following 3 market segments:

- *Table 4.1: Consumer Survey Segmentation*

Segment	Sample nature & size
Top 25 consumers	All 25 consumers regardless of GXP area.
Top 26 to 125 consumers	Random sample of 30 regardless of GXP area.
Mass market	Random sample of 500 pro-rated across the 7 GXP areas.

Engagement with these market segments has revealed that these consumer's preferences for service levels fall into three distinct classes:

- Primary service levels comprising continuity of supply ("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.

These are described more fully below.

4.2.1 Primary Consumer Service Levels

The surveyed consumers have clearly indicated that they value continuity and then restoration most highly. To measure performance in this area the following three internationally accepted indices have been adopted:

- **SAIDI – system average interruption duration index**. This is a measure of how many system minutes of supply are interrupted per year and is calculated as follows:

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

- **SAIFI – system average interruption frequency index**. This is a measure of how many system interruptions occur per year and is calculated as follows:

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

- **CAIDI – consumer average interruption duration index**. This is a measure of how long the "average" consumer is without supply each year and is calculated as follows:

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

Projections of these measures for the ten years ending 31 March are set out in Table 4.2 below.

- *Table 4.2: Primary consumer service levels*

Measure	Year Ending 31 March									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
SAIDI	164	164	164	157	151	145	139	134	128	123
SAIFI	1.69	1.69	1.69	1.69	169	1.69	1.69	1.69	1.69	1.69
CAIDI	97	97	97	93	89	86	82	79	76	73

The above Table 4.2 includes revised 10–year target levels for SAIDI and SAIFI. Information on 5–year forecasts for class B and C interruptions for SAIDI and SAIFI can be found at Schedule 12d: Report Forecast Interruptions and Duration at Appendix I.

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 improve the efficiency of switching for planned outages and reduce the response time associated with switching for faults.

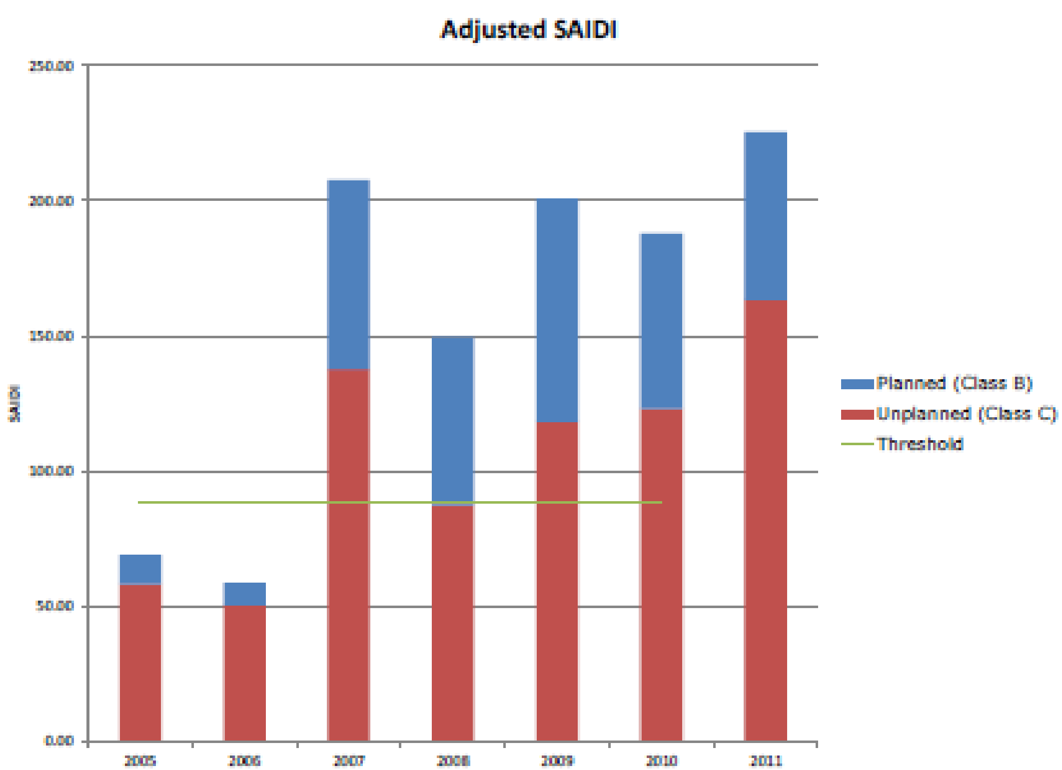
The revised SAIFI targets to a constant level are to allow savings from reduced frequency of outages from faults to permit more planned outages to improve access to the Network for required maintenance, extension, and CAPEX projects.

4.2.2 Justification of Previous Service Level Targets:

Prior to 2010, the SAIDI and SAIFI were based on actual performance information submitted to the Commerce Commission for the period 1999 to 2004. This resulted in AEL being set a SAIDI threshold of 88.2 SAIDI minutes.

Historic performance against target levels is depicted in Figure 4.1 below.

The numbers shown are ”normalised” values (i.e. after applying the Commerce Commission’s calculation to compensate for major event days). It is evident that there was a step change in performance level from 2006/07 onwards which on that face of it might imply that performance worsened drastically year–on–year. However, actual performance after 2006/07 remained at approximately the same level which raised the question as to why this is since AEL did not receive increased complaints from customers regarding performance.



- ***Figure 4.1: Historic SAIDI Performance***
  (graph courtesy of Strata Consulting)

The trend shown at Figure 4.1 above prompted an investigation into the causes for the perceived worsening performance which resulted in the following conclusions and explanations for the recorded performance.

AEL only moved to a centralised control room in 2009. Prior to this performance data was compiled at a regional level by the respective network controllers of which there were four. The central control room took overall responsibility for recording and reporting on outages. Significant effort was put into developing a more comprehensive outage information capturing system.

AEL also appointed an Asset Manager in 2008 responsible for asset maintenance and condition monitoring. It was soon realised that very limited maintenance had been done on the AEL network. To remedy this, a concerted effort was made to initiate condition assessments on various types of plant and to increase necessary maintenance to comply with health and safety requirements, manufacturer recommendations and regulatory compliance. This increased maintenance effort from 2008 onwards resulted in increased planned outages.

In 2006 AEL experienced a severe snow storm that left 10,000 customers without power and took 16 days to get power restored to all customers. A summary of the damage included 431 damaged poles, 196 broken cross arms, over 430 km of overhead lines broken and damaged. The repairs and maintenance related to this event took three years to complete and as a result normal planned maintenance fell well behind the intended schedule.

During the 2010/11 AMP preparation period, AEL decided to increase the target levels for SAIDI from 90 to 180 minutes. This was based on actual levels over recent years as well as a comparison to other distribution companies that matches AEL's network topology, weather conditions and geography and the New Zealand distribution industry average performance. This number was approved by AEL's board. Subsequently the Commerce Commission undertook an investigation into AEL's reliability performance and the SAIDI target levels listed in Table 4.2. are based on a realistic scenario as described in the investigation consultants report.

AEL recognises that these performance measures are rather academic and that don't have a practical meaning for individual consumers, i.e. SAIDI minutes are not the same as actual minutes without electricity supply. Table 4.3 shows consumers the number of outages they might broadly expect in any given year by broad geographical areas.

- ***Table 4.3: Expected reliability 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 & Port, including Polar Cold, Coolpak, & Port of Timaru	2 outages of 3 hours every year	2 outages every year
Suburban Timaru	2 outages of 2 hours every year	2 outages every year
Waimate, Temuka, Pleasant Point,	1 outage of 5 hours per year	2 outages every year

General Location	Sustained Outages	Momentary Outages
Fairlie, Geraldine, Tekapo and Twizel urban areas, including NZ Insulators, Canterbury Woolscourers, South Canterbury Byproducts, and Fonterra Studholme.		
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

Continuity of supply is obviously a fixed assets issue which is not always easy and certainly not cheap to address. However restoration can be process driven (noting that meshing feeders is a fixed asset approach to improving restoration) and one area where the largest consumers have said that AEL could do better is to advise them the likely restoration time so they know which of their contingency plans to implement.

Consumers in all 3 market segments surveyed strongly indicated a preference for paying about the same line charges to receive about the same level of supply reliability.

4.2.3 Secondary Consumer Service Levels

Secondary service levels are those attributes which consumers rank behind continuity of supply and restoration. These service levels are timely shutdown notices and no flicker. In the 2009 survey, timely shutdown notices had overtaken no flicker in importance to consumers. The Secondary Consumer Service Level the latest consumer survey undertaken in 2012 has reversed this preference amongst industrial consumers. Industrial consumers most recently put no flicker before timely shutdown notices. Domestic consumers were spread in their opinion on these two aspects of electricity supply.

- **Absence of flicker -** in a long and almost totally overhead network surrounded by trees in windy and snow-prone areas, eliminating or even reducing flicker is obviously a big task, one which Alpine is not sure it can practically do much about. The recent adoption of heat pumps by residential consumers has shown some earlier models depressed the voltage when starting due to the direct-on-line nature of their motors. This has also caused a “flicker” problem with due to cheaper products being imported which are not suitable for local use. However our consumer engagement has also revealed the following:
  - Flicker tends to be more noticeable than problematic for many consumers.
  - 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.

- Other research indicates that 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** – this is something that can be improved and moreover it can be done by improving processes in non-real time (as distinct from reducing flicker which would require fixed asset solutions). Alpine acknowledges issues such as working 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 4.4 sets out the secondary consumer service levels AEL expects to achieve over the next three years.

Table 4.4: Secondary Consumer Service Levels

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 5 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

4.2.4 Tertiary Consumer Service Levels

Tertiary service levels are the attributes that consumers have said are of least importance such as answering the phone quickly, processing new connection applications or providing technical advice. Table 4.5 sets out the tertiary consumer service levels we expect to achieve over the next 3 years.

- *Table 4.5: Tertiary Consumer Service Levels*

Service Level		Year Ending 31/3/14	Year Ending 31/3/15	Year Ending 31/3/16
Answering phone				
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%

Fortunately these attributes are process driven and relatively inexpensive to improve. However this puts lines businesses such as AEL in an awkward position in that its consumers' biggest wants are the most expensive and difficult to deliver whilst their lesser wants are much easier to deliver. Moreover the lack of substitutability between the three classes of service levels means that AEL cannot trade-off simple improvements in tertiary service levels such as answering the phone faster whilst allowing primary service levels such as continuity and restoration to languish.

4.3 Regulatory Service Levels

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

- keep annual price increases within the allowed price path under the default price-quality path.[1]
- ensure that SAIDI and SAIFI performance, in any given year, does not exceed the quality path based on the reference period 1 April 2004 to 31 March 2009
- publicly disclose, and provide to the Commerce Commission, an AMP in accordance with clause 2.6.1 of the Electricity Distribution Information Disclosure Determination 2012
- publicly disclose information prescribed by the Commerce Commission under the information disclosure requirements annually.

AEL's expected internal performance and efficiency measures as required by the Electricity (Information Disclosure) Requirements 2012 are set out below.

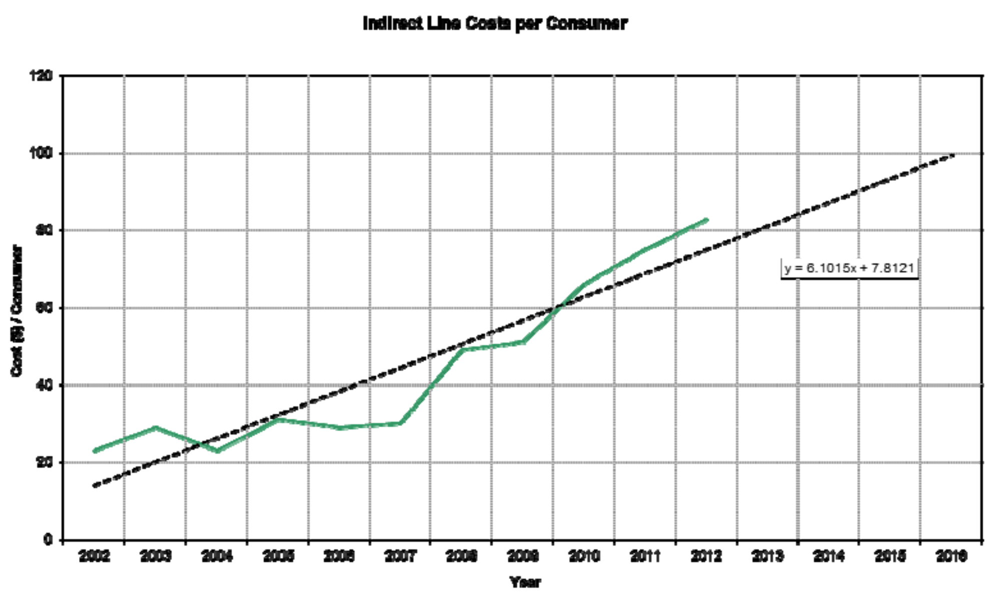
4.3.1 Financial Efficiency Measures

The projected financial efficiency measures are shown below. These measures are:

[1] Alternatively, apply to the Commerce Commission for a customised price-quality path that better meets acceptable levels of reliability, security and return on investment to AEL

- $\textit{Direct costs per km of line} = \dfrac{\text{direct expenditure as defined in the disclosure requirements}}{\text{system length at year end}}$
- $\textit{Indirect costs per ICP} = \dfrac{\text{indirect expenditure as defined in the disclosure requirements}}{\text{number of ICPs at year end}}$

▪ *Figure 4.2: Direct Line Costs per km Trend*



▪ *Figure 4.3: Indirect Line Costs per Consumer Trend*

4.3.2 Energy Delivery Efficiency Measures

Alpine's energy delivery efficiency measures are defined below. These measures are:

- **Load factor** = $\dfrac{\text{kWh entering the network during the year}}{[\text{max demand for the year}] \times [\text{hours in the year}]}$
- **Loss ratio** = $\dfrac{\text{kWh lost in the network during the year}}{\text{kWh entering the network during the year}}$
- **Capacity utilisation** = $\dfrac{\text{max demand for the year}}{\text{installed transformer capacity}}$

Historical data measured according to these definitions are depicted in Figure 4.3 below.

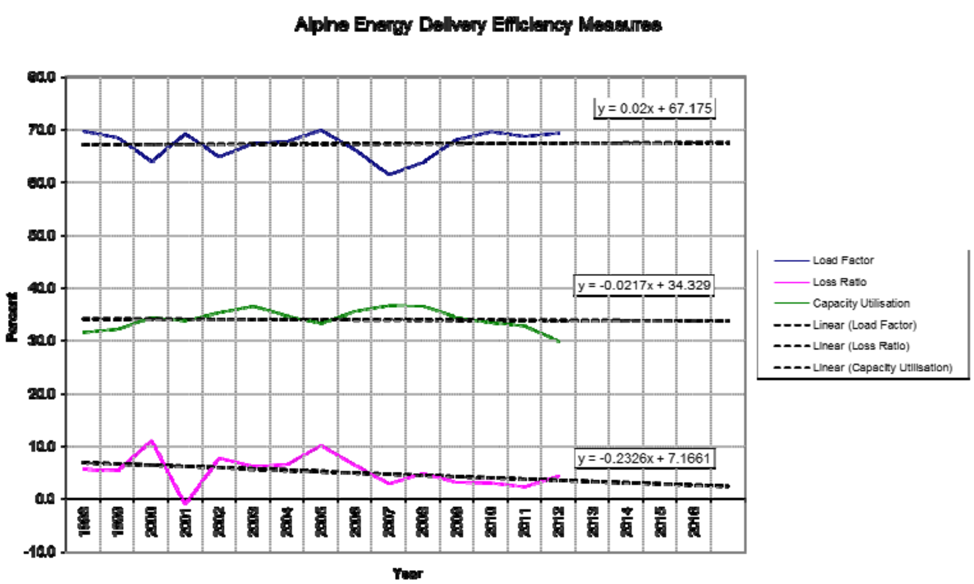


Figure 4.4: Delivery Efficiency Measures Trend

Based on historical numbers the projected energy delivery efficiencies are listed in Table 4.6 below.

Table 4.6: Projected energy delivery efficiencies

Measure	2012	2013	2014	2015	2016
Load Factor	66.9	66.9	66.9	66.8	66.8
Loss Ratio	3.9	3.7	3.4	3.2	3.0
Capacity Utilisation	34.0	34.0	34.0	34.0	33.9

4.4 Other Service Levels

AEL also creates a number of service levels that benefit other stakeholders such as safety, amenity value and absence of electrical interference.

4.4.1 Public Safety

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

- Health & 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.

4.4.2 Amenity Value

There are a number of requirements that limit where and how overhead power lines are built:

- The Resource Management Act 1991.
- The operative Timaru, Mackenzie and Waimate District Plans.
- Relevant parts of the operative Canterbury Regional Plan.
- Land Transport requirements

In general, new assets will be underground in urban areas which is significantly more expensive. Undergrounding sectionsof the network may create reliability levels beyond what consumers generally expect and are prepared to pay for.

While most lines are a permitted activity under the RMA, and District Plans, there is an increasing conflict between the Electricity Act providing access to road corridors and the road controlling authorities placing unreasonable limitations. This is time consuming to resolve and often incurs additional costs.

4.4.3 Electrical Interference

Under certain operational conditions AEL assets can interfere with other utilities such as phone wires and railway signalling or with the correct operation of AEL's own equipment or customers' plant. The following codes imposes service levels.

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

As well there are instances where customers' equipment can operate in a manner that interferes with others customers supply and therefore is required to be isolated from the connection to the network. Some older style of heat pumps with direct-on-line single phase motors can cause voltage flicker on starting. Another main type of plant is variable speed drives (VSD's) used to a large extent to drive irrigation pumps. The VSD's inject unwanted harmonic currents into the network which results in harmonic voltages due to the network impedance. AEL manages this phenomenon through its Network Harmonic Standard in an effort to protect other consumers' equipment from this power quality issue.

4.5 Justifying Service Levels

AEL justifies its service levels in one or more of the following ways:

- On the basis that the majority of consumers have expressed a preference for approximately the same level of continuity and restoration in return for paying about the same line charges.
- By what is achievable within AEL's constrained revenue.
- By the physical characteristics and configuration of the network that embody an implicit level of reliability which is expensive to significantly alter (but which can be altered if a consumer or group of consumers agrees to pay for the alteration).
- Because of the diminishing returns of each dollar spent on reliability improvements.
- By a customers' specific request (and agreement to pay for) a particular service level.
- When an external agency imposes a service level or in some cases an unrelated condition or restriction that manifests as a service level such as a requirement to place all new lines underground or a requirement to maintain clearances.

Consumer surveys in the past have indicated that consumer preferences for price and service levels are reasonably static – there is certainly no obvious widespread call for increased service levels. However Alpine does note the following two issues that have a flow-on effect:

- The service level called "public safety" will need to increase with the requirements of the Electricity (Safety) Regulations 2010.
- Food and drink processing, storage and handling are subject to increasing scrutiny by overseas markets, and in particular interruptions to cooling and chilling are less acceptable. This requires Alpine's cold storage consumers to have higher levels of continuity and restoration.

5.

Network Development Planning

Over recent years development plans have been driven primarily by demand (customer led growth or generation either within or outside of the existing network footprint) and regulatory compliance. The Commerce Commission conducted a review of AEL's reliability performance in 2012. As a consequence of the findings of the Commission's review a number of developments have been made in this AMP reporting period that focus on improving quality and reliability.

At its most fundamental level, demand is created by a consumer drawing (or injecting) energy across their individual connection. The demand at each connection aggregates "up the network" to the distribution transformer, then to the distribution network, the zone substation, the sub-transmission network back to the GXP and ultimately through the grid to a power station.

By extension these fundamental drivers of load demand and regulatory compliance manifest themselves in more specific engineering drivers such as: security of supply, quality of supply, capacity of lines and plant, voltage regulation, safety, and environmental compliance.

5.1 Planning Criteria and Assumptions

5.1.1 Planning Unit

For incremental planning of the network at large, AEL has adopted the 11 kV feeder as its 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 (i.e. beyond what might be considered incremental) AEL's planning principles and methods still apply, but in the context of building new (possibly dedicated) assets at 11 kV or possibly even 33 kV.

5.1.2 Planning Approaches

Assets are planned in three different ways (strategically, tactically and operationally) as shown in Table 5.1 below:

Table 5.1: Planning approaches

Attribute	Strategic	Tactical	Operational
Asset description	• Assets within GXP. • Sub-transmission lines & cables. • Major zone substation assets. • Load control injection plant. • Central SCADA & telemetry. • Distribution configuration e.g. 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 (e.g. 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”.

As a further guide AEL uses the following “investment strategy matrix” shown below in Figure 5.1 which broadly defines the nature and level of investment and the level of investment risk implicit in different circumstances of growth rates and location of growth.

- ***Figure 5.1: Investment Strategy Matrix***

Location of demand growth	Lo	Hi
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

Predominant examples of CapEx modes are:

- **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.

5.1.3 Trigger Points for Planning New Capacity

Because new capacity has ODV, balance sheet, depreciation and ROI implications, AEL will always try to meet demand by other, less investment-intensive means. This discussion also links strongly to the discussion of asset life cycle in section 6.2.

The first step in meeting future demand is to determine if the projected demand will result in any defined trigger points for asset location, capacity, reliability, security or voltage being breached. These points are outlined for each asset category in Table 5.2.

If and only if a trigger point is breached does AEL then move to identify a range of options to bring the assets' operating parameters back to within the acceptable range of trigger points. These options are described in section 5.2 which also embodies an overall preference for avoiding new CapEx.

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 & 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 & 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 & cables	Load cannot be reasonably supplied by configuration therefore requires network extension with new distribution lines or cables.	Conductor current or fault level exceeds thermal rating.	Snow loading needs higher mechanical strength. Cable fault damages light screens or partial discharge is poor	Excursion beyond triggers specified in section 5.2.2	Voltage at HV terminals of transformer consistently drops below 10.5kV and cannot be compensated by local tap setting.	Age hardening or loss of conductor strength. Corrosion of steel 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 & 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 & condition of conductor, insulation levels or supports.

5.1.4 Quantifying New Capacity

5.1.4.1 Theoretical Considerations

The obvious theoretical starting point for quantifying new capacity is to build just enough just in time, and then add a bit more over time. However AEL recognises the following practical issues:

- 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 price-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).

AEL's guiding principle is therefore 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.

5.1.4.2 Capacity of New Assets

The capacity of components and sections of the network is considered when planning developments. The following planning criteria influence the decision on the capacity of equipment to be used in designs:

- Reliability and Security of supply

  The security standards that may be adopted by AEL follow the issue of the revised EEA "Guidelines for Security of Supply in New Zealand Electricity Networks" (presently in preparation). In essence this would mean that on the sub-transmission system (in AEL's case the 33 kV system, or 33 kV assets operated at 11 kV, and the Timaru CBD 11 kV Subtransmission cables), AEL would strive to achieve an N-1[1] security level. However several existing 33 kV subtransmission lines do not have N-1 security such as Geraldine, Fairlie, Pleasant Point, Tekapo, Mt Cook line, Twizel, and Rangitata at present.

  With regard setting a MW level or ICP number at which N-1 supply security is required, it is difficult on the AEL 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 supply to Timaru CBD, milk processing plants, dairy farms, tourism

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

destinations, meat works, irrigation concerns, &c., where loss of supply could have significant economic and possible environmental consequences.
The AEL 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 detailed above within the 10–year planning period adopted within this plan.

Existing security levels are listed in Table 5.3.

- Voltage Regulation

  The capacity of equipment that may influence voltage regulation is chosen to ensure AEL complies with the Electricity Regulations to control the voltage within ±6% of the declared (or nominal) voltage, except for momentary fluctuations (i.e. voltage dips).

  Equipment implied in this category are: transformers, OLTCs, voltage regulators, capacitor banks, cables and overhead conductors.

- Harmonics

  Voltage and current harmonics are becoming more important with the large number of variable speed drives (VSD's) being installed on AEL's network, specifically to drive irrigation pump motors. Since harmonics generated by one customer can adversely affect the supply to adjacent customers, AEL does not only requires customers to comply with the New Zealand Electrical Code of Practice for Harmonic Levels, NZECP 36:1993, but has also developed with the help of some other Distribution Companies, a Harmonic Standard that customers are required to comply with. 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.

- Fault Levels

  AEL has 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, etc. In addition, all new switchboards are installed with arch-flash protection schemes.

  AEL is 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 by the suitable choice of transformer impedances and transformer arrangement as the supply transformers are changed at Timaru.

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

- Power Factor

  Power factor is a very important electrical characteristic and needs to be managed responsibly. The closer the power factor is to 1, the more optimal the infrastructure is utilised. AEL is achieving this through its new connections policy and technical requirements for new plant to be connected to the network. Capacitor banks are used on the network to improve voltage levels along loaded feeders 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.

Equipment is selected based on the theoretical and electrical characteristics as outlined in the previous sections. AEL also attempts to standardise as much as possible and in practical terms this translates to the following materials and equipment being specified and used:

A. Subtransmission Lines

As can be seen in section 5.9.5 there are various factors that limit the capacity of sub-transmission. Section 5.9.5 tabulates the differing factors as examined by AEL and indicates the capacity of existing and some proposed works.

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

- 17 m, I beam, Humes ex Gladstone, 12 kN transverse working
- 15 m, Hardwood.

Insulators

AEL is not yet convinced that the new polymer type insulators are the ultimate solution for line build. AEL has 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. It has been noted on some earlier ESP long rods they are aging prematurely. Most polymer surge arrestor housings are aging prematurely.

Pin, bobbin & stay insulators – general range of product from NZI catalogue.

Strain insulators – generally glass disc ex Chinese manufacture for 11 and 33 kV work. Ball and socket ex Sediver or similar about to be adopted for 110 kV work.

Post insulators – 110 kV NZI catalogue insulators about to be adopted for 110 kV work.

Zone Protection

AEL has no Zone protection on its 33 kV overhead lines. New sub transmission will have a form of unit protection if it forms a mesh. AEL's 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 351S or 351R will be applied.

B. Subtransmission Cables

Cable

- 400 mm^2 Al 1C, Al XLPE/HD CWS/MDPE, 11 & 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 & 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. Subtrans to North presently run on 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 subtransmission will have a form of unit protection if it forms a mesh. AEL's 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 subtransmission 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 will be applied.

C. Zone Substations

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

- 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 architechture
- 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.

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

AEL prefers to avoid SF6 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 & 33 kV phase instrument transformers generally from Arteche’s catalogue
- 33 kV, Cooper VWVE38 for sites below 4 kA fault level
- 11 kV, RPS LMVP range of product
- 33 & 11 kV NCT from TWS’s catalogue. Some phase instrument transformers are also purchased from TWS.

The “first of” procurement for evaluation of the following switchgear:

- 33 kV, Schneider Electric GHA
- 11 kV, Nova recloser range of product

Protection

New zone substation transformers will have a form of unit protection, AEL’s 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 or high impedance bus bar protection fitted. Devices like the 311C may be adopted for under impedance relays and 587Z for bus bar protection from the SEL catalogue.

Indoor switch gear may have arc flash detection protection fitted via inputs to the 751A relay from the SEL catalogue.

Auxiliary systems

Each station has a d.c. system of either 24 V or 110 V to supply essential equipment in the case of an a.c. power system failure.

AEL prefers 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.

D. Distribution Lines

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 AEL 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
- 10 to 15 m, Softwood
- 9.7 & 10.7 m, mass reinforced concrete, NetCon

Insulators

- Pin, bobbin & stay insulators– general range of product from NZI catalogue.
- Strain insulators – generally glass disc ex Chinese manufacture.

E. Distribution Cables

Cable

Selection of cable is based on two criteria:

(a) required power flow

(b) fault level presented with applied protection considered

- 400 mm^2 Al 1C, Al 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 10.1 kA 1 sec or 5.8 kA 1 sec earth fault.
- 300 mm^2 Al 1C and 3C, Al 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 10.1 kA 1 sec or 5.8 kA 1 sec earth fault.
- 185 mm^2 Al 3C, Al 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 10.1 kA 1 sec or 5.8 kA 1 sec earth fault.
- 95 mm^2 Al 3C, Al 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 or 5 kA 3 sec phase and earth fault.
- 35 mm^2 Al 1C and 3C, Al XLPE/HD CWS/MDPE, 11 kV, 149 A direct buried vis 120 A at 20% derating or 2.2 MVA at 11 kV. 3.3 kA 1 sec or 1.9 kA 3 sec phase and 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.

F. Distribution Substations – pole mounted

Poles

- 10 to 15 m, Hardwood
- 10 to 15 m, Softwood
- 9.7 & 10.7 m, mass reinforced concrete, NetCon.

Transformer

AEL seeks supply of transformers, up to 2 MVA from NZ manufacturers. Recent work revealed that some Australian models had higher mass than the NZ design, in the larger power ratings they are not suitable for the pole designs.

AEL finds that industrial type transformers above 2 MVA can be economically procured from Australia so on the occasion they are required alternative prices to New Zealand manufacturers are sought.

HV Switchgear

AEL predominately uses 'drop out' style fuses on a single phase basis for pole mounted transformers. These are suitable up to 12.5 kA fault levels.

If the fault level is above 12.5 kA Ring Main Units are used, these have ratings up to about 20 kA.

LV Fusegear

AEL predominately uses 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.

G. Distribution Substations – ground and underground mounted

AEL has avoided establishing underground sites for a number of years. Ideally all new substations will be above ground. While underground substations are convenient for hiding substations from public view and saving on surface real estate, they introduce operational and maintenance issues relating to confined space access. AEL prefers to avoid situations that restrict access, reduce operating and maintenance efficiencies, and introduce additional risk to personnel. Consequently AEL prefers to establish new substations above ground and to programme the raising of underground substations above ground. As a minimum, those components that require the most amount of attention from operators and maintenance crews through the life of the substations. The components that are of particular interest in this regard are the LV switchgear and the 11 kV ringmain switches. The transformers could ,if necessary, remain underground.

AEL avoids 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 etc. This 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.

Sites

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 land 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

AEL prefers the use of citypad then minipad and micro pad style transformers. AEL have not installed covered sites for a number of years.

Transformer

AEL seeks supply of transformers from NZ manufacturers.

RMU Switchgear

AEL has accepted the use of SF6 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 Ringmaster

Where a site is complex, i.e. 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. If there are multiple transformers AEL requires all transformer secondaries to be run isolated from each other. This leads to interlocking systems being required on bus couplers.

AEL’s distribution subs generally have 400 V fuse-link board made up of:

- A “DIN 1” vertical disconnect with solid links, 800 A rated up to 500 kVA, 1600 A for 750 and 1000 kVA.
- A number of DIN 3 vertical disconnect units, normally 630 A rated with fuse elements to suit.

- A 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.

H. Low Voltage Reticulation

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:

- 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.

AEL avoids 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 Prioritisation of Network Developments

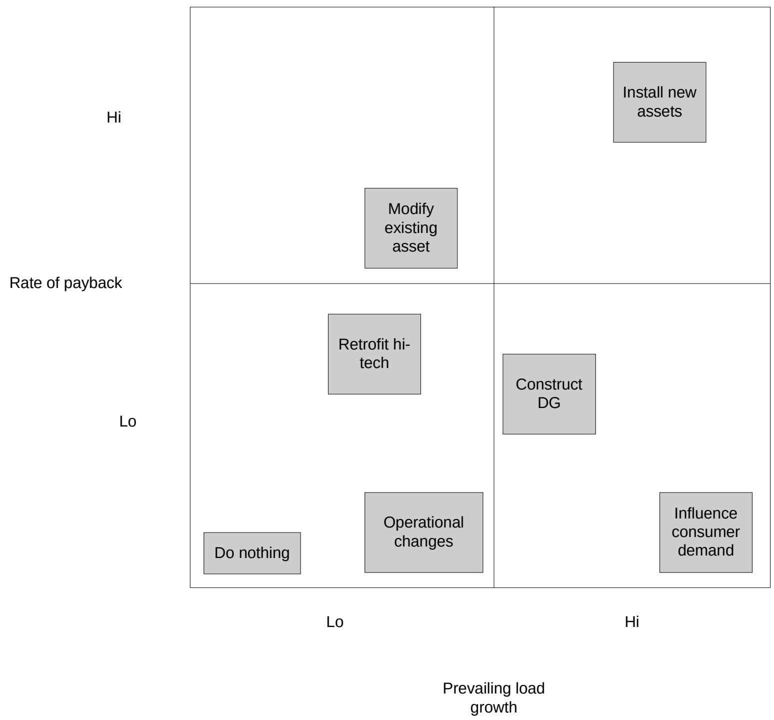
5.2.1 Options for Meeting Demand

Table 5.2 defines the trigger points at which the capacity or configuration of each class of assets needs to be altered. Exactly what is done to increase the capacity or configuration of individual assets within these classes can take the following forms (in a broad order of preference):

- **Do nothing** and 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 AEL. 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**, in particular 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 their consumption patterns so that assets perform at levels below the trigger points. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain 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** so that 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 e.g. water being released from a dam that could be used in a hydro generator, or process steam going to waste.
- **Modify an asset** so that the trigger point will move to a level that is not exceeded e.g. 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** 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** with a greater capacity that 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 AEL considers 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 5.2 is used to broadly guide adoption of various approaches:

▪ ***Figure 5.2: Options for Meeting Demand***



5.2.2 Options for Meeting 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).
- Use of interruptible load (such as water heating) 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".

5.2.2.1 Prevailing Security Standards

The commonly adopted security standard in New Zealand is the EEA Guidelines (June 2000) which reflects the UK standard P2/5 that was developed by the Chief Engineer's Council in the late 1970's. P2/5 is a strictly deterministic standard i.e. it states that "this amount and nature of load will have this level of security" with no consideration of individual circumstances.

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

5.2.2.2 Issues with Deterministic Standards

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

5.2.2.3 Contribution of Local Generation to Security

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

5.2.2.4 Existing Security Standards

Table 5.3 below lists the existing level of security at each zone substation and justifies any shortfall.

- ***Table 5.3: Existing security levels***

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
Timaru	Supply transformers	N-0.85	N-1	Capacity of Transpower's transformer too low, requires load control for security. New transformers requested.
	Timaru CBD	N-1	N-1	Recent completion of new sub-transmission feeders to North Street has confirmed the N-1 security for all periods. N-1 was only available at off peak

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
				periods.
	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 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.
	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.
	Port	N-1	N-1	Work complete establishing two new distribution cables from North St. One ideal for Holcim, or a similar load, should the load eventuate and the second to uptake 1/3 of the Port load.
	TIM 33 kV step up zone substation	N-0.75	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.
	Pareora via 11/33 kV step up zone substation at TIM	N-1 on first 9/15 MVA (Transformer limit), 7 MVA Subtransmission limit to 6% Volt drop N on the remainder that cannot be transferred.	N-1	Capacity headroom investment The transformers have been changed out from 5/6.25 MVA units, and the two 33 kV single circuits PAR-TIM are being re-conductored over five years (2011 to 2015) to gain 10 MVA firm capacity as per Table 5.17. Some load can be transferred to STU and TIM in an emergency.
	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	Pre-used 5/6.25/9 MVA transformer ex RGA being considered for installation at PLP. 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

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
				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.
Temuka	Clandeboye 1 & 2	N-2 (Sub-Trans) N-1 (GXP)	N-2	Customer investment – 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.
	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.
	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.
	Rangitata	N-0.5	N-1	Limited fault backup from GLD and TMK. Second 33 kV line from Canal Rd ready except protection issues at GXP. Second transformer installed to allow first transformer to be removed and replaced with a larger transformer. RGA 11 kV rings strengthened through additional feeders. RGA 11 kV ties to GLD strengthened.
	Geraldine	N-0.5	N-0.5	33 kV investment to be considered. Watch Transpower's proposal for an Orari bussing point. May free a circuit passing near GLD to RGA for use at GLD. GLD 11 kV ties to RGA strengthened

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
				with RGA work.
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.
	NZDL 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.
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.
	Oceania Dairy	Being scoped	Mar 2014	Prospect of feeder to a dairy as a stop gap measure until a permanent supply point can be made, planned to be N security if customer agrees.
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.
	Fairlie	N	N	Limited fault backup. Possibility of 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.
Tekapo	Tekapo CBD	N-0.5	N-1	No alternate supply to station. Limited 11 kV rings. Encourage customers to be self sufficient for their essentials. As for CD

GXP	Zone Sub / Load Centre	Actual	Target	Shortfall from target
				emergencies.
	Mt Cook & 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.
	Lillybank/ Haldon and Balmoral	N	N	Radial lines and zone substations, no backup. Encourage customers to be self sufficient for their essentials. As for CD emergencies.
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 Rural	N	N	Limited fault backup Encourage customers to be self sufficient for their essentials. As for CD emergencies.
Various	Mobile Substation 33/11 kV	Being scoped	End 2014	Mobile Substation being studied for use to back up sole transformer stations to improve their security. For a transformer failure fastest response may be to move a mobile substation onto site and feed the local area.

5.2.3 Choosing the Best Option to Meet Demand

Each of the possible approaches to meeting demand that are outlined in Section 5.2.1 will contribute to strategic objectives in different ways.

Having established that there is significant and persistent growth in demand on a particular part of the Network, and having estimated the future rate and time limit for the growth, AEL applies the following decision and approval process to identify, evaluate, cost, and select options that may satisfy the requirements of the growth in load demand:

a) The Asset Manager and/or Engineers analyse: the characteristics of the existing assets of the part of the Network concerned by the load growth, the nature of the load growth, and the effects the growth will have on the existing assets within the planning period;

b) The Network Manager, Asset Manager and Engineers then collaboratively propose options to respond to the growth, with due regard to relevant criteria defined in the AMP in general and in Section 5.2 of the AMP in particular;

c) The Asset Manager and/or Engineers will then, analyse the benefits and costs of the respective options with due regard to appropriate decision making techniques (e.g. BCA, MCA, risk assessments, and network level optimisation, as appropriate), compare the respective benefits and costs, and recommend the most appropriate option;

d) The Network Manager, with input from the Asset Manager, Engineering, and Operations will include in the works plan to be incorporated in the AMP and budgets for approval by the CEO and Board.

5.2.4 Prioritising Projects within the Plan

Having selected the projects for inclusion in the capital works plan, their relative priorities are set as follows.

1. **Safety:** projects that require execution to improve safety and/or remove hazards. Criteria include: Public safety, workplace safety, and network operating safety;

2. **Reliability:** projects that improve network resilience in the face of faults, undesirable events & general use.

   Criteria include improve network: condition, interoperability, adaptability, flexibility, ease of use, and maintainability;

3. **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;

4. **Economy:** projects that produce the best return in terms of network improvement for funds expended.
   Criteria include minimising the costs relating to impact on: society, business, regulatory, and legal requirements.

The Section 7.1.1 “Risk Criteria” relates to this aspect of capital project prioritization.

5.3 Demand Forecasts

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

The present climate has shown substantial growth in the farming sectors, while the urban sectors: domestic, commercial and small industrial loads, have remained relatively stable since the start of the economic recession in 2008-9. There is confidence that the rural sector will continue its strong growth despite the continuing world recession with further development from the dairy industry and for irrigation.

The past business confidence has directly translated into investment in this sector with large developments occurring in milk treatment facility development, irrigation scheme development and on-farm development by way of dairy shed, pasture irrigation and support infrastructure for staff quarters etc. This has consumed most of AEL's capacity headroom and created the need to reinvest in infrastructure capacity to restore headroom and provide some backup capacity.

By discussing forward planning with industry representatives, AEL 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.

Network modelling is a mathematical planning tool which indicates areas of adequate capacity or areas of constraint in supply from the existing network assets based on present and future loading conditions.

By modelling future load conditions, this provides an analysis of areas which need additional investment to meet new loads predicted from demand forecasts.

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

Recent energy efficiency schemes have seen an uptake of CFL's. It is difficult to measure their direct impact on the network due to the seasonal affects changing load patterns.

On the opposite side of the energy balance equation, regional councils are looking at legislation to phase out open fires to improve air quality, though the 2006 snow storm has damped enthousiasm for this measure. Nevertheless, home owners have been considering other forms of heating and the market has responded with electric heat pump offerings. While an electrically efficient form of heating, it will increase the load on the network. Predictions of a diversified demand of 50% of 2 kW demand from 5,000 homes would introduce an additional 5 MW of peak winter demand onto the network, representing an 8% increase for the Timaru GXP.

Electric Vehicles:

Development of electric vehicle market is increasing rapidly worldwide. Some statistics available on the Internet for a sample of three EU countries show "exponential" growth in new registrations of EV cars (i.e. not including other EVs, such as utilities, quadricycles, etc.) over the last few years:

Country:	Total EV sales:	Sales 2012:	Sales 2011:	Sales 2010:	Sales 2009:	Sales 2008:
France	**7,153**	4,339	2,630	184	-	-
Netherlands	**3,410**	2,520	812	54	24	-
Norway	**6,361**	3,035	2,116	564	254	392
Total od sample:	**16,924**	**9,894**	**5,558**	**802**	**278**	**392**
%age of previous year:		178%	693%	288%	71%	-

(Acknowledgement: These statistics were extracted on 30/01/2013 from a Wikipedia article "Electric car by country", that contained information on 24 countries' up-take of electric cars, including reference to various makes and models).

Note that the above table is indicative only and does NOT includes HEVs (hybrid electric vehicles).

The table indicates a growth rate in sales of EVs that is variable, suggesting an "S" curve, but it is probably too early in the development of the commercial market for affordable electric cars to draw any conclusions as to long term growth rates.

The NZ Market for Electric Cars:

Some commentators have suggested that once EVs become readily available in NZ the up-take of EVs is likely to be of the order of 2% per annum of the national fleet of cars. This would mean that it would take approximately 50 years to replace the existing fleet.

It is interesting to note that the number of new conventionally fuelled (petrol, diesel) vehicles entering the NZ light fleet in 2011 was about 80,000 per year according to Ministry of Transport figures. The Ministry's 2011 report does not list EVs or Hybrids.

Referring to the table above, the French fleet in 2012 had **4,339 EV** vehicles entering its national fleet. However, in 2011 France had **2,630,883 conventionally** fuelled light vehicles entering its vehicle fleet. That is **EVs only** made up **0.165%** of the **total** new entries into the French fleet, a very small number. So it is far too early to be predicting trends for the take-up of EVs.

However, on the assumption that the trend may grow to a significant figure sometime in the near future, it is instructive to perhaps consider the following statistics:

NZ Vehicle Statistics and the Effect of EVs Entering the Fleet:

The Ministry of Transport's March 2012 "The New Zealand Vehicle Fleet – Annual Fleet Statistics 2011" states that the light fleet (including light passenger and light commercial vehicles, under 3.5 tonnes) makes up over 90% of the total vehicle fleet. The light fleet size has been relatively stable at just under 3 million vehicles since 2007. Also since 2007, the light fleet total annual travel kms has been stable at about 37 billion vehicle km per year. The average per capita annual kms have decreased since 2007 from about 8800 km/year to 8300 km/year despite the increase in the population in that period. The average annual km per light fleet vehicle has dropped from about 12,500 km per vehicle per year in 2007 to about 12,250 km per vehicle per year. The estimate of light fleet petrol fuel economy (on-road) have dropped from about 10.3 Litres per 100 km of travel in 2007 to about 10.1 Litres per 100 km of travel in 2011.

CO2 emissions in 2011 from all vehicles included 65.2% due to light fleet vehicles. (The Ministry's Report notes that **CO2** emissions are in direct proportion to the amount of fuel used, and not to be confused with engineered solutions to reduce **harmful** emissions).

Increase in Domestic Electricity Demand due to an EV:

Charging an EV in NZ is equivalent to buying petrol at about 26 cents per litre (EECA estimate).

Assuming a worst case charging regime of: 8 hours charge at 230 V, 15 A, gives a MD of 3.45 kW and a power requirement of 27.6 kWh for a range of say 100 km (probably more).

If the take-up rate is 2 % of the total light vehicle fleet of 3 million vehicles, then annual growth in EVs would be 60,000 vehicles added per year (compared with the 2011 new light vehicle annual registrations of about 80,000 per year, but not including imported used light vehicles of about the same number).

If the 37 billion vehicle km per year are evenly distributed over the entire light vehicle fleet, regardless of EV or petrol vehicle, then average km per EV is 12,333 km/year.

Thus the average electricity consumption per year per EV would be 3,404 kWh per EV per year.

Effects of EVs on the Electricity Network, USA Experience:

The USA has experience of the Ford Explorer hybrid vehicle needing 16 kWh to charge over a period of 2 hours to 8 hours. It has been found that these get connected in clusters as the neighbourhood “keeping up with the Jones’” occurs. The GM Volt suggests a full charge of 16 kWh over an 8 hour period. This sort of load is similar to the standard electric hot water heating element.

Estimate of Possible Load Growth Due to EVs:

AEL is watching with interest the work of the University of Canterbury EPE Centre and their review of how the introduction of the electric vehicle may impact on New Zealand. Say 2 kW demand is taken for 2000 vehicles over the next ten years, an introduction of an additional 4 MW of unseasonal peak demand onto the network will occur, representing an approximate 4% increase for the AEL GXP’s if proportionally spread.

However, if the rate of take-up of EV’s is similar to France (i.e. 0.165%, see above) but increasing by the same amount each year, then we might assume an uptake each year of 80,000 x 0.00165 x n, with n = 1 in 2013 and increasing linearly to 11 by 2023. The accumulated EV population across NZ by the end of 2023 would then be 8712 EVs. Then the population of EVs in South Canterbury after 10 years might be: 8,712 x 54,000 / 4,000,000 = 118. So, on this basis, EVs are not likely to be a problem for AEL.

Not a problem that is, unless all 118 EVs were being charged within the same suburb. Assuming an EV MD of 3.45 kVA per vehicle, and all 48 consumers per 300 kVA distribution transformer own one EV each, then the additional MD per transformer would be 166 kVA. Typically each 330 kVA transformer would be loaded to about 200 kVA MD. Thus, in this scenario, the two or three distribution substations would need to have their transformer upgraded from 300 kVA to 500 kVA, at a minimum. The other concern is the capacity of the AEL 230/400 V cables between the transformer and the 48 consumers – these LV cables may require to be upgraded to cope with the increased MD likely to be experienced on winter evenings, particularly around meal times.

PV and EV may combine to force Distribution Sub and LV Cable upgrades:

Of course there may be another reason for upgrading the transformers and LV cables in affluent suburbs – the expected uptake of Photo Voltaic distributed generation as the price of PV arrays and inverters fall and their availability increases.

Therefore, over the AMP planning period, AEL must monitor the progress of the take-up 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.

Demand Forecasts:

Demand forecasts are derived from reviewing the historic base load position from SCADA information which indicates a base line trend. From this base line an analysis of requested load connections are processed to determine if these support the trend, are lower than the trend or exceed the base line trend details. Added to this assessment are known step load demands. The step load demands are usually one off connections of larger capacity and may occur due to a new commercial business which will encourage or support further development of the baseline trend.

Once this planning has been completed and an understanding is gained, this is compared with network modelling to compare existing network load performance against the forecast demand trend. The model will then indicate areas of constraint which leads to decisions on how to augment the network to accommodate the demand forecast or return capacity headroom in a network constraint area.

5.3.1 Present Demand

The following Figures 5.3(a), (b), and (c) present the historic half hourly demand per GXP over the last 15 years from 1997 to 2012 These curves indicate the Total AEL and Maximum Demand growth rate for each GXP (shown by the dotted trend line in each case):

Figure 5.3(a) below shows the 15 year growth rate (blue dotted line) as well as and the growth rate over the last four years (pink dotted line). Over the last four years the growth seems to have stagnated, which can be attributed to the international financial crises of 2008 and its effects on development and the business climate in New Zealand. The Christchurch earth quake in September 2010 and February 2011 has extended the recovery of the economy in South Canterbury.

AEL does not expect the load growth to remain flat for very much longer. The indications are there that growth will resume although perhaps not at the same levels as before. The slow down in the growth has however bought some time to complete necessary network upgrades, maintenance and new capital projects required to sustain future growth.

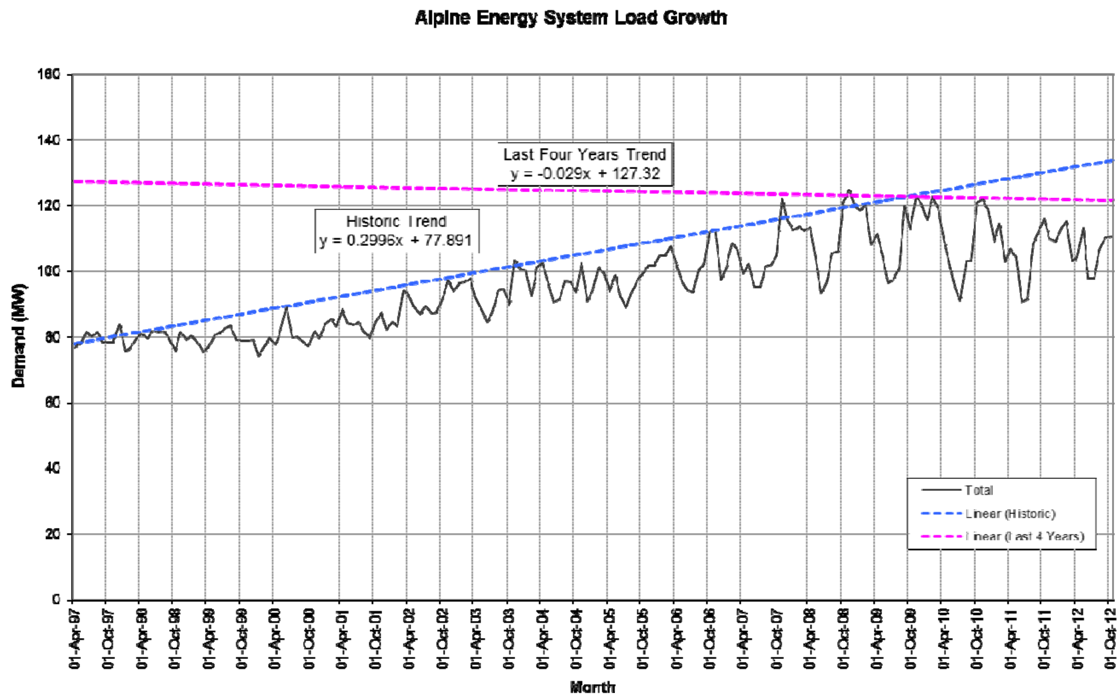


Figure 5.3(a): AEL Total Load Growth

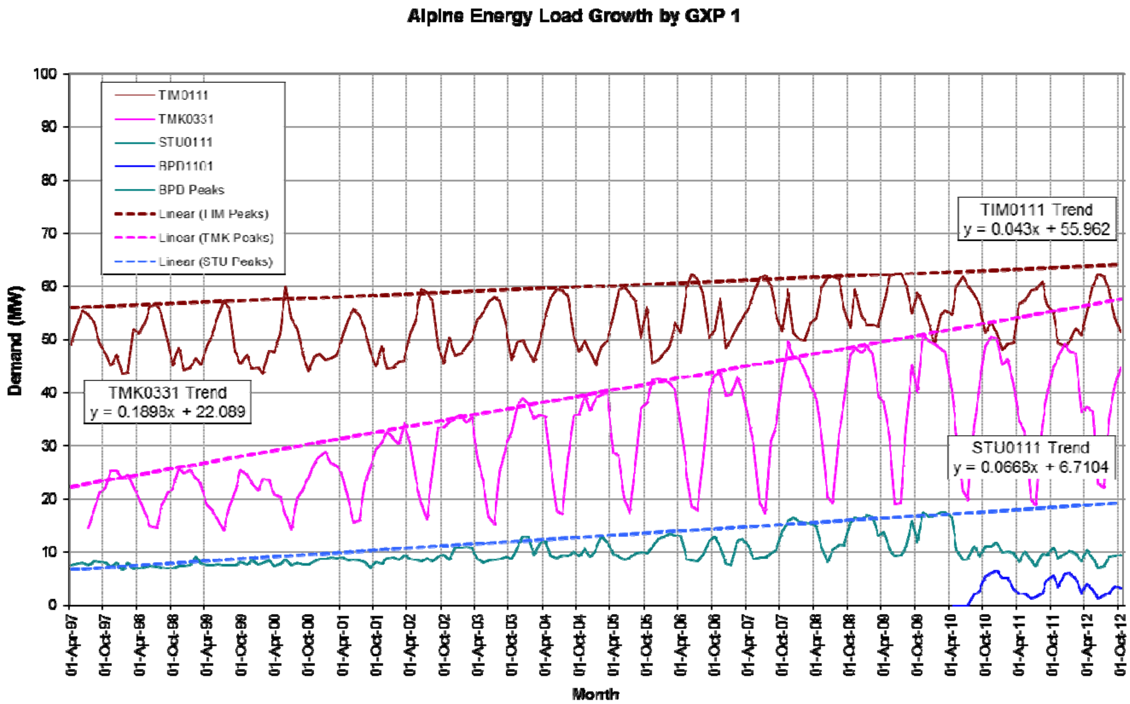


Figure 5.3(b): Load Growth by GXP 1

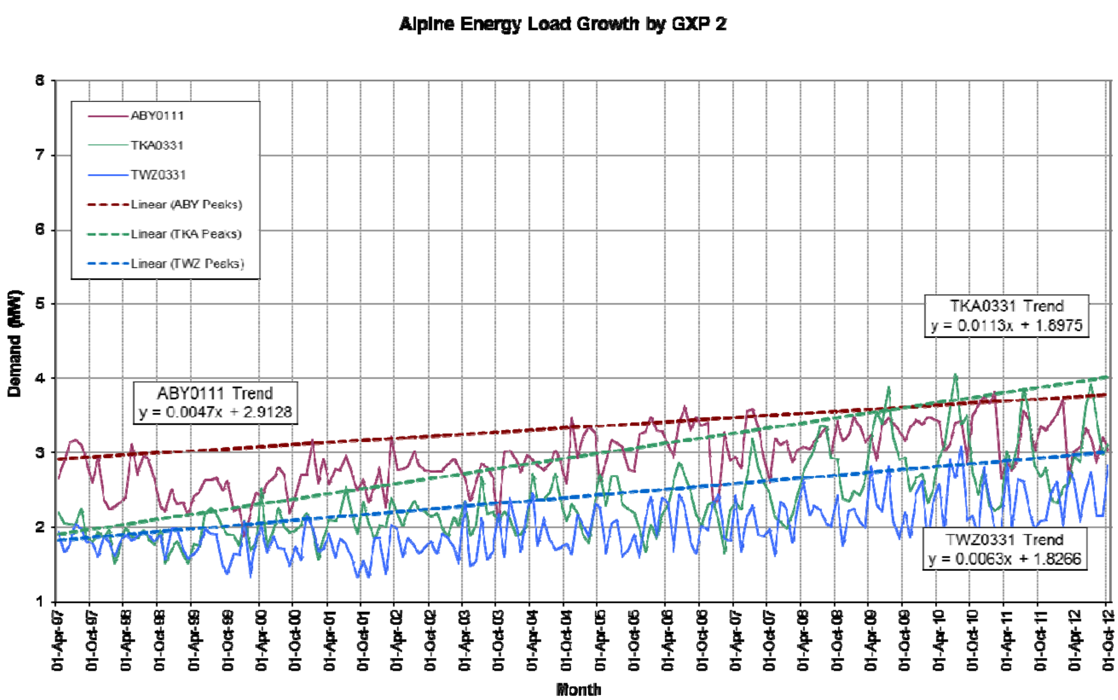


Figure 5.3(c): Load Growth by GXP 2

From the above graphs, Table 5.5 below contains the historic demand growth rates for the GXP's listed.

- ***Table 5.5: Historic GXP Demand Growth***

GXP	**½ hr MD (MW)**	**MW Growth / Month**	**MW Growth / Annum**	**% Growth**
ABY0111	4.18	0.0047	0.0564	1.35
STU0111	10.39	0.0668	0.802	7.72
BPD1101	6.07	0.0298	0.358	5.89
TIM0111	62.22	0.043	0.516	0.83
TKA0331	3.92	0.0113	0.136	3.46
TMK0331	47.71	0.1898	2.278	4.77
TWZ0331	2.83	0.0063	0.072	2.54
Total	**137**	**0.351**	**4.217**	**3.071**

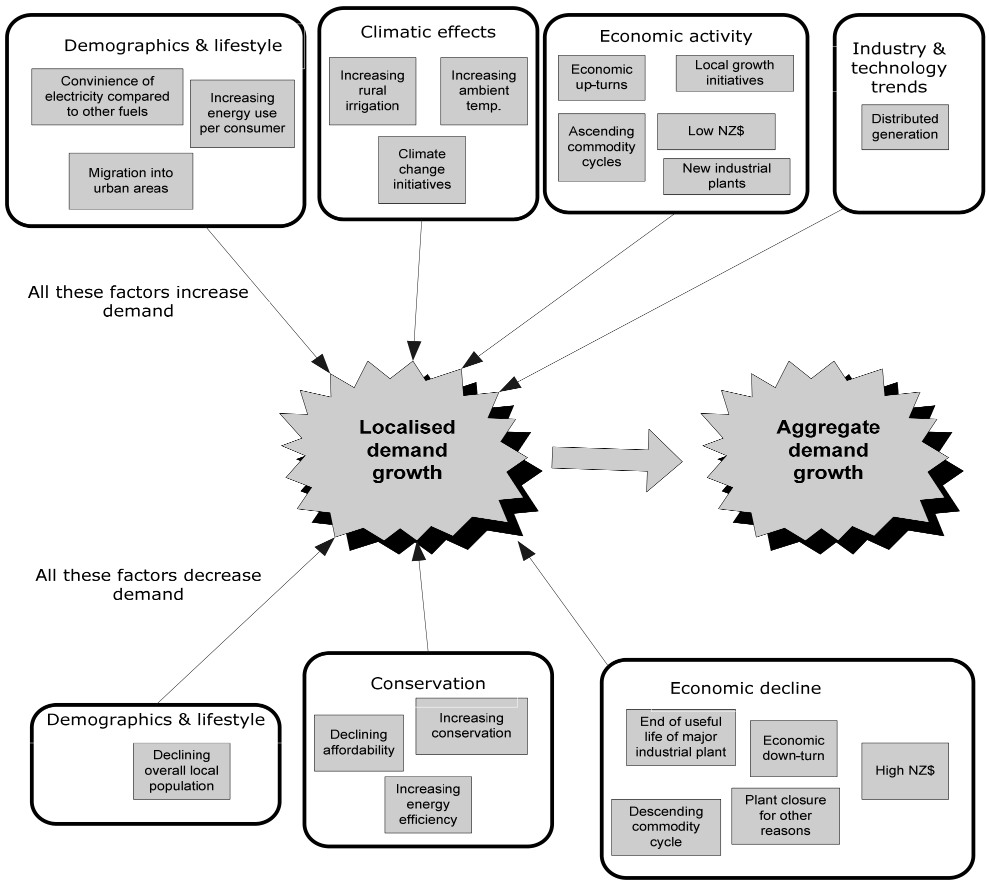
Note: The above numbers are current to November 2012 and are based on single half hour maximum rather than average of twelve highest peaks. The trend is also taken over the last fifteen years (1997 to 2012).

Note: The STU and BPD load growth is based on the combined load growth prior to the off-loading of STU onto BPD (in late 2010 when BPD was commissioned), apportioned pro-rata based on MD of each to the sum.

The percentage growth is the slope of the linear function obtained from the peaks of the half hourly maximum demand at each GXP. The third and fourth columns in Table 5.5 list the slope of the linear function in terms of MW growth per month and per annum respectively.

5.3.2 Drivers of Future Demand

Key drivers of demand growth (and contraction) are likely to include the issues depicted in Figure5.4 below.



▪ *Figure 5.4: Drivers of Demand*

At residential and light commercial feeder level, 3 or 4 of these issues may predominate and be predictable and manageable on a statistical basis however, AEL's experience is that large customers give little if any warning of increases or decreases in demand due to commercial sensitivity.

The residential and light commercial demand projections can be aggregated into a reasonably reliable zone substation demand forecast but heavy industrial demand will always remain a big unknown. AEL's estimates of future demand are described in section 5.3.3 below.

5.3.3 GXP Substation demand growth rates

The GXP Substation demand growth rates are presented in a series of tables and graphs, (one table and graph) for each existing GXP substation's area. The current and planned security at each GXP (i.e. N and N-1) is also depicted in some figures.

AEL expects its demand to increase as detailed in Table 5.5, and on the following basis and assumptions:

- There will be no significant shifts in the underlying technology of electricity distribution in the next 5-10 years. (Refer to Section 5.5.2 for discussion on Demand Side Management)
- 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 1-2% per year.
- Areas with summer peak demand substations (Bell's Pond, Clandeboye, Studholme, Temuka, and now Albury) will have commercial new connections driven by Dairy, Crop and Irrigation developments and are likely to remain strong for the planning period and increase at an average rate of 3% per year depending on weather conditions. (i.e. wet summer will curtail irrigation, however a drought will result in total installed demand being operated).
- Diversity across each zone substation is assumed to be constant through the forecast period.
- Constant load power factor throughout forecast period and is set at the average for the winter period on each GXP.
- All demand forecasts will be reviewed annually.

The following step demands loads are possible at the time of AMP review and included in the planning process:

- *Table 5.6: Projects Adding Step Demand Increases - by GXP*

Project	Demand (MW)	Year	GXP
Ecotech plastics	0.8	2013 Plant installed – load not yet realised)	Timaru
TDC Milliscreen	0.25	2013	Timaru
Washdyke Flour Mill	0.5	2013	Timaru
Washdyke Salmon factory	0.25	2013	Timaru
By Products Stage 3	0.55	2013	Timaru
Rangitata Irrigation	3.0	2013	Temuka
Hydro Grand	0.5	2014	Timaru
Oceana Dairy Ltd	5.86	2014	Bell's Pond then transfer

Project	Demand (MW)	Year	GXP
Stage 1			to Cooneys Road
Tekapo Village Development	1.0	2014	Tekapo
Studholme Stage 2	3.0	2015	Studholme
Irrigation Pukaki	2.5	2015	Twizel
Irrigation OHC	0.8	2015	Twizel
Irrigation Haldon	0.5	2015	Twizel
Ivey Irrigation	0.2	2015	Twizel
Holcim Cement	1.5	2015	Timaru
Oceana Dairy Ltd Stage 2	3.84	2017	Cooneys Road
Waihoa Downs Irrigation	10.0	2017	Bell's Pond
North Bank Tunnel *	8 ?	2018 ?	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	0.4	2023	AEL

*Note *: Meridian has announced (17th January 2013) that it has placed the North Bank Tunnel hydro power scheme on hold indefinitely.*

The above assumptions and anticipated load growth is incorporated in the load growth projections at the various GXPs as listed in the following sub-paragraphs.

Note regarding Photo Voltaic Local Distributed Generation:

While the growth of PV local distributedgeneration may eventually reduce the flow of energy (in MWh) from the hydro stations into the AEL network during daylight hours, PV will not reduce evening (particularly in winter) in-flows (ignoring the possibility of locally stored energy). GXP and Zone Substation MDs (in MW) 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 GXPs, local Transpower Transmission and via AEL 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.

The definitions of the following terms as used in the diagrams are as follows:

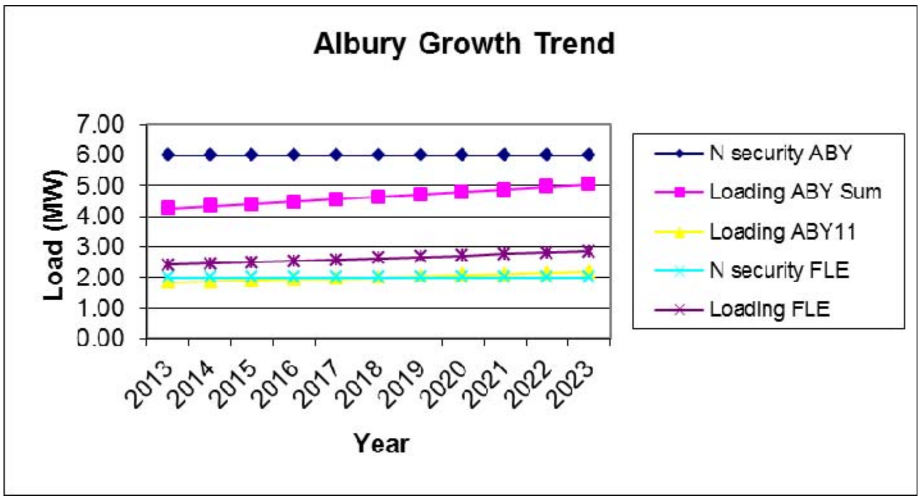
- N security level:- the security level at which any outage will cause load to be tripped, and is often found where there is only one supply circuit or transformer that provides supply
- N-0.5 security level:- the security level at which any outage will cause some load to not be supplied after ties are made to other sub stations
- N-1 security level:- the security level that ensures supply under a single contingency event

5.3.3.1 Albury Substation

Albury GXP calculated load growth is 1.74%. 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 5.7: Albury Substation Load Growth*

GXP Substation (Season Peak)	Growth Trend (Total MW MD) Year 20xx										
	13	14	15	16	17	18	19	20	21	22	23
Albury (Summer)	4.3	4.3	4.4	4.5	4.6	4.6	4.7	4.8	4.87	4.96	5.04



▪ *Figure 5.5: Albury Growth Trend & Supply Security*

Transpower's new 11 kV switchboard is well settled after the August 2011 change out.

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.

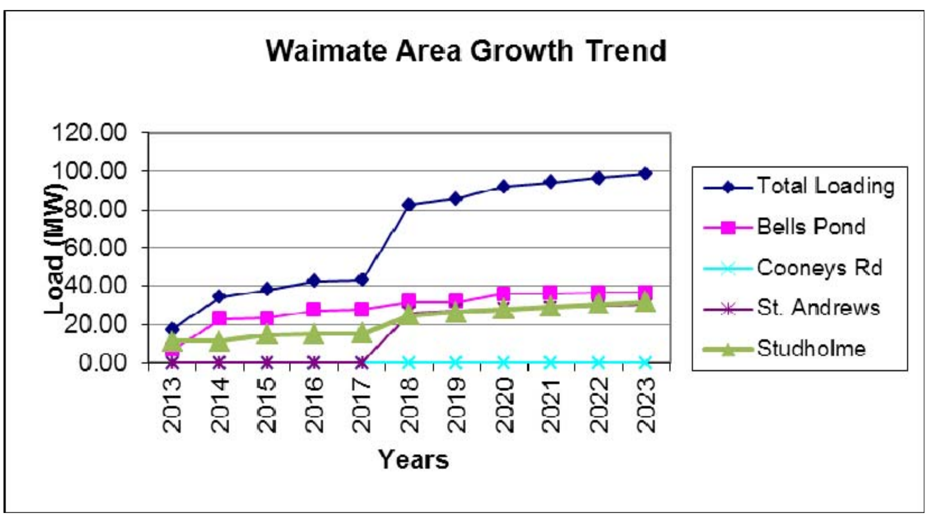
5.3.3.2 Waimate Area

The Waimate area consists of the areas supplied by Studholme and Bell's Pond. When the larger irrigation projects progress it is foreseen that a new GXP will be required at St. Andrews and work done at Bell's Pond if other developments do not see this done in the meantime.

With NZDL 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.

▪ *Table 5.8: Waimate Area Load Growth*

GXP Substation (Season Peak)	Growth Trend (Total MW MD) Year 20xx										
	13	14	15	16	17	18	19	20	21	22	23
Bell's Pond	6.4	22.8	23.2	27.3	27.5	31.6	31.8	36.0	36.2	36.4	36.6
Cooneys Rd (potentially off BPD – included in BPD)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
St. Andrews	0.0	0.0	0.0	0.0	0.0	26.0	27.2	28.0	28.8	29.5	30.2
Studholme (Summer)	11.2	11.4	14.7	15.1	15.5	24.8	26.5	27.9	29.3	30.5	31.7

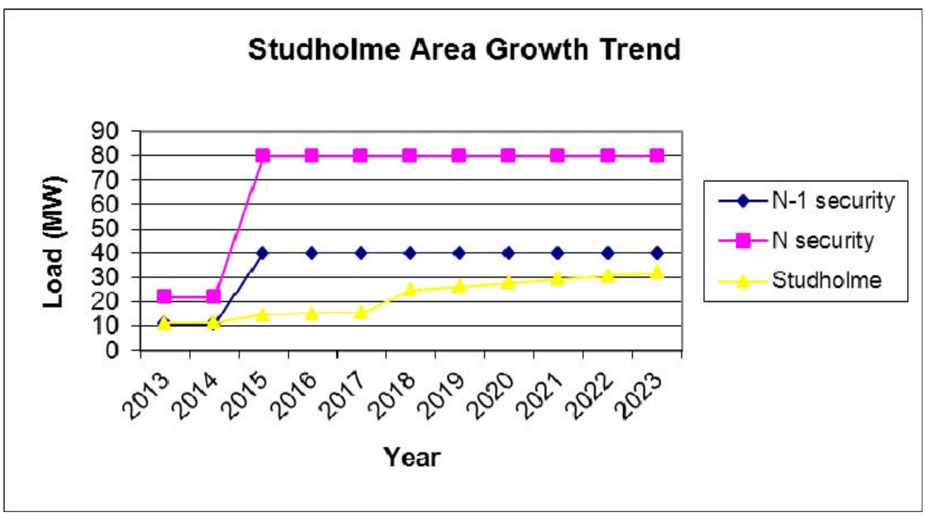


▪ *Figure 5.6: Waimate Area Load Growth*

The load growth is the result of large irrigation schemes being introduced. There is uncertainty about the on-going dairy factory growth. NZDL has been sold to Fonterra, Alpine have requested a meeting to discuss the site's future, when activity subsides at Darfield Fonterra will meet. We have assumed a potential second drier drawing 3 MW for 2015 in the meantime.

Studholme 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. Current 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. Irrespective, Studholme still just breaches the 12 MW N-1 security rating and with the expected 4.72% load growth in the area by 2013, the security risk at Studholme is still not resolved. A second transformer at Bell's Pond connected to the second 110 kV line would remove the present need for Studholme to back-up the Bell's Pond load. The rating of the Studholme board at 24 MVA would then be sufficient throughout this planning period and only an upgrade in transformers would be required. A new GXP at St. Andrews would further unload Studholme and ensure that the current switch board with bigger transformers will suffice for this planning period.



- ***Figure 5.7: Studholme Area Load Growth & Supply Security***

Figure 5.7 shows 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.

New transformers for Studholme are taken as 40 MW as these are practically sized to suit standard 11 kV switchgear (i.e. 48 MVA practical limit on CBs). Their introduction timing is load dependant and needs to be scheduled with other Transpower work.

5.3.3.3 Bell's Pond Substation

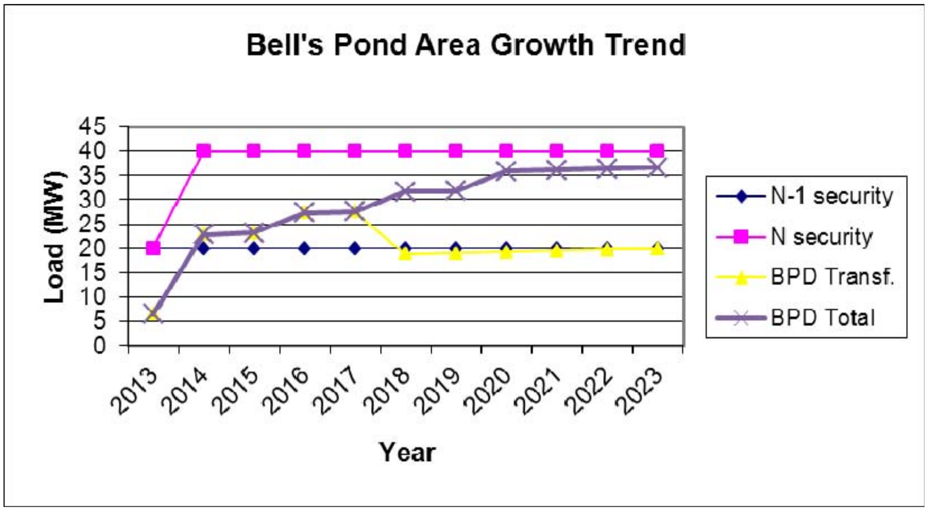


Figure 5.8: Bell's Pond Area Load Growth & Supply Security

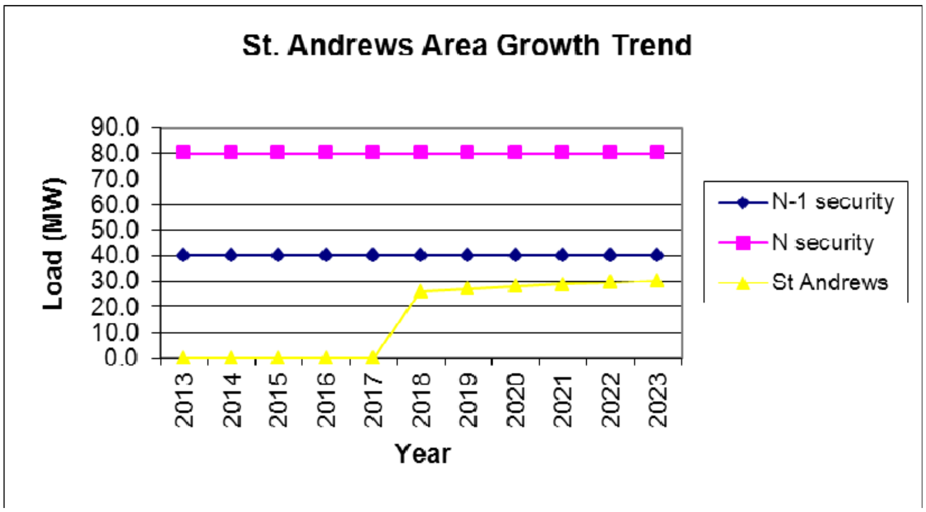
Figure 5.8 above shows Bell's Pond load growth. A second 20 MVA transformer will be required for the site to increase the N transformer security to 40 MVA. AEL would prefer this second transformer be supplied off the alternative 110 kV feeder (also supplying Black Point), this option is still under review by Transpower. This is to accommodate any new project in the area.

In early 2012, enquiries were made 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. The 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 Forks 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, we have tentatively moved it to 2017.

Recently interest in the Oceania Diary prospect has risen again. The time frame required to establish supply to this prospect is very short, it is doubtful a permanent GXP can be created in the time allowed. It is viable to establish a temporary supply off the 33 kV winding at Bell's Pond and supply the initial two stages of the dairy factory. As the factory grows a permanent GXP would be required. In the meantime a second 110/33/11 kV transformer and 33 kV bus assets would be required to be established for this project. We consider that if the diary proceeds this will be needed in late 2014.

In the event of a failure of the single Bell's Pond transformer, some of the load would be able to be transferred to Studholme. A lot of the load is irrigation so it should be able to be cycled. Studholme load transfer is the perceived security for some of the load.

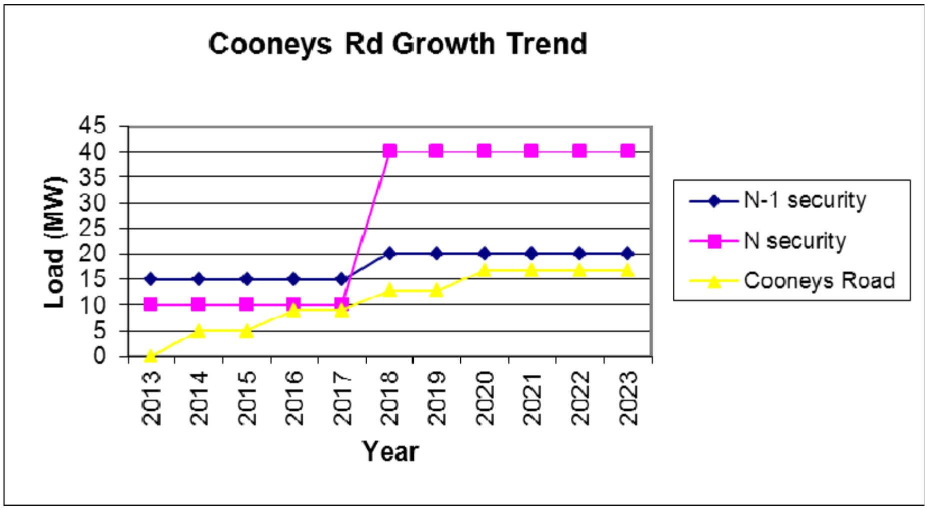
There was a proposed 8 MW additional load in 2018 which would have fallen away in 2022 for the temporary installation of a boring machine for Meridian's proposed North Bank Tunnel hydro station project. This project was in the feasibility study phase but has since been put on hold indefinitely by Meridian in January 2013. AEL would have looked to negotiate an interruption agreement for this supply. This load would also have been required to be fed from the 33 kV bus.



- ***Figure 5.9: St. Andrews Area Load Growth & Supply Security***

Figure 5.9 above shows the expected St. Andrews load growth. Two 40 MVA transformers will be required for the site.

The above is based on preliminary information from a potential irrigation development. Of the options being considered, one option may place a 15 MW demand in the Makikihi area, as well as between 10 and 20, 1 MW canal pumps. For now the St. Andrews/Makikihi GXP is shown as being Transpower's care needing a New Investment Agreement (NIA).



▪ ***Figure 5.10: Cooneys Rd/Oceania Dairy Factory Load Growth & Supply Security***

Figure 5.9 above shows the expected Oceania Dairy load growth. Two 20 MVA transformers would be required for the site, this being the smallest economic size. Before a purchasing decision was made, confirmation regarding sizing would be obtained with Oceania.

The above is based on preliminary information from the potential dairy development. For now a 110 kV GXP is assumed to be established at Glenavy with two transformer feeders making supply to Cooneys Rd some 5 km away. This would replace the temporary AEL 33/11 kV substation referred to above.

Glenavy is Transpower's care needing a New Investment Agreement (NIA). Cooney's Rd will be established with a new connection agreement between AEL and Oceania.

5.3.3.4 Tekapo Substation

▪ ***Table 5.9: Tekapo Substation Load Growth***

GXP Substation (Season Peak)	Growth Trend (Total MW MD) Year 20xx									
	13	14	15	16	17	18	19	20	21	22
Tekapo Sum (Autumn/Spring)	3.9	5.1	5.2	5.4	5.6	5.8	6.0	6.2	6.4	6.6
TEK Village	2.6	3.7	3.8	3.9	4.1	4.2	4.3	4.5	4.6	4.8
Mt Cook	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8

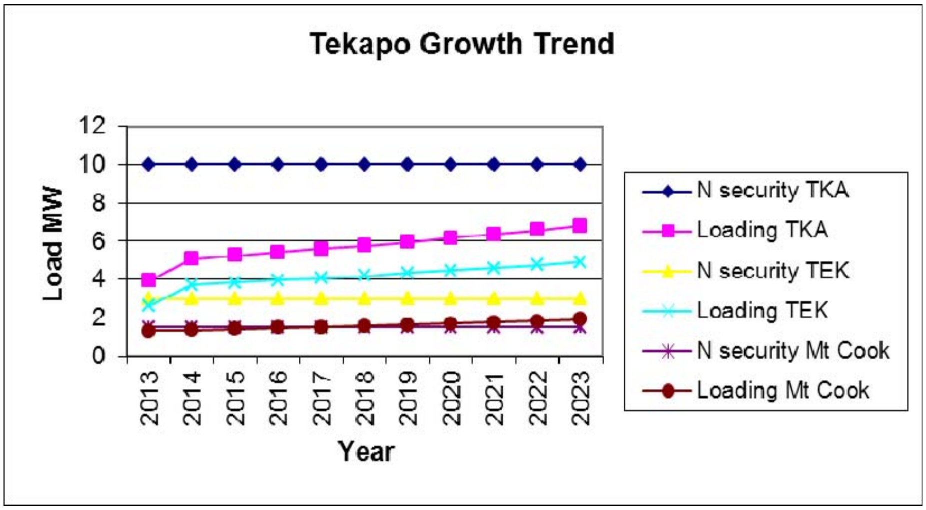


Figure 5.10: Tekapo Load Growth & Supply Security

Based on the maximum demand history to date the almost six percent load growth anticipated in the tourism sector in 2009, has fallen back to nearer 3.5% looking into the immediate future. There appears to be a halt to the proposed CBD development due to the economic recession. It is assumed that this will recommence in 2014.

Meridian looked to move the 11 kV board at Tekapo A station which would have provided a good opportunity for AEL to gain a second supply (security) and have a bus coupler to allow separation of the grid from the generation so that if one failed AEL would still have supply. However, Transpower have decided to retain the existing switchroom which would not allow for the additional circuit breakers in the specific configuration AEL want in order to improve reliability.

A bus fault would result in a total supply loss until repairs were effected. AEL is also supplied from an 11 kV to 33 kV step up transformer. Since the spare 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.

5.3.3.5 Temuka Area

Table 5.10: Temuka Substation

GXP Substation (Season Peak)	Growth Trend (Total MW MD) Year 20xx									
	13	14	15	16	17	18	19	20	21	22
Temuka (Summer)	50.2	56.5	57.9	59.3	60.8	62.3	63.9	71.5	73.3	75.1

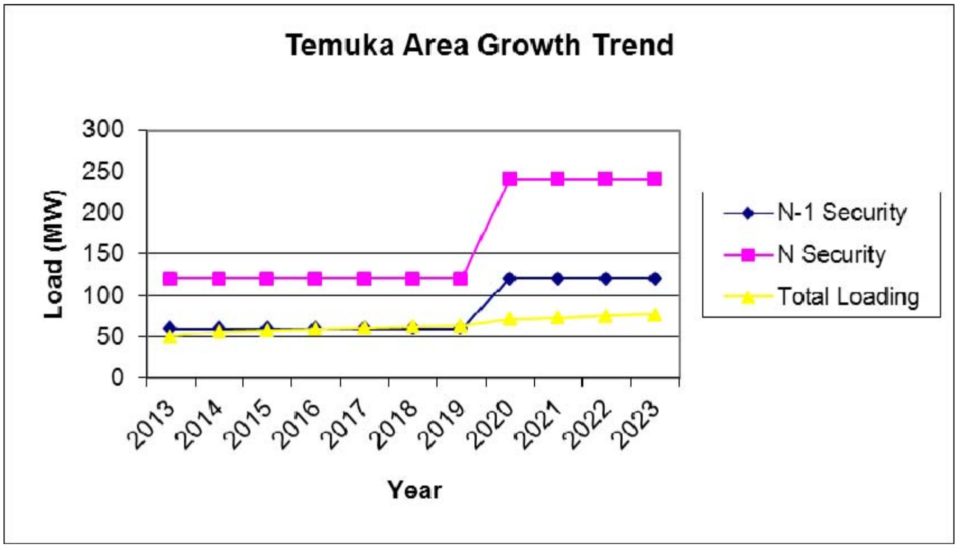


Figure 5.11: Temuka Area Load Growth & Supply Security

The above trend shows that the Temuka 33 kV GXP load will match the secure supply capacity until 2019. AEL hopes for an introduction of a new 33 kV GXP at Orari or an increase in the potential of the transformer feeders to say Clandeboye. This is dependent on Transpower carrying out their bussing project.

Fonterra has advised that the new drier (D4) is on hold pending developments at the Darfield plant. AEL has however factored in additional load around 2021 for expansion at Clandeboye. 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.

Transpower has included a possible upgrade in their planning report to install one 120 MVA transformer at Temuka. This would best be done onto a new two bus-section 33 kV switchboard with the existing two transformers "bolted" together (120 MVA) to supply the other side of the switchboard.

If the transformers are upgraded, a new 33 kV switchboard will be required as the existing one is only rated to 71 MVA.

Cascading off this switchboard via a couple of feeder circuit breakers will be the existing switchboard, its incomers connecting to the new feeders. A couple of the higher loaded feeders would be transferred to the new board.

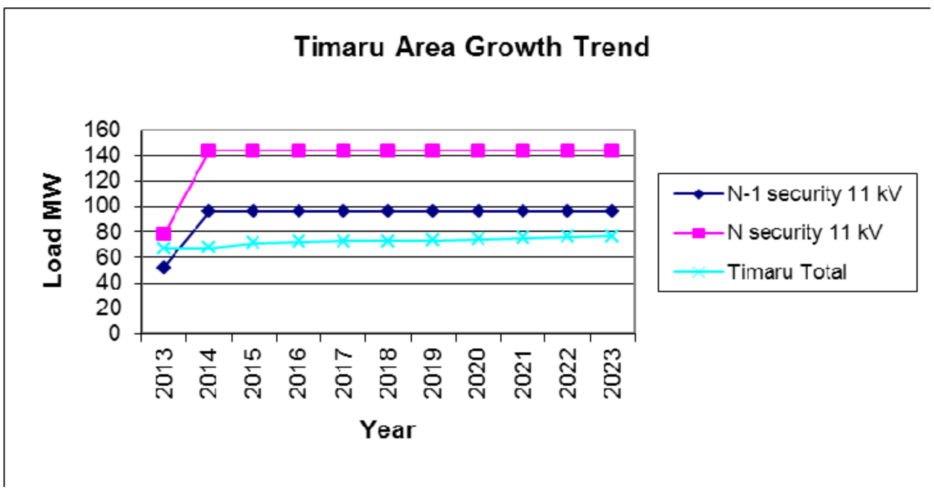
The 110 kV lines to Temuka from Timaru are rated 70 MVA, with either some lifting to provide better ground clearance or re-conductoring, they could be rerated to allow more power flow.

Transpower has also identified the need to upgrade these lines to supply the new transformer arrangement at Temuka.

5.3.3.6 Timaru Substation

▪ *Table 5.11: Timaru Substation Load Growth*

GXP Substation (Season Peak)	Growth Trend (Total MW MD) Year 20xx									
	13	14	15	16	17	18	19	20	21	22
Timaru 11 kV (Winter)	67.1	67.9	71.6	72.3	73.0	72.8	73.6	74.4	75.2	76.1



▪ *Figure 5.12: Timaru Area Load Growth & Supply Security*

The above trend shows that the Timaru 11 kV GXP has become overloaded, with the existing 110/11 kV transformers.

The 11 kV switch board was replaced in early 2012. The new board has been arranged to suit AEL's 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 until a significant load growth is realised to justify the introduction of a 33 kV GXP.

Transpower are planning to change their three single phase 110/11 kV bank arrangements for three 40 MVA three phase units in 2015/16. AEL has asked that two are used to supply load while the third is on hot standby. This is to allow a significant lowering of the multiphase fault level in the

11 kV network. With 80 MVA of transformer capacity available N security could be maintained past this planning period. This would delay the need to introduce of a 33 kV GXP.

An initial Solution Study Report (SSR) was undertaken by Transpower which promoted a 220/33 kV GXP to extend the useful life of the 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 Timaru, Temuka, Albury and Tekapo A. On occasion additional load is required to be supplied south to Studholme and Oamaru. During the dairy season Studholme is tied through. A tripping of the Waitaki feed into Studholme could lead to the interconnectors combined load being taken beyond their 120 MVA individual rating. Transpower has conducted a recent stakeholders forum hosted by AEL to investigate possible non transmission solutions (NTS) and to share the list of possible solutions, both NTS and grid upgrade, with stakeholders to comment on.

AEL has had requests that load has to be limited through the interconnectors during some maintenance periods on Tekapo A generation. This is an uncomfortable position.

5.3.3.7 Twizel Substation

Note: The 20 MVA firm capacity is shared with Meridian Energy and Network Waitaki.

- ***Table 5.12: Twizel Substation Load Growth***

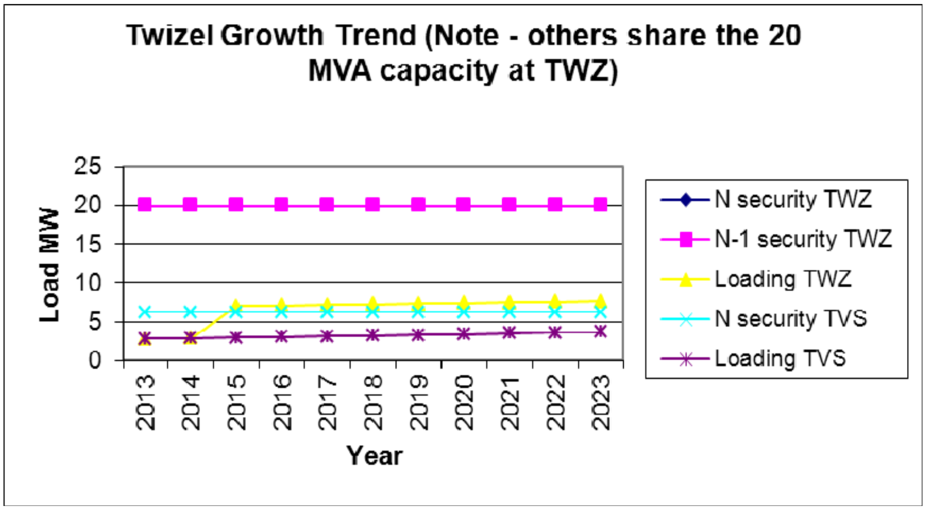
GXP Substation (Season Peak)	Growth Trend (Total MW MD) Year 20xx									
	13	14	15	16	17	18	19	20	21	22
Twizel (Autumn/Spring)	2.8	2.8	6.9	7.0	7.1	7.2	7.2	7.3	7.4	7.5
Twizel Village Sub	2.8	2.9	3.0	3.1	3.1	3.2	3.3	3.4	3.5	3.6
Irrigation on 33 kV	0.0	0.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0

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 2015. 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.



▪ *Figure 5.13: Twizel Load Growth & Supply Security*

Presently the substation land is owned by another party, discussion over future land use will need to be undertaken to shore up AEL's on-going need for the site.

5.3.3.8 Effect of GXP Forecast Loads on 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.

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. If irrigation growth occurs in the Totara Valley area the load capacity headroom on this transformer will be eroded if not consumed.

Studholme is currently just managing to fall within an "N-1" security GXP, however with any new dairy factory load or increase in irrigation load, this security level will reduce to "N" and require upgrading to N-1 security with larger capacity transformers. Discussions with Transpower are underway. There is also significant dairy and irrigation load in this area. A 40 MW irrigation scheme is proposed for development over the next 5-8 years with Resource Consents for water rights approved. This load step will drive development of a new GXP in the St. Andrews area (South West corner of AEL's supply area).

Temuka's spare capacity is being eroded with the introduction of the South Rangitata irrigation scheme. There will not be sufficient capacity for a large development to occur. More recent irrigation to be introduced is being arranged to be able to be shed in the case of an emergency via ripple plant. Options are being considered with the introduction of Transpower's 220 kV switching bus at Orari with a possible 110 kV feed to Temuka to augment the Timaru 110 kV lines. Another option is for a possible GXP to be established at a large dairy factory to off load the Timaru 220/110 kV interconnectors, the Temuka-Timaru 110 kV lines, the Temuka 110/33 kV supply transformers and Temuka 33 kV switchboard. The new GXP could supply at least 40 MW at the time of commissioning being the local dairy factory and AEL's Rangitata zone substation.

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.

The Tekapo supply is made via a step up transformer from the 11 kV generation bus, then a single supply to the village sub and Mt Cook. Discussions with Transpower are underway for the possible expansion of the 11 kV bus at Tekapo that could increase security of supply to the village substation via two 11 kV cables. AEL would step up to 33 kV for the supply to Mt Cook at the village substation.

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.

Collective experience strongly indicates that it would be rare to ever get more than a few months confirmation (sufficient to justify significant investment) of definite changes in an existing or new major consumer's demand. This is because most of these consumers operate in fast-moving consumer markets and often make capital investment decisions quickly themselves, and they generally keep such decisions confidential until the latest possible moment.

This has a large impact on network asset planning and as a result, while some capacity solutions may be provided within a short time frame, others may take a number of years to be realised. Also, it may take a similar period for the network to respond to providing an adequate level of supply security.

Table 5.15: Rate & Nature of GXP Growth & Provisions made

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

5.3.3.9 Issues Arising from Estimated Demand

The significant issues arising from the estimated demand in section 5.3.3 are.

- Reinforcement of capacity and security at GXP level will involve large assets replacement with pass through transmission costs to customers.
- Increasing air-conditioner load likely to over-lap peak periods
- Requirement to maintain ripple control services to ensure peak demand control is available to maximise load curtailment at peak times.
- These load increases will be harmonic producing inductive rather than resistive in nature which could result in the heating of transformers and cables. Some consumer equipment is also sensitive to harmonics on the supply voltage.
- Potential to develop demand side management incentive for irrigators to curtail irrigation load through peak demand times.
- Twizel and Tekapo tourism development will create winter load peaks

5.3.3.10 GXP New Investment Estimates

The expansion of GXP capacity can either be funded via AEL 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 Transpower Grid Exit Point is shown on a per project basis on the "Tetris" diagram used by Transpower and attached in Appendix H. The actual charges to customers will be subject to the term of investment agreement and the cost of capital payments required by Transpower.

5.3.3.11 Estimated Demand at Zone Substation Level

Table 5.16 shows the aggregated effect of substation demand growth for a 10 year horizon incorporating the anticipated step changes detailed in Table 5.6, applied at zone substation level.

- *Table 5.16: Zone Substation demand growth*

AEL Zone Sub	2013 MW	10 year Rate & nature of growth	2023 MW	Provision for growth
Timaru 11 kV board	61.0 (winter)	0.85% historic some steps expected to come Residential Growth Heat Pump uptake Industry Growth (Washdyke)	76.1 (winter)	Up-sizing Transpower supply point at 11 kV. If a surprise load establishes, transfer some load to a 33 kV supply voltage.
Pleasant Point	3.62 (summer)	4.62% per year expected as TMK Residential load Dairy & Irrigation development	5.69 (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	7.81 (summer)	4.62% per year expected as TMK until SAW then 2 % Residential load Dairy & 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.
Studholme	10.4 (summer)	4.62% per year expected as TMK Residential load Dairy & 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.
Bell's Pond	6.07 (summer)	5.89% per year expected	36.4 (summer)	New sub to offload Studholme and provide more security and capacity. Work needed to carry load which

AEL Zone Sub	2013 MW	10 year Rate & nature of growth	2023 MW	Provision for growth
		Residential load Dairy & Irrigation development		depends on mooted projects progressing.
St. Andrews	Yet to be realised	4.62% per year expected as TMK Residential load Dairy & Irrigation development	29.5 (summer)	New sub to offload Studholme and Pareora and provide more security and capacity
Temuka	50.2 (summer)	4.6% historic on TMK Residential load Dairy & Irrigation development	75.09 (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
Clandeboye 1 & 2	25 (summer)	4.63% historic on TMK Process Expansion & new Dryer	45 (summer)	None required for local assets – 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.
Geraldine	6.52 (summer)	4.63% historic on TMK Residential load Dairy & 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 current demand of 6.5 MW to about 7.8 MW by the end of the planning period.
Rangitata	6.52 (summer)	4.63% historic on TMK Dairy & 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.
Albury 11 kV board	1.81 (winter)	1.51% historic on ABY	1.7 (winter)	Transpower asset under their management. Overall load not expected to breach Transpower's capacity unless Totara Valley

AEL Zone Sub	2013 MW	10 year Rate & nature of growth	2023 MW	Provision for growth
		Residential Load Small subdivision development		Sub built.
Fairlie	2.37 (winter)	1.51% historic on ABY Residential Load Small subdivision development	2.5 (winter)	Regulator upsizing or transformer with OLTC - expect demand to grow from current demand of 2.3 MW to about 3 MW over planning period.
Tekapo	2.6 (winter / shoulder)	4.0% historic on TKA Residential load Subdivision & CBD development Tourism development	6.3 (winter / shoulder)	Substation Transformer will need upgrade towards end of planning period - expect demand to grow from current demand of 2.6 MW to about 4.8 MW over planning period.
Mt Cook & Glentanner	1.3 (winter / shoulder)	4.0% historic on TKA Tourism development	2.1 (winter / shoulder)	Larger capacity transformer bank for Hermitage - expect demand to grow from current demand of 1.3 MW to about 1.8 MW over planning period.
Twizel	2.8 (shoulder)	2.51% historic on TWZ Residential load Large scale Subdivision Dairy & 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	Yet to be realised	Dairy & Irrigation development	2.5 (summer)	New sub to offload Tekapo and provide more security and capacity
Haldon	Yet to be realised	Dairy & Irrigation development	1.3 (summer)	New sub to offload Tekapo and provide more security and capacity

5.3.4 Estimated 11 kV Feeder Demand

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

5.3.5 Estimated Asset Utilisation

In contrast to the general emerging trend of decreasing asset utilisation (i.e. a more “peaky” profile), AEL expects 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 Constraints

5.4.1 Electrical Capacity Constraints

AEL’s network includes the capacity constraints listed at Table 5.14 below.

- *Table 5.17: AEL Network Capacity Constraints*

Constraint	Description	Intended remedy
Waimate Area – Holistic	Lack of capacity for BPD, STA, STU	Work with Transpower on their Lower Waitaki Project to ensure capacity is made available. Three options “socialised” by Transpower and work to be done between 2012 and 2015.
Studholme GXP Supply Security to 110 kV bus	Upgrade N security to N-1	From Feb 2010 110 kV bus is closed during peak NZDL season – Partial fix during high cost part of year. Ultimate, New Investment in Transmission Line – Transpower discussion via Lower Waitaki Project (timing 2012 - 2015)
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 – Transpower discussion underway
Bell’s Pond GXP Supply Security at 110 kV	Upgrade N security to N-1	Bell’s Pond is teed off one cct: WTK-OAM-STU cct 2; as the demand grows install second transformer to be hard teed to the WTK-BPT-OAM cct 1 (timing uncertain).
Bell’s Pond GXP Supply Security via transformer	Upgrade N security to N-1	As the demand grows install second transformer (timing uncertain).

Constraint	Description	Intended remedy
St Andrew's, Waimate	Lack of capacity for Hunter Downs irrigation	Lack of capacity in 11 kV network to supply Hunter Downs irrigation. Build double cct 110 kV line to STU-TIM 110 kV line or double cct 220 kV line to ISL-LIV 220 kV line to make highest security possible supply available.
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.
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. SSR underway. Long term new Investment in Transformers – Transpower discussion for 33 kV solution or hybrid 11 kV and 33 kV.
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).
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 future 11 kV zone substation switchboard,connect and run at 11 kV. Establish Washdyke 33/11 zone substation off 33 kV TIM GXP (timing uncertain).
Timaru Sub-transmission to CBD	Heavy cable loadings	Establish city 33/11 zone substation off 33 kV TIM GXP (timing uncertain).
Pareora 1 & 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 (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	Larger transformer, or second or new substation at Totara Valley for load transfer (timing uncertain)

Constraint	Description	Intended remedy
	vector group changes.	
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.
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.
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 livened in 2012. Complete protection work at Temuka to allow load to be taken.
Rangitata Sub T1	T1 is sized to suit sub-trans.	Upgrading of Rangitata substation underway. New T2 installed at 9/15 MVA. T1 replacement being installed, upgrade from 5/6.25 MVA to 9/15 MVA.
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 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 (2013) ex pre-used Pareora
Otaio Feeder regulation	Voltage constraint at end of feeder	Off load Dairy Factory feeders when second drier established (2015), or if drier delayed put diary on direct supply
Geraldine CBD (GLD) Studholme CBD (STU) Mt Studholme Feeder (STU)	Voltage constraint at end of feeders	Install capacitor 2013/14 plan. Install capacitor 2013/14 plan. Mt Studholme needs chokes on existing site to suit ripple 2013/14 plan.
Studholme Ripple Plant	Ripple signal attenuation will occur with Transpower's new transformers.	Procure new 11 kV cell
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.

There are a number of known load or voltage constraints which may develop on the 11 kV network due to irrigation development. These are often on single 11 kV spur lines that will, over the life of this Plan, require reinforcement to avoid the voltage constraint.

Townships with older residential areas face potential LV constraints as future generations restore bungalows and create new electrical demand in excess of that originally reticulated. Infill housing on vacant sites and site redevelopment by removal of existing house and replacement with multi-units will also incur demand increases. Review of the Temuka and Geraldine areas indicate this potential problem. It also highlights that buoyant economy can drive home appliance investment.

Timaru City is experiencing a greater uptake of heat pumps which will place additional load during winter as well as introduce voltage fluctuations should lower quality units be purchased which do not limit starting inrush current.

The impact of electric motor vehicles is not yet known, this situation will be monitored (refer to discussion in 5.3, above).

The situation is the same for the impact of PV within the planning period.

5.4.2 Non-electrical Constraints

Electricity networks are not only constrained electrically, but are alsoconstrained by the environment within which they are constructed.

5.4.2.1 Coastal environment

Part of AEL's 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 2.6.5).

5.4.2.2 State highways

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 9 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 AEL's backbone network built along the dominant State Highway traffic routes there isis considerable risk of not gaining approval from the road controlling authorities to replace works at end-of-life. While re-poling like for like can occur, often conductor sizes increase with the rebuild requiring new pole positions to cater for changed span lengths. Shifting an overhead asset off the highway if private land owners' approval can be gained, can cause significant additional risk and cost.

5.4.2.3 Available resources

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.

5.4.2.4 Land access agreements and easements

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

5.4.2.5 Resource consents

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

5.5 Use of Distributed Generation

AEL recognises the value of distributed generation in the following ways:

- 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.

However AEL also recognises that distributed generation can have the following undesirable effects:

- Increased fault levels, requiring protection and switchgear upgrades.
- Increased line losses if surplus energy is exported through a network constraint.
- Stranding of assets, or at least of part of an 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.

AEL encourages the development of distributed generation that will benefit both the generator and AEL.

5.5.1 Procedures for Consumers

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.

5.5.2 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.

5.5.3 Connection Terms & Conditions

AEL adheres to the prescribed charges and terms set out in the Electricity Governance (Connection of Distributed Generation) Regulations 2007.

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 AEL.

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

AEL is 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 AEL 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.

5.5.4 Safety Standards

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

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

5.5.5 Technical Standards

Metering capable of recording both imported and exported energy must be installed. If the owner of the distributed generation wishes to share in any benefits accruing to AEL, such metering may need to be half-hourly.

AEL 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 AEL’s own prevailing standards.

5.6 Embedded Generation – Opuha Dam

AEL Energy has had experience operating the Opuha Dam and the associated concepts of distributed generation (DG). 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, hence islanding does not afford much security.

5.7 Non-Network Options

The aim of the company 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.

Extensive use is made of the load management system to reduce network demand, and a number of time or load control options are available to the customer. Network charges are structured to encourage customers to use off peak energy however, this can be made ineffectual by Retail Price packaging.

AEL policy is to facilitate distributed generation.

There is currently one site being monitored for wind speed and direction as a means of reviewing alternative renewable energy opportunities. The site's wind yield appears sub-optimal for commercial development. Unfortunately with the demand for development in this area the price of wind turbines has dramatically escalated which will have an impact on project economics.

Customers 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.

During the transmission constraints into the Zone 3 area over the past two years, AEL has 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.

The high level risk of single transformers at zone substations has been identified in the risk management section of the AMP. The risk treatment supports the use of distributed generation as a method of limited backup supply to mitigate single transformer failure. The cost of purchasing a further spare transformer against the need for managing the planned loss of supply for Twizel and Tekapo substations for 2 – 5 yearly Transpower maintenance is driving further investigation into a portable containerised generator for emergency standby duty or voltage support duty to maintain service standard expectations by our customers. It is also influencing plans for mobile substations (one nationally for Transpower (110/33/11 kV) and one locally for AEL (33/11 kV)) which could double as emergency back-ups (for faults) and as temporary second transformers (for avoiding planned outages that would otherwise be required when maintaining single transformers).

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.

As discussed in section 5.2.1 AEL routinely considers a range of non-asset solutions and indeed AEL has a preference for solutions that avoid or defer new investment.

5.8 Analysis of Network Development Options

At a GXP level AEL is discussing with Transpower the options available to continue to provide the level of capacity and security previously afforded to customers.

The following sections briefly outline the identification, selection and implementation of the most appropriate network development option.

5.8.1 Identifying Options

When faced with increased demand, reliability, security or safety requirements, AEL considers the broad range of options described in Section 5.2.1.

5.8.2 Selecting the Best Option

Once the most appropriate suite of options have been identified using the principles embodied in Figure 5.2, AEL will use a range of analytical approaches to determine which option best meets AEL's investment criteria. As set out in Section 5.2.3, AEL uses increasingly detailed and comprehensive analytical methods for evaluating more expensive options.

5.8.3 Implementing the Selected Option

Having determined that a fixed asset (CapEx) solution best meets AEL's requirements, and that AEL's investment criteria will be met, a project will proceed through the following broad steps:

- 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 cost-benefit analysis if detail costs exceed those used for investment analysis.
- Address resource consent, land owner and any Transpower issues.
- Perform detailed design, including the preparation of drawings, equipment and construction specifications, and tender documents as necessary.

- Tender out construction stage.
- Award tender.
- Close out and de-brief project after construction.

5.9 AEL Network Development Plan

The following two Sections outline a high level development plan for AEL.

AEL has had high load growth with investment applied to the high growth areas such as Bell's Pond, Clandeboye, Temuka and Timaru 11/33 kV step up Substation supply areas.

Other parts of the Network are due for development to improve security and provide the capacity required to meet future loads, especially the Bell's Pond, Studholme/Lower Waitaki Valley areas.

Appendix C at the back of this AMP contains three sets of tables.

Appendix C.1 presents a detailed list of network development projects currently underway or planned to start in the next twelve months (2013-14).

- "L" = Asset Relocations
- "S" = Reliability, Safety & Environment
- "C" = Customer Connection
- "G" = System Growth
- "R" = Asset Replacement & Renewal

Appendix C.2 presents a "summary of development programme" for the four years 2014/15 to 2017/18

Appendix C.3 presents a high level overview of the development plan for the five years 2018/19 to 2022/23.

Appendix C.4 presents the 10 year detailed project phasing, grouped according to AEL asset/job types as follows:

- "A" = Overhead Lines, new & refurbished,
- "B" = Customer Connections, including new subdivisions & extensions for new services,
- "C" = Metering & Relays,
- "D" = Distribution Substations, including transformers, 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,
- "I" = Special – Large System Development Projects,
- "J" = Transpower – NIA (New Investment Agreement),
- "K" = Transpower – GUP (Grid Upgrade Process).

5.9.1 Transpower – Grid Exit Points

AEL has energy supplied via seven Grid Exit Points (GXP). Each GXP is briefly described below.

5.9.1.1 Albury 110/11 kV GXP

Albury is Tee connected to the Tekapo A-Timaru 110 kV line via a couple of 110 kV CBs configured as load break switches. A protection scheme at Timaru will allow faults beyond Albury toward Tekapo A to be cleared via the load break at Albury reducing the outages to Albury by about one half. Transpower has been installing bird perching deterrents about insulators on the TIM-TKA line. Since then this line has been more reliable.

Albury has a single supply transformer bank made up of three single phase units in service with a spare alongside. Should one unit fail a unit change is required to restore supply. These transformers are all aged. They are sized sufficiently just to allow most of the generation of Opuha to pass after the Fairlie and local Albury load is deducted.

If Albury load increases by more than 2 MW, changes to the single supply transformer would need to be made. A load change of this amount could be realised if a Totara Valley Substation were established.

5.9.1.2 Bell's Pond 110 kV GXP

Transpower have provided a hard tee off the STU-OAM-WTK cct 2 to Bell's Pond GXP along with a receiving structure and line disconnector/earth switch. Certain protection, control and measurement equipment has been fitted by Transpower at the zone substation.

As load grows a second arrangement similar to the first will be established to feed a second supply transformer. This is currently being reviewed by Transpower particularly around load constraints on the OAM-WTK cct 1.

A recent suggestion to Transpower is to proceed with one of their ideas to bus 110 kV at Bell's Pond. New load at Cooney's Rd could then be supplied via shunt lines to the existing circuits.

Transpower would only need to reinforce down to Bell's Pond from Waitaki. Shortening the lines would improve security along a similar scenario to that promoted for the Orari 220 kV bus (Geraldine bussing project).

5.9.1.3 Studholme 110/11 kV GXP

Studholme was a lower priority GXP, when the East Coast 110 kV transmission was reduced from twin circuits to single circuit in the 1990's and was left fed from a single tee circuit from Waitaki. A cold change-over is available to Timaru should the Waitaki circuit fail, supply is lost for a number of seconds. In February 2010 a new regime of tying the bus commenced so that the STU 110 kV bus is through-connected from WTK to TIM during the Studholme dairy factory's high loss production period. This regime is now being threatened, Studholme may revert to a single in-feed with cold change-over, a situation that may not be palatable to the connected customers.

This is a short term solution. As South Canterbury and North Otago loads grow, a permanent rearrangement will be required, possibly the reinstallation of the Glenavy-Studholme second circuit so Studholme is fed off two Waitaki circuits.

A review of the whole of the lower Waitaki 110 kV transmission is in progress and a Grid Upgrade Proposal is in negotiation to determine the level of investment in upgrading Transpower's non-core grid assets.

Studholme has a firm transformer capacity of 11 MVA, however the arrangement has the two transformers connected hard in parallel. Each is rated 11 MVA, while both are in service 22 MVA can be taken which meets the present 11 MVA peak demand but without N-1 security beyond 11 MVA

The load will continue to grow at Studholme with increased irrigation load being connected. NZ Dairies have now sold their interest to Fonterra. AEL are to discuss increased loading after Fonterra's work load at Darfield has subsided.

A new GXP at Makikihi/St. Andrews may take 3 to 4 MVA off Studholme, but this investment would require a step change in load, like the Hunter Downs scheme.

Transpower are planning to increase the capacity of the Studholme transformers, but the timing for this is unknown to AEL.

AEL presently owns the Studholme 11 kV switchboard, it has a rating of 23.8 MVA, as the transformers are upgraded Transpower will potentially replace this switchboard.

5.9.1.4 Timaru GXP

Timaru has a central bus of 110 kV which is fed from two 220/110 kV 120 MVA interconnecting transformers and 28 MVA Tekapo A power station. All 110 kV circuits and transformers are selectable to the double bus. Transpower is planning to rationalise the 110 kV bus, but the timing of this is unknown to AEL.

Four lines connect to the 110 kV bus, two to Temuka and one to each of Studholme and Tekapo A.

Three 110/11 kV transformers, configured as three single phase units, connect to the 110 kV bus to supply the Timaru 11 kV GXP. There is one spare unit at Timaru for T2 and T3 and one unit for T4.

The 220/110 kV interconnecting transformers are rated at 120 MVA each and under present peak loading conditions have about 95 MW applied. Transpower consider that if AEL load the transformers to 104 MW while both are in service, this equates to 120 MVA when one is released, due to power factor and loss considerations. 104 MW has become the operational limit with Tekapo A Power Station released.

If AEL uses an 80% factor on its TIM load (summer factor as Timaru winter peaks) and summates with ABY, TKA and TMK at 100% (summer peak loads), the resultant yellow line below indicates the transformer is overloaded.

When the Waimate area loads are connected and Oamaru ignored (the resultant blue line below) the interconnector cannot supply N-1 capacity. Please note that in developing the blue line, it is assumed security will be provided for all the Waimate area loads, except St. Andrews, from Waitaki.

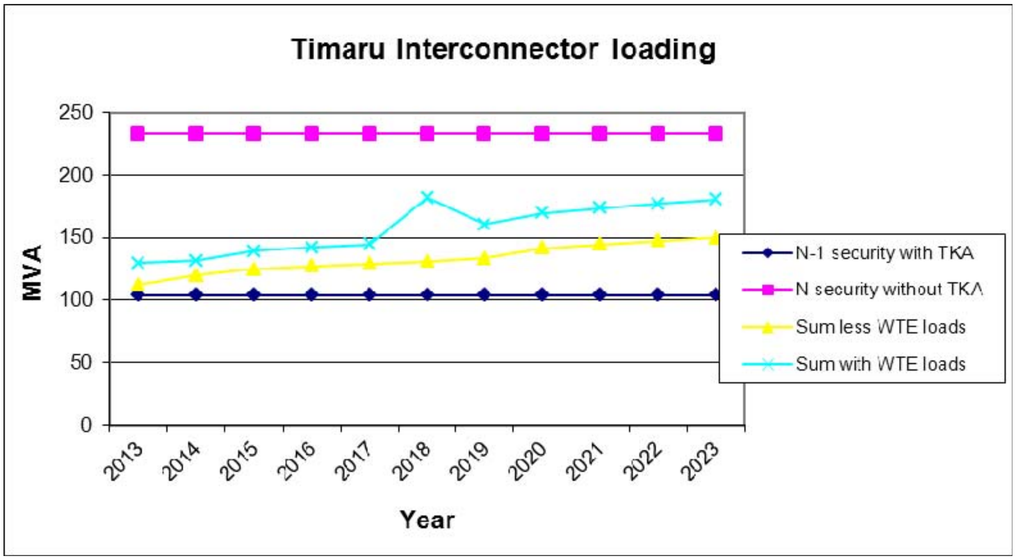


Figure 5.14: Timaru 220/110 kV Interconnecting load

Under one proposal for reinforcing supply to the lower Waitaki Valley area (Studholme included), energy is served from the Timaru 110 kV bus. This will place additional load on the 220/110 kV interconnectors.

Transpower have been encouraged to urgently look at the situation with the interconnectors.

The existing Timaru 11 kV board has been replaced and NERs have been installed to limit the earth fault current produced at the TIM 11 kV GXP.

Two of the three 110/11 kV three single phase unit transformers that supply the 11 kV board are also aged and are unable to supply load at peak demand without significant load control in place with one unit out of service due to the resulting bank capacity constraint. Transpower are looking at a policy of changing out single phase transformer arrangements for three phase unit transformers. 2500 amp (47 MVA) secondary rated transformers with a 20% voltage impedance have been requested by AEL. AEL have also asked for the transformers to run on a two out of three basis with one on hot standby. Transpower are examining this and look to install a higher impedance transformer. This will secure the known load growth until 2022 and not allow the high fault level to become greater.

With the reduction in proposed loads to be applied to the TIM GXP, AEL has decided to postpone the installation of a 33 kV GXP, instead relying on the 11 kV GXP for the foreseeable future. This decision is reliant on the three 110/11 kV transformers being replaced.

5.9.1.5 Tekapo A 11/33 kV GXP

Tekapo A 11 kV board is supplied from the grid via an 110/11 kV transformer. Genesis can make their generator available if the grid is unavailable. Generally when the Tekapo A-Timaru circuit is released, Genesis can run their generation to supply AEL Tekapo load while it is disconnected from the Transpower Grid. This is termed “islanding” the supply to Tekapo.

Tekapo A is also critical for Timaru should the 220 kV supply be lost. The light 15 MVA supply from Waitaki can be augmented with Tekapo A, and 40 MVA of load might be re-established, 47 MVA if Opuha can run stable with Tekapo A.

From the 11 kV bus at Tekapo A there is a step up transformer to 33 kV to supply AEL, there is no alternative supply should this fail or be released.

A study was commissioned to replace the 11 kV board at Tekapo A, by Meridian (previous owners of Tekapo A) and Transpower. AEL would be interested in partnering a change in arrangement of this board. See comment in Tekapo in GXP above and Zone Substation below.

5.9.1.6 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 50.7 MVA (Dec 2011). Since then dry conditions have not been felt, a large number of additional loads would be realised if a dry year was felt.

If there was a loss of one of the 110 kV transformer feeders from Timaru the remaining transformer would be running with spare capacity during peak load periods. Replacement of the transformers has been delayed. Timing is now dependant on Fonterra’s Clandeboye load growth and AEL has nothing firm regarding this.

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.

The Temuka 33 kV bus is configured with four feeders to Fonterra’s Clandeboye plant, which gives Fonterra high security from that bus. Two other feeders connect the local 33/11 kV transformers which supply the 11 kV network. Two additional 33 kV feeders supply Geraldine and Rangitata T2. A second line is being established to feed Rangitata T1 that is teed off one of the four feeders to Clandeboye.

5.9.1.7 Twizel 220/33 kV GXP

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.

Taking a second feeder is not straight forward as the Transpower split 33 kV bus will inhibit either the ability for AEL to run a solid bus should supply be taken from either side of the Transpower bus or end up with a slightly less secure supply if both feeders are connected to the same side of the bus to allow bus tying in the zone substation. Transpower is in agreement that if AEL fit 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 NIC with Transpower.

5.9.1.8 Future Grid Exit Points

AEL is keeping a watch on the Makikihi/St. Andrews areas, the load growth is unprecedented due to dairy and irrigation, a similar GXP to Bell's Pond may be required. Commencement of the Hunter Downs Irrigation scheme would definitely spur the need. This GXP would be constructed by Transpower with subsequent Transmission costs passed through to the customers by way of a new investment agreement.

Transpower had been discussing the option of bussing the 220 kV lines at Orari. The timing is unknown and Transpower is looking at possible non transmission solutions. AEL have expressed an interest in either a 220 or 33 kV GXP. If the GXP is taken at 220 kV a 220/33 kV zone sub would be built at Clandeboye to supply AEL's largest load connected with very high security. If it is taken at 33 kV this would allow Rangitata to be connected more directly. Taking todays 25 MW of load at Clandeboye and 15 MW in the Rangitata area, totalling 40 MW, off Timaru/Temuka would significantly unload assets that nearing full load. Investment could be delayed in the Timaru and Temuka areas.

Toward the end of the planning period there may be a need for a 33 kV GXP at Timaru. This is load growth dependant, should this occur about half of the Timaru 11 kV GXP load would be moved. Transpower are more interested in the transformers being connected to the 220 kV bus to further unload the interconnecting transformers.

Between a new GXP at Orari and a 33 kV GXP at Timaru, reconfiguring the Timaru interconnecting transformers could be delayed beyond this planning period.

5.9.2 AEL - Zone Substation Development

5.9.2.1 Timaru CBD and Residential Areas

The Timaru CBD supply is under review, 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—see the discussion above on the choices for this delay surrounding the Timaru 11 kV switchboard being replaced and the possibility of the 110/11 kV transformers being replaced.

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.

5.9.2.2 Timaru – Grasmere Street

Grasmere St is an AEL switching station comprising an indoor 11 kV switchboard. Four sub transmission cables are received from Timaru and four leave, two each for North St (replaces the Victoria St, decommissioned in 2011) and Hunt St. Ten 11 kV feeders distribute energy to the centre of the city, North Port, Highfield, Maori Hill, and Waimataitai.

The 11 kV board was nearing the end of its economic life. It was replaced in the 2012-13 year. It is housed in a recently earthquake strengthened building and is on a site that suits the purpose of this building and contents. Further strengthening work was undertaken as a part of the 2012/13 work. The site does not allow development for 33/11 kV transformers to be placed. With the supply to the CBD improved with the new North Street substation, the better option is to maintain the supply to Grasmere from Timaru at 11 kV.

5.9.2.3 Timaru – Hunt Street

Hunt St is an AEL switching station comprising an indoor 11 kV switchboard. Four sub transmission cables are received from Timaru, via Grasmere and North St (was Victoria St). Ten 11 kV feeders distribute energy to the centre of the city and to the West End and Watlington residential areas. There are a couple of spare feeder circuit breakers.

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 2013/14 with the SEL 751A.

5.9.2.4 Timaru – North St (was Victoria Street)

North St is a new AEL switching station that replaced the existing Victoria St switching station in 2011 and comprises an indoor 11 kV switchboard. Two 33 kV sub transmission cables run at 11 kV are received directly from Timaru and a further four 11 kV sub transmission cables are received from Timaru via Grasmere and Hunt St. Twelve 11 kV feeders distribute energy to the centre of the city, South Port, Redruth, Parkside, and Kensington.

Under the postponed Timaru CBD project a new 33 kV supply is proposed to be brought to the CBD area, two 33/11 kV transformers installed. The 33 kV cables can be rolled back and connected to the transformer 33 kV switchgear and the incoming circuit breakers connected to the 11 kV terminals of the transformer and 11 kV switchgear. This project is named the North Street Substation and is dependent upon the creation of a 33 kV GXP at Timaru. The proposed North St Substation will be located on the site of, and include, the new North St 11 kV switching station.

In the 2011/12 year two new cables were taken to Timaru’s South Port area and another two to the South to the growing industrial area in Redruth. Over the years various feasibility studies for projects on the wharves have been presented, some require significant energy, AEL is now in a better position to serve these.

5.9.2.5 Pareora

Pareora received a new Reyrolle 11 kV switchboard in 2008 to replace the existing Yorkshire So-Hi board.

Two new 33/11 kV OLTC transformers were commissioned in 2012 to replace the 40 year old existing 5/6.25 MVA units. These new transformers have 9/15 MVA ratings and are connectable in either Dyn11 and Dzn0 configuration, Dyn11 for initial service, and reconfiguration to Dzn0 in the event that a new 33 kV GXP is established at TIM.

Two new indoor GHA 33 kV vacuum switchboards (to replace the existing 50 year old outdoor switch yard) were also commissioned in 2012.

5.9.2.6 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, & 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.

5.9.2.7 PAR-TIM 33 kV Subtransmission 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).

Once these line upgrades are completed, and with the two existing transformers having been replaced by 9/15 MVA units in 2012, and new 33 kV switchgear installed to connect these to the lines, the substations N-1 capacity may be firmed at just over 10 MVA.

In the meantime, the combined load is expected to be 4.5 MVA SFF feeders, 4 MVA rural feeders. plus 1.8 MVA transferred at Otaio from Studholme. The total of 10 MVA being applied to both the Pareora lines is not ideal but should be able to be handled for a short period to allow line re-closure or reconfiguration of loads in the event of one line being lost.

Should the dairy factory at Studholme take connection via dedicated cables from Studholme, their disconnection from the Otaio feeder will allow some of the 1.8 MVA of load to be transferred back to Studholme from Pareora. The amount depends on how much load growth the Otaio feeder has received in the meantime.

In the longer term a new GXP at Makikihi is the optimal solution to allow load transfer.

5.9.2.8 Pleasant Point – Raincliff/Totara Valley/Cave

Load flows indicate that the 33 kV Timaru—Pleasant Point-Timaru line is capable of delivering 8.27 MVA load with a 6% voltage regulation. The line should only be operated to 9 MW.

At present the Zone Substation at Pleasant Point 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 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 voltage sag on the lengthy 11 kV feeder to the Totara Valley area, sag 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 line. 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 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.

5.9.2.9 Temuka

Temuka has AEL's zone substation on Transpower's site - AEL owns the 33/11 kV transformers, 11 kV switchboard and has a 33 kV ripple plant on site fed off a 33 kV bus that allows two selections of supply for the ripple plant.

Four 33 kV feeders to Fonterra are well placed to provide for present needs and some further development at Clandeboye. Little attention is required to these in the short term.

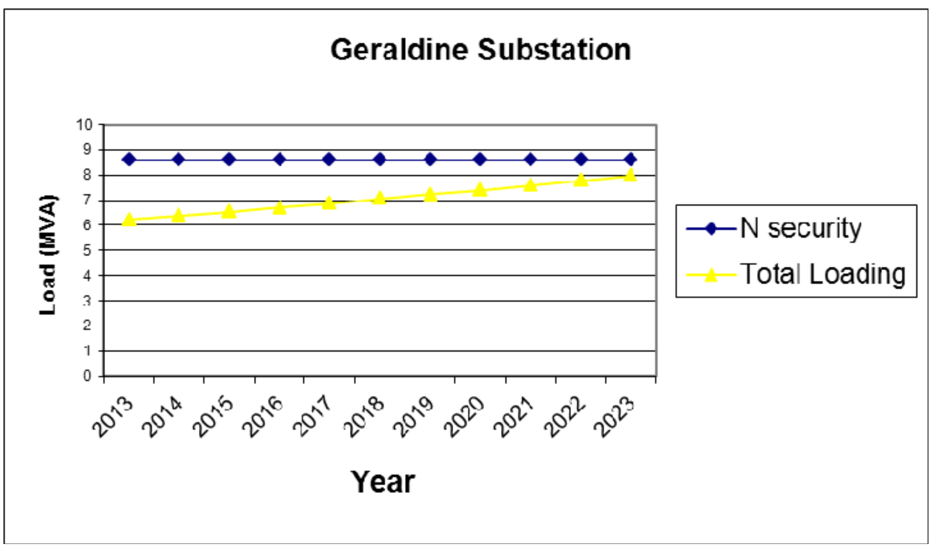
The 19/25 MVA 33/11 kV transformers (2007) and 11 kV bus require little attention.

The HV cell of the ripple plant is currently housed outdoors while the control gear is inside a wooden building along with its 11/0.415 kV local service transformer. A project is underway to rebuild the local service supply to a dual change over set up between two 11 kV feeders.

5.9.2.10 Geraldine

The 33 kV Geraldine-Temuka line is capable of delivering 8.64 MVA with a 6% voltage regulation. The line should only be operated to 8.6 MVA.

Peak loads at Geraldine are nearing 6 MVA. A transformer has been placed at Geraldine with an upper rating of 8.5 MVA to allow some of the Rangitata load to be transferred while the Rangitata substation is being upgraded. This fits within the sub-transmission rating and will serve the load growth for a few years.



▪ *Figure 5.15: Geraldine substation load growth*

A second transformer would ideally be connected to a second 33 kV sub transmission circuit for security, this would need to be constructed. Geraldine substation requires a re-development, the existing substation structure and control room are at end of life. The new substation would include a new N-1 switchroom with 11 kV switchboards and second transformer sited in a new bund. AEL is currently investigating options to purchase more land, either adjacent to the existing substation or for a new site.

Geraldine presently has three feeders, two rural and one to the CBD/Residential area. There has been concern that limited security is available to the Geraldine CBD. Consideration is being given to establishing a fourth feeder so the town load can be split, this feeder could then have a recloser applied at the town boundary so it can pass into the Belfield rural area. The Belfield rural area feeder would help diversify and off load the Rangitata zone substation.

A new 11 kV feeder could be cabled down Downs/Hewlings/Peel onto the river reserve and to join to an RMU by the river crossing. Route length is approximately 1.5 km. Opening switches G229 and applying to G230 would give a reasonable mix of CBD on the existing G191 feeder and the residential on the other side of the river on the new feeder. This development is however some time away and the upgrade to the substation takes precedence.

In order to improve supply security in the meantime, an air break switch will be installed on the outskirts of town to enable the off–loading of the rural supply to Bennetts Road, Woodbury Road, Templer Street and Orari Back Road onto the Woodbury feeder. This will ensure that Geraldine CBD is not switched off for faults on the rural network.

5.9.2.11 Rangitata

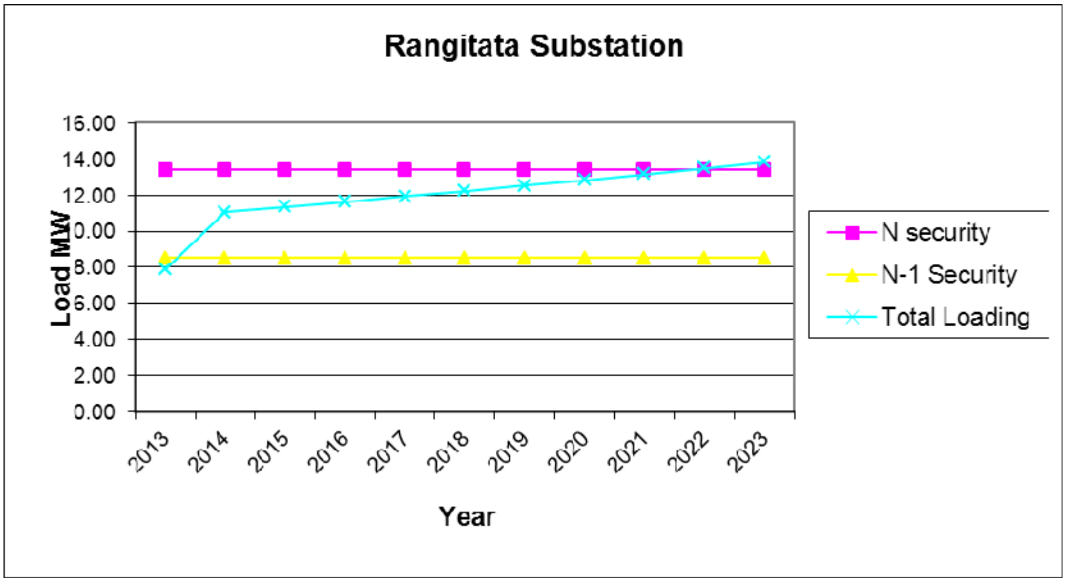
The 33 kV Rangitata-Temuka line is capable of delivering 8.4 MVA with a 6% voltage regulation. The line should only be operated to 8.4 MVA. This now connects to a larger transformer rated 9/15 MVA, so the line limits the loading.

An upgrade of Rangitata consists of the following:

- A second 33 kV circuit from a tee-off at Canal Road off the existing Clandeboye-Temuka 2 feeder with an agreement from Fonterra to take 10 MW normally
- A second 9/15 MVA 33/11 kV transformer to connect to the above line
- Connection of the new transformer to Bus A which couples to Bus B on the original supply, though the buses will be run split. A tie only made if one 33 kV supply fails.

The new feeder although rated higher will be operated at a normal load of 10 MW as per agreement with Fonterra who is the primary consumer supplied by the Clandeboye-Temuka 2 feeder. This gives an N security level of 13.4 MVA while the N-1 security level remains at 8.5 MVA from the old line and under emergency 10 MVA on the new line (as per agreement with Fonterra).

The full capacity of the transformers would be realised if a new GXP is established at Orari or Clandeboye as discussed above.



- *Figure 5.16: Rangitata substation load growth*

Up to 3 or 4 MW of load is expected to be applied with the commissioning of the Rangitata South Bank Irrigation scheme from summer 2012, initially 1 MW, and then in 2013, 3 MW. (Loads to be redefined to match project progress).

Reconfiguration of 11 kV feeders at the station was done during the dairy off season in 2012, two added to give better security toward the East and West.

A 5/6.25/8.5 MVA transformer was removed; it may be relocated to Pleasant Point substation after thorough maintenance to upgrade its conservator tank, fix oil leaks, and etc. More studies are required in this area.

5.9.2.12 Clandeboye

The 33 kV Clandeboye-Temuka cable 1 is capable of delivering 21.3 MVA with a 20% cable de-rating. The cable should only be operated to 21.3 MVA.

The 33 kV Clandeboye-Temuka line 2 and line 3 is capable of delivering 23.4 MVA with a 50 °C conductor limit. The lines should only be operated to 23.4 MVA.

The 33 kV Clandeboye-Temuka cable 4 is capable of delivering 24.2 MVA with a 20% cable derating. The cable should only be operated to 24.2 MVA.

Clandeboye has been well invested in, there is little work planned for the 10 year period of this plan. The zone substations have capacity to meet on–going needs.

Incremental additions to the reticulation will be required from time to time to suit Fonterra's project work.

Fonterra have delayed the addition of a fourth drier with their present work at Darfield. Previously a spare 11 kV circuit breaker had been left for the supply to a new load like this. Two new CB's will be required from Sub 2.

A review of security to the sites should be carried out when this is revisited.

5.9.2.13 Studholme

Studholme is an AEL switching station on Transpower's site - AEL owns the 11 kV switchboard and has a ripple plant on site. As Transpower increase the size of the 110/11 kV transformers and the load exceeds the rating of the 11 kV switchboard (23.8 MVA), a suitably rated 11 kV switchboard will need to be installed.

If Bell's Pond gains a second supply transformer, the reliance on Studholme to provide emergency supply to the Bell's Pond area will cease. The existing switchboard should then carry through until a major project, like Hunter Downs or major expansion at NZDL (Fonterra Studholme), requires its upgrade.

If AEL's switchboard is removed from Studholme due to becoming undersized, it could be moved to another zone substation, possibilities are Geraldine or Twizel. This is dependent on the requirements at these places and the timing.

5.9.2.14 NZ Dairies - Fonterra Studholme

Prior to NZDL's receivership, AEL had asked NZDL to direct connect their two feeders to the back of two existing CBs. The supply still needs improvement to relieve the NZDL temporary overhead connection from causing voltage sag in the feeders, Otaio particularly. Further 11 kV circuit breakers and underground feeders may be required with any expansion of the NZDL complex.

The present infrastructure includes a boiler set sufficient to run two medium sized driers, only one drier is presently installed.

Discussions are expected with Fonterra after their effort applied to Darfield subsides.

5.9.2.15 Bell's Pond

Bell's Pond was an AEL initiative to build an AEL owned 110/33/11 kV zone substation off the STU-OAM-WTK 2 110 kV transmission circuit. A hard tee and 110 kV line isolator is provided by Transpower as a GXP with the associated protection, control, and metering at Bell's Pond.

This saved building sub-transmission circuits from Studholme to the lower Waitaki Valley which would have been very problematic for various reasons as mentioned in the previous AMP.

A 20/15/15 MVA (winding related) 110/33/11 kV transformer was installed, connecting to three 11 kV feeders at Bell's Pond. This was commissioned in September 2010. The third 15 MVA winding is for a future 33 kV bus. This will allow expansion should the Waihoa Downs/Elephant Hills irrigation (part of ISCI), a tunnelling machine or similar loads be established.

The initial load at the end of 2010 of 6.23 MVA (estimated at between 6 to 8 MVA in a dry year), is beyond the 5 MVA critical criteria for a second transformer, however space has been left for the installation of a second transformer at a later stage.

If load predictions for the 33 and 11 kV buses are larger than first identified, then there is a possibility that the BPD transformer T2 may be too small and could be reused on an alternative site.

5.9.2.16 Makikihi/St. Andrews

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.

AEL is relaxed either way. The latter would suit the tunnel project better and further dissect one of the less reliable 220 kV circuits. Ideally the Orari (Geraldine) bussing project would be built first to save possible volt drop from a long feed from Islington (repeat of Timaru's issue when first supplied off the same circuit).

It is proposed to install a 40 MVA 110/11 kV or 220/11 kV (33 kV will be considered) transformers, connecting to pumps and at least three feeders in the vicinity of Otaio/St. Andrews. As the project evolves more certainty over sizing etc. can be given.

This project will be essential should the Hunter Downs Irrigation scheme (part of ISCI) proceed.

5.9.2.17 Albury

Albury is an AEL zone substation on Transpower's site - AEL owns an 11/33 kV 7 MVA step up transformer with alternative 11 kV feeder connections that permits the Transpower 11 kV GXP switchboard to supply the AEL 33 kV line to Fairlie and Opuha. AEL also has an 11 kV ripple plant on site.

Transpower has carried out a project in 2011 to replace their 11 kV switchboard, and AEL has taken the opportunity to replace the original 11 kV feeder cables.

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.

5.9.2.18 Fairlie

Fairlie is seeing steady increases in load with dairy conversions, irrigation, and increased holiday maker activities. The 2 MVA regulator is becoming a constraint with up to 2.3 MVA of load passing through it. The 3 MVA transformer will soon be too small as well. The installation of a transformer ex-Pareora (5/6.25 MVA) would give the site suitable capacity.

The arrangement of the Fairlie 11 kV feeders is due for review as faults in the Fairlie township lead to a total loss of all three feeders. The transformer upgrade may provide the opportunity for a general substation upgrade. Further study is required.

5.9.2.19 Tekapo

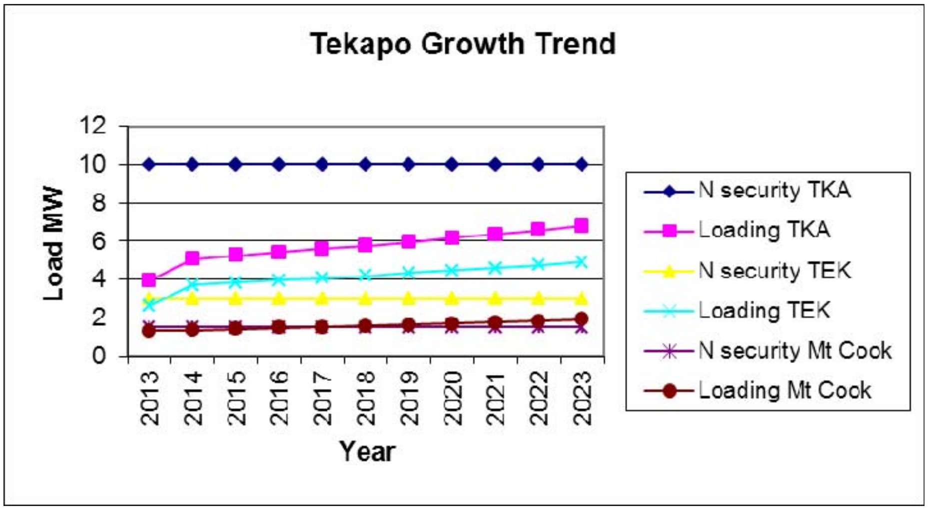
Tekapo has a 3 MVA OCTC transformer with about 2.6 MVA of load applied. The load had been experiencing significant growth before the present recession started in 2009. Due to Tekapo's popularity during holiday periods and during the snow season the load has plateaued. New accommodation had been built and a commercial centre proposal was in the RMA process.

AEL's Zone substation has indoor 11 kV switchgear. The 11 kV switchgear supplies two feeders into Tekapo township as well as 11 kV feeders into Haldon/Lilybank and Balmoral/Simons Pass which utilise 22 kV auto transformers to supply long lengths of 22 kV lines connecting sparsely populated areas.

The Tekapo CBD load had been growing due to subdivision and tourist accommodation development. The Cairns subdivision, up to 1000 sections for various uses over a 40 year term, is just starting to get under way with the initial stages being marketed. This could add a few MVA to Tekapo's load over the term of the subdivision.

The new Peppers Bluewaters resort is now operational with three 200 kVA transformers installed. The new Hot Pools/Ice Rink is fully operational with a 500 kVA transformer installed.

The proposal to develop the Tekapo CBD is on hold, if it had occurred at least 1 MVA of load would have been realised. The step load in the graph below allows for this development in 2014.



▪ ***Figure 5.17: Tekapo Load growth***

A supply to the Mt Cook area is made from Tekapo with a load of about 1.3 MVA. Mt Cook village has also seen growth in recent times to meet the tourism demand.

Transpower and Genesis have started discussion again on the relocation of the 11 kV switchboard. This will provide an opportunity for AEL to make changes to its supply.

At present the supply is via a Transpower 11 to 33 kV step up transformer, benefit was seen in requesting the decommissioning of the 33 kV POS, taking its 11 kV feeder and requesting a second 11 kV feeder to allow two direct 11 kV cables (say 8 MVA each) to be laid to the Tekapo Village Sub. From there a step up transformer to 33 kV would be arranged (the existing transformer turned around) to feed the Mt Cook area.

The above also gives an opportunity for an 11 kV bus coupler to be installed between the AEL feeders at TKA, with the Transpower 110/11 kV incomer aligned to one side of the 11 kV bus and the Genesis Energy generator to the other. This arrangement allows two forms of supply to be made available with separation of supplies if required.

The above arrangement would offset the need to increase the size of the Tekapo Village step down 33 to 11 kV transformer, and provide Tekapo Village with a lot more security.

If it were decided to retain the existing switchroom and clean it up a bit to allow the installation of additional breakers, this would not allow the configuration as described above and hence there would be no reason for AEL to participate in this project.

If the rearrangement of the 11 kV board does not occur and the present supply arrangement is retained, AEL will look to replace the 33/11 kV transformer in the Village Sub to meet the growing load of the Village. The installation of a transformer ex-Pareora (5/6.25 MVA) would give the site suitable capacity.

5.9.2.20 Haldon-Lilybank

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 economic 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.

An enquiry has been made for a power supply to the Black Forest Motor Camp to allow sewage treatment etc. There is insufficient capacity and a 5 km line extension would have been required.

5.9.2.21 Balmoral

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.

This substation will now be disestablished in 2013/14, the 22 kV line operated at 11 kV, and the several existing 22 kV distribution transformers replaced with standard 11 kV distribution transformers.

5.9.2.22 Unwin Hut

Unwin Hut has a 1.5 MVA OLTC transformer with an estimated 1.1 MVA of load applied. There are two independent incoming 11 kV South Wales CBs that feed a ring around the Mt Cook village.

The load in the Mt Cook area is slowly growing due to tourism growth.

The transformer was repainted and OLTC refurbished in 2008. It is suitable to operate until the end of the 10 year planning period provided the load does not exceed rating. The remaining substation equipment should be reviewed to confirm it is suitable to operate until the end of the planning period.

5.9.2.23 Glentanner

Glentanner has about 0.3 MVA load being supplied via a 0.6 MVA OCTC transformer. As load grows at Unwin Hut more line and transformer regulation will occur, giving Glentanner wider supply voltage variations.

Two options have been explored:

1) If the 1.5 MVA transformer becomes spare from Unwin Hut it should be transferred to Glentanner as it has an OLTC. Power quality improvements will be made for Glentanner. Alternatively a regulator could be installed.

2) Put all the load after Glentanner back onto 33 kV thus disestablishing the zone substation. The voltage regulation studies show suitability for this arrangement with the voltage regulation of the 33/11 kV step down transformer removed. This area was originally 33 kV, most of the construction remains, the job is relatively straightforward.

5.9.2.24 Twizel

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. The 11 kV BTH switchgear (with Metro Vickers protection relays) is of unknown age, listed as 1971 in AEL's records being the hand over date from the MoW, but more is likely 1951 vintage as per CB nameplate. The Zone Substation was built to service the Waitaki hydro project largely with second hand materials and was due for removal at the end of the project (circa 1985). With Twizel being retained as a successful township the substation has been in service beyond its design date. It is due for refurbishment.

AEL is seeking information from the main developer to firm their plans as they have indicated possibilities for larger scale subdivisions. Other smaller subdivision developments are presently in progress.

Other proposals of irrigation have been presented for the area, none on the Twizel side of the Waitaki River have proceeded, some to the South in Network Waitaki's area have.

If they proceed, a mix of 11 kV and 33 kV supply options are available:

- Possible Pukaki Outlet 33/11 kV Zone Substation (estimated for 2015/16)
- Possible supply past Ohau C power station to Haldon

At present there is low security to the Twizel Village Substation and the substation is aged. Options over location and type of rebuild are being explored.

Discussions with Transpower have been held to gain an additional 33 kV feeder, see the section on the Twizel GXP above.

The future location of the zone substation, be it on the existing site or on a new site, is being reviewed.

5.9.3 Voltage Support

5.9.3.1 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.

5.9.3.2 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. AEL has standardised on 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.

5.9.4 Line Reclosers

The AEL Network has a number of reclosers that are at the end of their economic life. These include a number of “Ball and Chain” type reclosers that are due for replacement.

However, the 2011/12 year focused on upgrades of firmware for existing NOJA reclosers that had recently exhibited operating issues. Some replacement of obsolete reclosers was continued but a hold was placed on installing new sites due to some technical issues. Once these issues have been resolved, AEL intends recommencing the 5 per year change out of older reclosers and the installation of new sites as required.

Inclusion of more 11 kV line reclosers at new sites 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.

The new and replacement programmes were again delayed in 2012/13 for the technical reason discussed above. For the replacement programme the supplier has advised upgrading of the firmware of the recently installed reclosers. For the new sites, the problem is still under study.

The bulk of the budget for new installations in the 2012/13 planning year was spent on sites preparing for recloser installation. The budget for 2013/14 again allows for three units to be purchased for further change outs.

5.9.5 Sub-Transmission Overhead Lines

Allowing energy delivery to zone substation LV bus bars is basically limited by the transformer rating (as discussed above) and/or the sub transmission circuit capacity as shown below.

Where substation limits are created by sub-transmission circuit constraints, solutions need to be found in providing an additional circuit, an additional zone substation or providing reactive support (capacitors) to allow line loss and load loss compensation. Table 5.18 below lists the power flow limits for existing circuits.

- *Table 5.18: Power flow limits of existing circuits*

Line	Make up	Limit at 6% volt drop (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable (MVA)	Lowest Limit (MVA)	Notes
ABY-FLE	Dog	7.12	12.6		7.12	
FLE-OPU	Jaguar/Cable 1/300	7.65	23.4	21.3	7.65	
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	
GLD-TMK	Cable 1/400 /Dog	8.64	12.6	24.2	8.64	
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	Cable 2x1/300/ Jaguar	21.26 (14.95 towards RGA2)	23.4	32	10	10 MVA take agreed with Fonterra
PAR-TIM 1	Mink/Petrel/Rango Cable 1/95/ 37/0.016	6.81	10.3 11.4	11.5	6.81	
PAR-TIM 1	Iodine/Petrel Cable 1/95	10.77	16.6 11.4	11.5	10.77	Rebuild underway
PAR-TIM 2	Quail/ Cable 1/95/ 19/0.014	6.91	10.3	11.5	6.91	
PAR-TIM 2	Iodine/	10.09	16.6	11.5	10.09	Rebuild

Line	Make up	Limit at 6% volt drop (MVA)	Limit of Conductor at 50 °C (MVA)	Limit of Cable (MVA)	Lowest Limit (MVA)	Notes
	Cable 1/95					underway
PLP-TIM	Quail/Dog/Weke/ 19/0.014 Cable 1/95	8.27	10.3 12.6 16.6	11.5	8.27	
TKA-TEK	Dog	82.48	12.6		12.6	
TEK-Mt Cook Stn	Dog/Flounder	2.25	12.6 8.6		2.25	
Mt Cook Stn -UHT	Mink/Petrel	1.2	10.3/ 11.4		1.2	
Mt Cook Stn -GTN	Mink	6.84	10.3		1.55	

The limits calculated above are based on the conductor rating information as taken from the General Cables web page on 7/1/2010 are listed below.

- Jaguar ACSR 410 A at 50 Deg C Summer Noon or 23.4 MVA at 33 kV
- Cu 19/0.014 320 A at 50 Deg C Summer Noon or 18.3 MVA at 33 kV
- Weke AAC 290 A at 50 Deg C Summer Noon or 16.6 MVA at 33 kV
- Iodine AAAC 290 A at 50 Deg C Summer Noon or 16.6 MVA at 33 kV
- Dog ACSR 220 A at 50 Deg C Summer Noon or 12.6 MVA at 33 kV
- Petrel HSC 199 A at 50 Deg C Summer Noon or 11.4 MVA at 33 kV
- Mink/Quail ACSR 180 A at 50 Deg C Summer Noon or 10.3 MVA at 33 kV
- Flounder ALPAC 100 A at 50 Deg C Summer Noon or 5.7 MVA at 33 kV
- Flounder ALPAC 150 A at 75 Deg C Summer Noon or 8.6 MVA at 33 kV

- 1/95 Al XLPE 252 A direct buried vis 202 A at 80% rating or 11.5 MVA at 33 kV
- 3/95 Al XLPE 250 A direct buried vis 200 A at 80% rating or 11.5 MVA at 33 kV
- 3/150 Al XLPE 321 A direct buried vis 256 A at 80% rating or 14.7 MVA at 33 kV
- 1/150 Al XLPE 318 A direct buried vis 254 A at 80% rating or 14.5 MVA at 33 kV
- 1/300 Al XLPE 467 A direct buried vis 373 A at 80% rating or 21.3 MVA at 33 kV
- 1/400 Al XLPE 530 A direct buried vis 424 A at 80% rating or 24.2 MVA at 33 kV
- 2x1/300 Al XLPE 934 A direct buried vis 560 A at 60% rating or 32 MVA at 33 kV

The Flounder 75 degrees C rating has been used above.

Cable de-rating factors have nominally been applied at 20%, except TMK-CD 2&3 where 40% is applied due to their duplex lay. The ground conditions, proximity of other cables, etc. has not been examined.

5.9.5.1 Rangitata - Temuka

As discussed in 5.9.2.11 above, a circuit off the Temuka Clandeboye 33 kV line was built in 2011 to take up some spare capacity on this circuit.

Management is needed between the two lines to Rangitata to maintain the load on Rangitata substation.

5.9.5.2 Geraldine - Temuka

Geraldine has sufficient capacity in its sub-transmission circuit for the foreseeable future; the limitation is the security. Geraldine is on a single circuit, a second circuit will allow greater security.

5.9.5.3 Pareora – Timaru 1

As discussed above, the load at Pareora post event can cause the circuit to over load.

The 33 kV lines are currently being upgraded over a four year period. Completion is planned for 2017.

5.9.5.4 Pareora – Timaru 2

As discussed above, the load at Pareora post event can cause the circuit to over load.

The 33 kV lines are currently being upgraded over a four year period. Completion is planned for 2017.

5.9.5.5 Pleasant Point

Pleasant Point has sufficient capacity in its sub-transmission circuit for the foreseeable future, the limitation is the reliability. Pleasant Point is on a single circuit. A second circuit will allow greater security.

An option is to build a new sub-transmission circuit to Totara Valley (if this zone substation site is chosen over Raincliff).

Alternatively a second 33 kV circuit could be built to Pleasant Point, then a sub transmission circuit built out to Totara Valley from Pleasant Point but the length would lead to voltage sag issues.

An option exists with a future Washdyke zone substation to create a 33 kV bus there, then reorganise the sub-transmission from the new site.

5.9.5.6 Raincliff/Totara Valley

If a new Zone Substation is built in Raincliff/Totara Valley area it could be supplied from a Tee off from the ABY-FLE line at the Cricklewood 33 kV ABS. The route would be down Rockwood Rd-Mt Gay Rd/Hazelburn Rd. Detail to be determined.

Feeding this site from Timaru could lead to voltage sag issues due to the long length.

5.9.5.7 Bell's Pond

With the new Substation build, a 15 MVA 33 kV winding was included in the transformer. This will allow 33 kV to be taken from the site when need arises. Two feeder locations were allowed for in the design.

5.9.6 Distribution Overhead Lines

General work will be required from time to time to increase conductor size where regulators and capacitors can no longer provide sufficient support. This will be identified from year to year and included in the annual work programme.

New lines will be built from time to time to suit new customer demands.

5.9.7 Sub-Transmission Cables

1200 mm^2 33 kV sub transmission cables have been run from the proposed Timaru 33 kV GXP to North Street and are energised at 11 kV from the TIM 11 kV GXP. These are run as 3 x single cores in trefoil arrangements.

1200 mm^2 33 kV sub transmission cables are proposed to be run from the proposed Timaru 33 kV GXP to Seadown (Washdyke). .These also will be run as 3 x single cores in trefoil arrangements. The 33 kV cables have ratings in the order of (with 80% derating):

- Seadown 1200 mm^2 50 MVA @ 33 kV or 18 MVA @ 11 kV
- North St 1200 mm^2 50 MVA @ 33 kV or 18 MVA @ 11 kV

Although 800 mm^2 cables is the technology limit in NZ manufacture, 1200 mm^2 cables have been adopted as they can be transitioned to 630 mm^2 Cu for connection to switchgear.

The Timaru to Seadown cables are planned to be laid in 2014/15, and commissioned then at 11 kV.

5.9.8 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.

5.9.9 Protection, Control and Measurement

5.9.9.1 Protection

AEL has a mix of protection equipment installed. Recent substations have had microprocessor equipment like SEL, MiCom and Reyrolle Argus installed. This has a nominal life of 20 years. The oldest (Reyrolle Argus) is 1997 era so is due for replacement in this planning period (2017). However some have been brought forward as they are connected to modern substation controllers to update their IED interface.

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 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 then the protection is replaced.

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 & 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.

Are flash detection (AFD) equipment has been installed on recent switchgear at 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.

AEL has three substations with fast bus blocking schemes, PLP, STU and TMK.

5.9.9.2 Control

With the introduction of Central 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 comms outages.

PLP and GLD are 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.

5.9.9.3 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.

5.9.10 Communications

AEL has a mix of:

- Tait VHF and two bit alarm systems
- Tait 300 UHF radio connecting Conitel protocol RTUs 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 & Micom relays

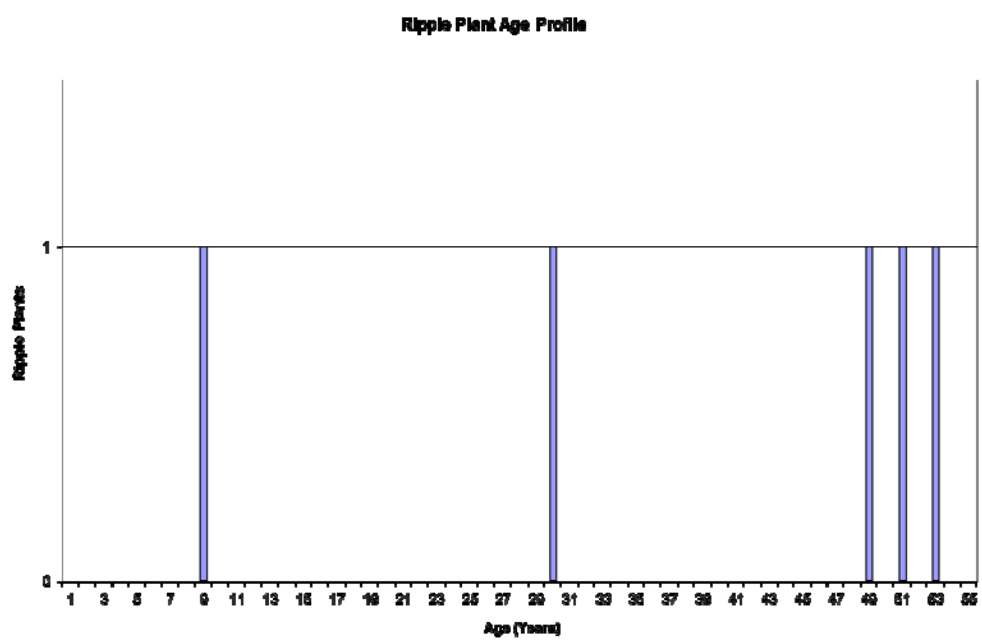
AEL is working toward retiring the Tait VHF and 300 UHF analogue radio networks for Network Control. Fibre and digital radio are the preferred replacement options.

5.9.11 –Ripple Plant

The age profile of the current ripple injection plants is shown in Figure 5.17 below.

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 as per the programme outlined in the table below:



▪ ***Figure 5.17: Ripple Plant Age Profile***

The replacement of ripple receive relays will be coordinated with the updated replacement programme, which is shown below.

▪ ***Table 5.21: Ripple Plant Replacement Programme***

Item:	Year:	Programme:
1	2010/11	Reviewed rotating plant condition in Albury & Tekapo areas *(completed)*
2	2010/11	Reviewed local service security to Albury ripple plant converter *(completed)*
3	2012/13	Reviewed local service security to Temuka ripple plant converter *(reviewed, but design to be studied)*
4	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)*
5	2013/2014	Build and Commission new plant at Tekapo, subject to Item 1 (about 800 relays to change)
6	2013/2014	Build and Commission new plant at Albury, subject to Item 1 (about 1600 relays to change)*(installation date revised)*
7	2014/2015	Decommission rotating plant at Tekapo, subject to Item 5 which replaces with modern electronic plant *(date revised).*
8	2013/2014	Decommission rotating plant at Albury, subject to Item 6 which replaces with modern electronic plant *(date revised).*
9	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).*
10	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).*
17	2013/14	A second review of the proposed Timaru replacement plant of Item 9, above, is required in light of technical issues *(to be reviewed in 2013/14).*

To date AEL has standardised on 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" AEL 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.

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

The Temuka ripple plant does not have an automatic selection on its local service supply, after a cable fault (April 2009) the ripple plant was left without local service during a routine injection, this lead to the catastrophic failure of the converter. Modern design would not include for the local service transformer and oil filled RMU to be housed in the same room as the converter and SCADA/radio equipment, a study will be carried out to determine if the local supply for the ripple plant can be improved.

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.

5.10 Large Projects

This section describes and details the justification for AEL's CAPEX Worksplan as listed in Appendix C1. New and Upgraded Overhead Lines Projects are listed as a single category on the Worksplan in Appendix C4. The justification for the individual projects as listed in Appendix C1, with budgets exceeding $500,000 is detailed below:

5.10.1 Project Name: BPD - Cooneys Road 33 kV

Estimated Cost: $3.5 million

This project comprises the building of a 110 kV double circuit from Bells Pond substation to Cooneys Road. The supply is for the proposed Oceania Dairy Factory to be constructed along Cooneys Road. The double circuit will be operated at 33 kV initially until the load exceeds 10 MW when it will be supplied at 110 kV.

Justification:

Alpine Energy was approached by Oceania Dairies to build a power supply to the proposed dairy factory site. The project is undertaken as a chargeable project.

Alternative Options:

The existing 11 kV passing along Cooneys Road is not sufficient to supply the power required by the dairy plant. Alternative supplies options evaluated were from Studholme substation but this is further from the site than Bells Pond. A 33 kV solution was also investigated but once the load at the dairy factory exceeds 10 MW, 33 kV would be insufficient to supply the increased load.

5.10.2 Project Name: BPD – 33 kV CB for Oceania Dairies

Estimated Cost: $700,000

This project aligns with the project described in paragraph 5.10.1 above and establishes a 33 kV circuit breaker and bay with associated protection at Bells Pond substation supplying the overhead circuit to the Oceania Dairy factory on Cooneys road.

Justification:

As detailed in paragraph 5.10.1 above.

Alternative Options:

As detailed in paragraph 5.10.1 above.

5.10.3 Project Name: Cooneys Road Oceania Dairies Substation

Estimated Cost: $2,350,000

This project comprises the building of a zone substation on Cooneys road supplying the proposed Oceania Dairies factory. The substation will initially accommodate a 33 kV circuit breaker, two 11 kV incomer circuit breakers, with one 9/15 MVA, 33/11 kV transformer supplying an indoor 11 kV busbar with four feeder circuit breakers and two bus couplers. The structural works and layout will be constructed to accommodate 110 kV equipment and associated clearances.

Justification:

As detailed in paragraph 5.10.1 above.

Alternative Options:

As detailed in paragraph 5.10.1 above.

5.10.4 Project Name: Wilson Street Undergrounding

Estimated Cost: $807,000

This project budget is for the completion of the undergrounding of Wilson Street. After the Christchurch earth quake, undergrounding was put on hold until a clearer understanding was gained of the implications on Alpine's network taking into account local soil types and ground conditions.

Justification:

Wilson Street is a the second to SH1 (Evans St, Theodosia St, Craigie Ave, King St) the major North-South route through Timaru and the council has upgraded this street to accommodate higher traffic volumes. In this regard Alpine agreed some time ago to underground Wilson Street.

Alternative Options:

Retain overhead infrastructure. This would however have increased supply risk along a busy route.

5.10.5 Project Name: Guinness Street undergrounding

Estimated Cost: $538,000

This project comprises the undergrounding of 390 meters of 11 kV and 400 V overhead lines along Guinness street in Timaru.

Justification:

The existing 11 kV overhead conductor is light and borderline with respect to fault rating. The Timaru district council's district plan dictates that any upgrading to existing overhead infrastructure must be under grounded.

Alternative Options:

The high three phase fault levels are as a result of the Transpower transformer impedances at Timaru substation along with the configuration of the network. The planned upgrade of the supply transformers at Timaru substation by Transpower will increase the three phase fault level, hence doing nothing is not an option.

Alpine have engaged with Transpower to manage the replacement transformer impedances to effect the smallest increase in fault levels practically possible. Adding reactors in series with the transformers will reduce the fault levels but the cost would be more than the undergrounding of infrastructure along Guinness street.

5.10.6 Project Name: Pareora Sub transmission lines reconductor

Estimated Cost: $822,000

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 will spans four years

Justification:

These two feeders supply the Pareora substation. The major load connected to this substation is SSF which is AEL's 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 AEL's 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.

Alternative Options:

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

5.10.7 Project Name: New subdivisions & extensions
Estimated Cost: $1.5 million

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

Justification:

Electricity demand growth and new connection applications.

Alternative Options:

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.

5.10.8 Project Name: New Distribution Transformers
Estimated Cost: $600,000

This budget item goes hand in hand with new connections and extensions. It also caters for replacement transformers as a result of faults or capacity constraint replacements.

Justification:

Electricity demand growth and new connection applications as well as replacement of faulty transformers.

Alternative Options:

N/A

5.10.9 Project Name: Network – Diesel Generators
Estimated Cost: $980,000

This budget is to purchase two 650 kVA diesel generators to be built onto two trailers and operated through a step-up transformer and associated switchgear and protection for connection to the 11 kV network.

Justification:

SAIDI and SAIFI targets are getting more and more stringent and distribution companies are required to improve quality and reliability of supply. In order to improve reliability and manage

SAIDI and SAIFI targets better, these generators will assist in the first instance with maintaining supply during planned network outages. Secondly, where network emergencies results in prolonged outages, these generators can be deployed to restore supply to parts of the affected network while repairs are being done.

Having two generators with a total capacity of 1 MW gives Alpine more options in terms of it application. This rating would allow the support of multiple distribution transformers at the same time.

Alternative Options:

Doing nothing is not an option. Automation of the network is progressing but this will only contribute to reducing SAIDI and SAFI minutes through expedient network restoration. Reducing SAIDI and SAIFI minutes during planned outages can only be achieved through network ties and/or alternative generation.

6.

Life Cycle Asset Management Planning

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

6.1 Maintenance Planning

AEL manages existing assets on a number of objectives set down from the corporate intent of the business of providing a safe, efficient, reliable and cost effective energy delivery system.

Decisions for example on the type of distribution transformers 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. Alpine’s 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 maintenance, and the frequency of maintenance. However, switchgear and protection devices require regular routine inspection, testing and maintenance to ensure that deterioration or failure of components do not go unnoticed and untreated. Failure of these types of devices may lead to unsafe conditions for the Network.

Not with-standing 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 staff and system control staff that during daily events (planned or fault restoration) operate the assets to maintain safety, security and supply reliability.

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.

Summarising the above discussion, the main planning criteria and assumptions for life cycle management of the network assets are (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 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.

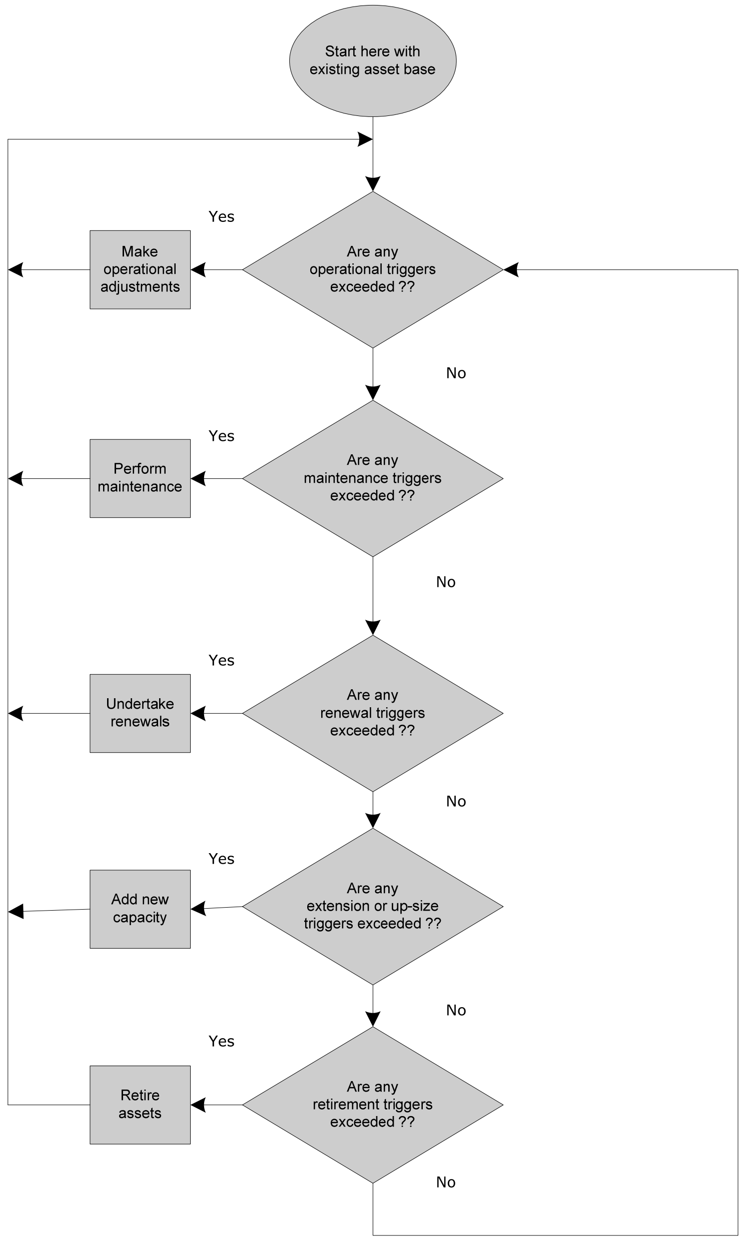
The following table illustrates the linkages between these objectives of the corporate intent and the planning criteria and assumptions (listed in approximate order of priority).

- ***Table 6.1: Relationships between the maintenance planning criteria and the objectives of corporate intent:***

Criteria:	Safety:	Efficiency:	Reliability:	Economy:
Safety of public & employees	X			
Statutory & 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 & size	X	X	X	X
Loading & 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

6.2 Understanding Asset Lifecycles

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



- ***Figure 6.1 Asset Lifecycle***

Table 6.2 below provides some definitions for key lifecycle activities:

▪ *Table 6.2 – Definition of key lifecycle activities*

Activity	Detailed definition
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. Tree cutting is included in operational.
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.
Renewal & 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 (i.e. restricted to Quadrants 1 and 2 in Figure 5.1).
Extensions	Involves building a new asset where none previously existed because a location trigger in Table 5.2 has been exceeded e.g. 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. Not with-standing any surplus capacity in upstream assets, extensions will ultimately require up-sizing of upstream assets.
Retirement	Generally involves removing an asset from service and disposing of it. Typical guidelines for retirement will be when an asset is no longer required, creates an unacceptable risk exposure or when its costs exceed its revenue.

6.2.1 Operating the Assets

As outlined in Table 6.2 operations predominantly involves making no physical changes to the Network other than its switching configuration (connectivity) and simply letting the electricity flow from the GXPs to consumers' premises year after year with occasional intervention 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 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 relays.	Reactive
		Open & 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 rating	Open & 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 & close CBs, reclosers and ABS's to shift load	Proactive or reactive
	Fault has occurred	Open & 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	Shift load to other transformers by moving LV link box open points	Reactive
LV distribution	Voltage is too low at consumers' board.	Supply from another transformer or LV circuit, if possible, by moving LV link box open points.	Reactive

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

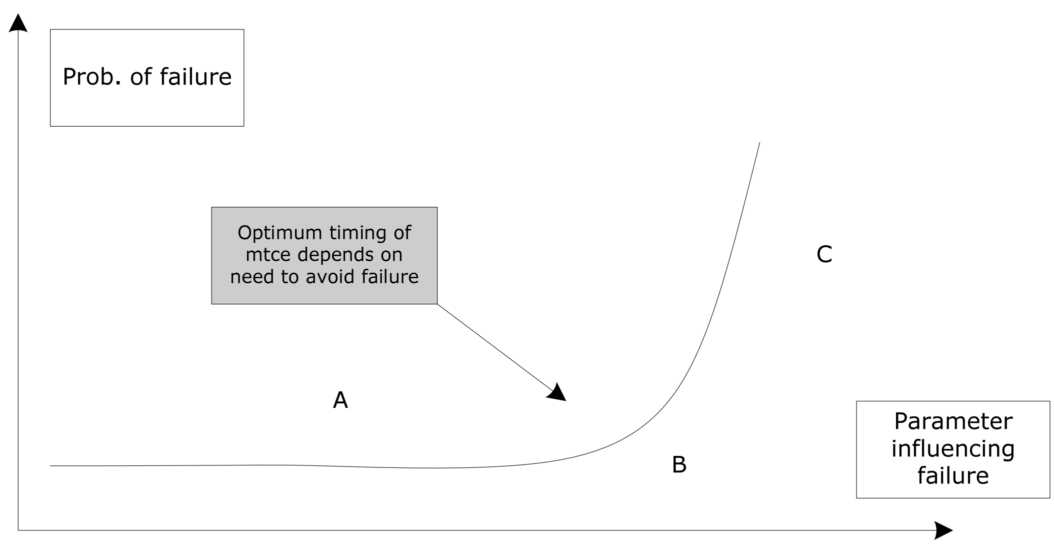
Asset category	Voltage trigger	Demand trigger	Temperature trigger
LV lines & cables	Voltage routinely drops too low to maintain at least 0.94pu at consumers point of supply. Voltage routinely rises too high to maintain no more than 1.06pu at consumers point of supply	Consumers' pole or pillar fuse blows repeatedly. Load imbalance Consumer complaint	Infra-red survey reveals hot joint. Conductor sag diminishes ground clearances Heating of grouped cables requires excessive de-rating

Asset category	Voltage trigger	Demand trigger	Temperature trigger
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 temp too hot, shortening life of transformer.
Distribution lines & 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	Infra-red 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 & 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
AEL equipment within GXP	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

6.2.2 Maintaining the Assets

As described in Table 6.2 maintenance is primarily about replacing consumable components. However, maintenance in its widest sense also includes for the regular inspection and condition monitoring of the assets, and the minor maintenance associated with these inspections, such as cleaning and maintaining protective coatings and housings of the assets. 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.

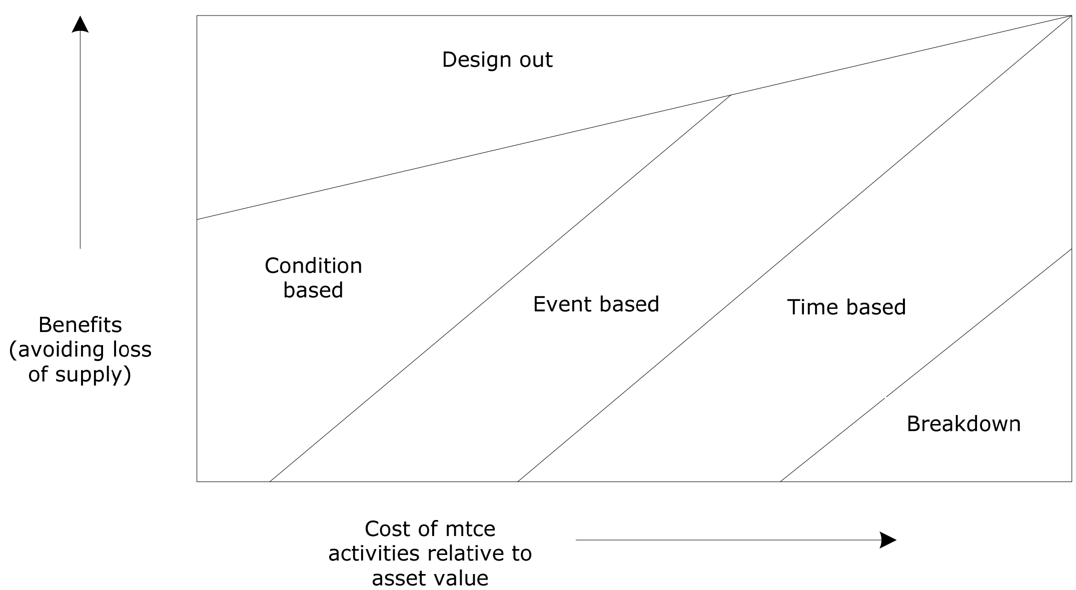
Examples of the way in which consumable components “wear out” include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts, wearing of pump seals, perishing of gaskets and pitting of insulators. Continued operation of such components will eventually lead to failure as indicated in Figure 6.2 below. Failure of such components is usually based on physical characteristics, and exactly what leads to failure may be a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, number of operations, loading cycle, stress to components due to fault current or over-voltage events, ambient temperature, previous maintenance history and presence of contaminants – note that the horizontal axis in Figure 6.2 can be but is not just related to time only.



- ***Figure 6.2: Component Failure***

Exactly when maintenance is performed will be determined by the need to avoid failure. For instance the need to avoid failure of a 10 kVA transformer supplying a single consumer is low, hence it might be operated out to point C in figure 6.2 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, say, turbine blades in an aircraft engine it would be desirable to avoid even the slightest probability of failure hence the blades may only be operated to point A. Modern protection relays and battery systems in Zone Substations are critical to the safe and reliable operation of the Network and may only be operated to point A. The 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 AEL's other business decisions, maintenance decisions are made on safety and cost-benefit criteria with the principal benefits being to avoid hazardous conditions and supply interruptions. The practical effect of this is that all assets which have a safety risk associated with them and assets supplying large customers or numbers of customers will be extensively condition monitored to avoid creation of hazards and/or supply interruption whilst assets supplying only a few consumers and which do not have particular safety risks associated with them, such as a 10 kVA transformer, will more than likely be run to breakdown. The maintenance strategy map in Figure 6.3 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 AEL relies less and less on easily observable proxies for actual condition (such as calendar age, running hours or number of trips) and more and more on actual component condition (through such means as DGA 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" 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 periodicity of the maintenance must be chosen to balance the risks and the effects of the outages.

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

- ***Table 6.5: Maintenance triggers***

Asset category	Components	Maintenance trigger
LV lines & cables	Poles, arms, stays & bolts	• Evidence of dry-rot. • Concrete fatigue/steel showing. • Loose bolts, moving stays. • Rusted hardware. • Displaced arms.
	Pins, insulators & 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 & 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 & bolts	• Evidence of dry-rot. • Loose bolts, moving stays.

Asset category	Components	Maintenance trigger
		• 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 (500kVA 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
	Switches & fuses	• Excessive oil acidity (500kVA or greater). • Visible signs of oil leaks. • Excessive carbon in oil • Visibly chipped or broken bushings. • Excessive moisture in oil • Poor resistance test of fuse • Corroded fuse carrier • Excessive rust. • Thermographic evidence of unusual heating of components and/or connections • Partial Discharge evidence of unusual current leakage in insulation
Distribution lines & cables	Poles, arms, stays & bolts	• Evidence of dry-rot. • Concrete fatigue/steel showing. • Loose bolts, moving stays. • Rusted hardware. • Displaced arms.
	Pins, insulators & 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

Asset category	Components	Maintenance trigger
		• 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
	Ground-mounted switches	• Excessive oil acidity (500kVA or greater). • Visible signs of oil leaks. • Excessive carbon in oil • Visibly chipped or broken bushings. • Excessive rust. • Broken or damaged hinges or cover fixings • Excessive moisture in oil • Poor resistance test of fuse • Corroded fuse carrier • Significant Partial Discharge detected • Thermographic evidence of unusual heating of components and/or connections
	Regulators	• Excessive oil acidity (500kVA or greater). • 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
Zone substations	Fences & 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, etc.
	Buildings	Secure, Waterproof, vermin & bird proof Fittings corroding Condition of paint & finishings

Asset category	Components	Maintenance trigger
	Bus work & conductors	Insulars chipped or cracked Burn or tracking marks Thermographic evidence of unusual heating of components and/or connections Loose droppers, Hot connectors. Earthing not intact and connected. Birds' nests
	33 kV switchgear	Unusual noises. Oil leaks Broken bushings Droppers loose Position indicator not legible Earthing leads not intact and connected Mechanism & 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 & 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 & trips not operating Bucholtz relay site glass not clean & containing oil OLTC not operating correctly Thermographic evidence of unusual heating of components and/or connections

Asset category	Components	Maintenance trigger
	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 & 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 annunciated/operating correctly Warning flags/lamps indicating faulty operation.
Sub-transmission lines & cables	Poles, arms, stays & bolts	Evidence of dry-rot. Concrete fatigue / steel showing. Loose bolts, moving stays. Rusting hardware. Displaced arms.
	Pins, insulators & 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

Asset category	Components	Maintenance trigger
		Obsolete conductor Significant Partial Discharge detected in cables Thermographic evidence of unusual heating.

Typical maintenance policy responses to these trigger points are described in Table 6.6 below. The frequency and nature of the response to each of the above triggers are embodied in AEL's policies and work plans. An outline of AEL's maintenance policies and work plans is given in Section 6.2.2.1.

- ***Table 6.6: Typical responses to maintenance triggers***

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

Asset class	Trigger	Response to trigger	Approach
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Condition as revealed by three yearly inspection
	Cracked or broken insulator	Replace as required	Breakdown
	Splaying or broken conductor	Repair conductor unless renewal is required	Condition as revealed by three yearly inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
Distribution 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
Distribution ABS's	Loose or displaced supporting components	Tighten or replace unless renewal is required	Condition as revealed by three yearly 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 three yearly inspection
	Rusty, broken or cracked enclosure where fitted	Make minor repairs unless renewal is required	Condition as revealed by three yearly inspection
	Oil acidity	Filter oil	Remove from service for full overhaul every 15 years
	Excessive moisture in breather where fitted	Filter oil	Condition as revealed by three yearly inspection
	Visible oil leaks	Remove to workshop for repair or renewal if serious	Condition as revealed by three yearly inspection
	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 5-yearly detailed condition assessment
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
LV lines	Loose or displaced	Tighten or replace	Breakdown unless

Asset class	Trigger	Response to trigger	Approach
	components		revealed by five yearly inspection
	Rotten or spalled poles	Brace or bandage pole unless renewal is required	Five yearly inspection
	Cracked or broken insulator	Replace as required	Breakdown unless revealed by five yearly inspection
	Splaying or broken conductor	Repair conductor unless renewal is required	Breakdown unless revealed by five yearly inspection
	Thermographic evidence of unusual heating	Repair or replace affected component	Condition as revealed by special inspection
LV Distribution & 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

6.3 Renewing Assets

AEL classifies work as renewal if there is no change (usually an increase) in functionality i.e. the output of any asset doesn't change. A key 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 e.g. 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 e.g. 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 e.g. "maintenance free for life" vacuum and SF6 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.

6.3.1 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 AEL 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.

6.3.2 Renewal triggers:

Table 6.7 below list AEL's renewal triggers for key asset classes.

- ***Table 6.7: Renewal triggers***

Asset category	Components	Renewal trigger
LV lines & cables	Poles, arms, stays & bolts	Condition based replacement
	Pins, insulators & binders	Condition based replacement
	Conductor	Condition based replacement
	LV distribution/link boxes	Condition based replacement
Distribution substations	Poles, arms & bolts	Condition based replacement
	Enclosures	Condition based replacement
	Transformer	Condition based replacement
	Switches & fuses	Condition based replacement
	Cable terminations, joints	Condition based replacement
Distribution lines & cables	Poles, arms, stays & bolts	Condition based replacement
	Pins, insulators & binders	Condition based replacement
	Conductor	Condition based replacement

Asset category	Components	Renewal trigger
	Cable Terminations, potheads, joints	Condition or age based replacement
	Ringmain switches, etc.	Condition based replacement
	Reclosers, Sectionalisers	Condition based replacement
	Regulators	Condition based replacement or maintenance costs exceed replacement
Zone substations	Fences & enclosures	Condition based replacement or maintenance costs exceed replacement
	Buildings	Maintenance costs exceed replacement
	Bus work & 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 & chargers	Age or Condition
	Instrumentation	Maintenance costs exceed replacement or equipment obsolete
Sub-transmission lines & cables	Poles, arms, stays & bolts	Age & condition based replacement
	Pins, insulators & binders	Age & condition based replacement
	Conductor	Age & condition based replacement
	Cable Terminations, potheads, joints	Condition or age based replacement
SCADA & Radio	SCADA, Radio, Ripple Control, & comms cables	Age & 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 & maintenance costs exceed the likely renewal costs.
- When continued maintenance is unlikely to result in the required service levels.

6.4 Up-Sizing or Extending Assets

If any of the capacity triggers in Table 5.2 are exceeded, AEL 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 & 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.

Despite the different nature of up-sizing and extension work, similar design and build principles are used as described in sections 6.4.1 and 6.4.2 below.

6.4.1 Designing New Assets

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

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

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

6.4.2 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.

6.5 Enhancing Reliability

Although enhancing reliability does not neatly fit into the life-cycle model, AEL believes that enhancing reliability is strategically significant enough in reshaping the business platform to merit inclusion in the AMP. As described in paragraph 4.2.1 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 go improving reliability just because it can be improved, even if AEL doesn't need to increase line charges to do it. However there are many factors that will lead to a decline in reliability over time:

- Tree re-growth.
- Declining asset condition (especially in coastal marine areas).
- Extensions to the network that increase its exposure to trees and weather.
- Increased 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.

AEL's 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. AEL expects the incremental cost of regaining lost consumer-minutes will accelerate away at some point which will set an obvious limit to implementing opportunities.

6.6 Converting Overhead to Underground

Conversion of overhead lines to underground cable is also an activity that doesn't fit neatly within the asset life-cycle because it tends to be driven more by the need to beautify areas rather than for asset-related reasons (which doesn't really fit the 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 Substations 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 AEL’s 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, AEL will be using the engineering definition of Risk as the product of the Probability of the Event and the Consequences of that Event (i.e. Risk = Probability of the Event x Consequences of the Event). Risk in this context is usually measured in dollars for the convenience of comparing the risks of competing options. Further and future discussion of this topic in the AMP will be undertaken in Section 7. “Risk Management”.

6.7 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 SF6, oil, lead or asbestos.

Key criteria for retiring an asset include:

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

6.8 Routine and Preventive Inspection, Maintenance and Performance Programmes

6.8.1 Maintenance Policies

Maintenance strategies are based on careful monitoring of asset 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 (e.g. station batteries), assets are not replaced based on age or other generic criteria and they are kept in service until such time as their continued maintenance is uneconomic or until they pose a safety or reliability risk.

Periodic inspections, patrols, servicing and test work is undertaken to ensure that defects or emerging risks are identified so that corrective work can be undertaken where required. Servicing can also involve minor component replacements (e.g. seals, bushings etc.), 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.

6.8.2 Maintenance Work Plans

The management of the maintenance of different types of plant is shared by various people within the AEL engineering office. This work is conducted in parallel with other engineering duties by most of these employees. A specialist Maintenance Manager was appointed in 2010 to assist the Asset Manager with the maintenance planning and management, and to take to over some of the maintenance projects that were undertaken by others prior to his appointment.

Overall the management of maintenance is the responsibility of the Asset Manager who sets the policies and procedures within the bounds of the AMP. The Asset Manager is also responsible for the yearly updating and editing of the AMP with the assistance of various other individuals and departments within AEL

The AEL maintenance work plans include routine visits by contractors to asset equipment for scheduled testing, inspection, cleaning, maintenance and minor repairs, with any major repairs requiring immediate attention being attended to in previously unscheduled visits.

Check sheets and reports from these routine 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 includes:

- for Zone Substations:
  - monthly checks and cleaning,
  - 6 monthly checks and minor maintenance, and
  - routine maintenance programs with periods and actions generally as specified by suppliers of the equipment or determined from experience or local conditions;
- for ground mounted Distribution Substations:
  - 6 monthly checks and minor maintenance,
  - routine equipment maintenance programs, and
  - special checks and maintenance (such as after heavy rain for underground subs);
- for all other Distribution Substations (pole mounted):
  - 5 yearly checks in association with their earth tests;

- Periodic system wide tests (such as partial discharge of circuit breakers and cables, and oil sample tests for transformers).

Unscheduled work includes:

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

6.8.2.1 Zone Substations, Ground Mounted Substations and Switchgear:

AEL has engaged NetCon Limited (AEL's wholly owned contractor) to prepare, maintain, and execute a comprehensive routine maintenance programme for all AEL's Zone Substations; ground mounted, underground and 2-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.

6.8.2.2 Overhead Lines and Associated Pole Mounted Equipment

In addition, NetCon undertakes overhead line patrols, pole inspections and line maintenance of AEL's 33 kV, 11 kV and LV lines.

These line inspection and maintenance works are directed by AEL, 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.

6.8.2.3 Partial Discharge Mapping of 11 kV Sub-transmission Cables

Partial Discharge 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 provided valuable asset condition information, particularly as concerns 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 be retested in a two yearly cycle from now on.

The 11 kV Sub-transmission cable mappings originally scheduled for 2012 have been rescheduled for 2013 due to the 11 kV switchgear replacement project at Grasmeres St Sub in 2012. Also in 2013, one off mappings will be done on two new 11 kV cables from NST feeding the Redruth area of south Timaru.

6.8.2.4 Partial Discharge Testing of Indoor and Ground Mounted Switchgear

A programme of Partial Discharge testing is undertaken of all indoor HV switchboards and outdoor ground mounted 11 kV switchgear. The tests are generally undertaken every 24 months 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 12 or 6 or 3 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.

6.8.2.5 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.

6.8.2.6 Tree Cutting and Vegetation Management

AEL conducts an active programme of tree cutting throughout the AEL region to keep trees away from existing lines and to clear trees (where possible) from the routes of new lines and extensions.

AEL employs 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 the AEL Asset Management Systems component of the IT Review project.

In the meantime, an "AEL Trees Log" spread sheet has been initiated (in 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.

6.8.2.7 Civil Type Maintenance

The following civil type maintenance services are provided by Netcon:

1. routine condition assessment of:
    a. Zone Sub buildings and non-electrical structures – monthly during sub checks;
    b. Dist. Sub buildings, kiosks, padmounts and enclosures – 5 yearly cycle, as part of overall condition assessment;
2. urgent reactive maintenance of:
    a. Zone Sub buildings and non-electrical structures - immediate;
    b. Dist. Sub buildings, kiosks, padmounts and enclosures - immediate;
3. planned routine maintenance of:
    a. Zone Sub buildings and non-electrical structures – 5-yearly cycle;
    b. Dist. Sub buildings, kiosks, padmounts and enclosures – 10-yearly cycle;

Civil type maintenance includes any non-electrical work not requiring an access permit, outside of the MAD, and associated with:

a. buildings, fences, enclosures, kiosks, external surfaces of padmount subs, etc.;
b. yard maintenance and weed control;
c. concreting and carpentry work;
d. cleaning, rust removal/treatment, and painting;
e. etc.

6.8.3 Defect Identification Processes

AEL's 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 AEL and subsequent reactive repair and maintenance work is scheduled.

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 AEL 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 six months. (Refer to Section 6.9 "Maintenance Plans" for a more detailed discussion of asset maintenance planning).

6.8.3.1 Special Condition Assessment Projects:

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

Also, AEL began 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 an AEL database. While the programme has had some delays, it is due for completion of the assessment phase in 2013.

This collected data will then be analysed by AEL engineers who will then instigate planned and coordinated maintenance actions to correct deterioration and defects found. The actions may be organised according to geographical area or a 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 AEL 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 partial discharge (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.

AEL plans to extend this type of special detailed condition assessment to all other HV Network plant, including Zone Substations, regulators, reclosers, etc.

6.8.3.2 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.

6.8.3.3 Future Maintenance Data Collection Methods:

Ultimately AEL envisages 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, AEL needs 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 AEL's proposed new, integrated, Asset Database and Management System and the contractor's systems.

6.8.4 (Refer elsewhere in this AMP for more detailed discussion on this topic of upgrading Asset Management Systems and Databases).Defect Rectification Process

When a 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:

- a safety risk to the public or employees, or
- endangers continuity of supply, or
- there is a risk of damage to Network equipment.

Minor defects may also be dealt with directly without immediate reference to AEL. In both the above cases the defects and actions would be reported to AEL after the action and AEL would approve and issue a maintenance order, as appropriate, to cover the actions taken.

Defects outside of either the above "risk to immediate safety" or minor maintenance criteria are referred by the contractor to AEL 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.

6.8.5 Routine Maintenance System

Table 6.9 summarises AEL's routine maintenance system:

Table 6.9: Routine Maintenance System

Asset Class:	Routine Maintenance Type:	Frequency:
Zone Substations	Monthly inspection and clean.	Monthly
Zone Substations	6 monthly detailed inspection, battery charger maintenance; plus 12 monthly earth testing and protection relay settings check & test.	6 monthly, with some items only 12 monthly.
Zone Substations	Detailed maintenance of equipment in accordance with the equipment suppliers' recommendations.	Annually for certain items, 2 yearly for others, and otherwise to supplier's recommendations
Ground mounted distribution substations and switches	Twice yearly inspection, MDI reading, minor cleaning/maintenance.	6 monthly, in Spring and Autumn
Ground mounted distributions substations and switches	Full maintenance of substation/switchgear, including cleaning, testing of oil/insulation, routine maintenance to equipment suppliers' recommendations.	5 yearly
Sub-transmission cables	Partial Discharge mapping	2 yearly.
Timaru 11 kV Sub-transmission switchboards (Grasmere St, Hunt St, & 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	6 to 12 months if condition warrants, otherwise every 24 months.
33 kV & 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.	5 to 10 yearly, according to condition based need.

Asset Class:	Routine Maintenance Type:	Frequency:
Pole mounted HV switches (recloser, sectionalisers)	Inspection and earth test. Minor in situ maintenance.	5 to 10 yearly, or more frequently if manufacturer, condition or age demands.
Regulators	Twice yearly inspection & clean. Minor in situ maintenance.	6 monthly
Regulators	Full maintenance including oil and operational tests; and associated equipment	5 yearly, or more frequently if specified by supplier.
Capacitors (11 kV line regulation type)	Inspect and test capacitance, check fuses; and maintain associated equipment.	5 yearly, or more frequently if specified by supplier.
Pole lines, including associated overhead fittings & equipment.	All lines older than 25 years (or younger if condition dictates), inspection of poles, line fittings, conductors, disconnectors, fuses, etc.	10 yearly, with scheduling based upon age and condition.

6.9 Maintenance Plans

This section discusses AEL’s maintenance plans and presents AEL’s maintenance expenditure projections.

6.9.1 Zone Substations

The 2013-14 budget for annual expenditure on zone substation maintenance is $830,000 per annum

Expenditure for power transformer maintenance and repair work has increased over the last five years due to two cases of gassing in power transformers, and 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 warrantee 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 at OPEX cost.

Prior to 2008, the Pleasant Point, Geraldine, Fairlie, 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, tested and serviced on a six monthly test and 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 bank 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.

Painting is carried out on a regular basis of generally between 10 to 15 years depending on site conditions. It is planned to paint one unit per year over the next ten years 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 is also carried out when a bulk oil circuit breaker has completed a specified number of fault clearances. Modern vacuum contactors require minor servicing and condition monitoring tests only 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, AEL's 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 re-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 Sub 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 Sub) 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 8 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.

6.9.2 Network Lines and Cables

The 2013-14 combined annual maintenance operations budget for network lines and cable maintenance (LV, Distribution, and Sub-transmission) is $3,654,000. This is split $562k for LV lines and cables, $3,024k for Distribution Lines and Cables, and $68k for sub-transmission lines and cables. (These amounts do not include renewal and upgrade expenditures which are in the capital budget).

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.

The 11 kV distribution lines and cables are typically 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 (e.g. irrigation and dairy areas), rural lines are also being 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.

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.

A continuation of the replacement program for outdoor circuit breakers (reclosers & sectionalisers, mainly 11 kV but including a few 33 kV) is planned with the emphasis on the older bulk oil units. Replacement levels will continue at five or six per year for the next 2 or 3 years.

6.9.2.1 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.

During the inspection, the line is carefully checked above ground and below ground for wooden poles. The aim is to identify and document all components that will not last for another ten years.

The below ground hard wood pole inspection involves removal of any decayed wood to establish the sound wood dimension. If the pole is found to be inadequate to support the safe working load, the pole is red-tagged for replacement within 3 months. Poles considered unable to last a further 10 years (based on rate of previous decay) are yellow tagged and details recorded on the pole inspection sheet for the line designer to program replacement within 5 years to afford a safety factor of 2.

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 ten-year planning period and the use of steel, fibreglass and laminated softwood 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, etc., 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.

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.

6.9.3 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 2013-2014 annual maintenance budget for distribution substations is $715,000 which includes inspection, assessment and repairs.

Distribution transformers are inspected, and earths tested every 10 years to comply with the Electricity Regulations. The distribution sub 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 (apart from the earth testing referred to above). For ground mounted distribution substations, the inspection and maintenance is typically carried out as a targeted separate project in a 5 yearly cycle until overdue maintenance is caught up. These substations are normally handled in groups, by geographical location or industrial site in order to minimise logistics costs. (The routine maintenance described here is separate from the special and detailed condition assessment studies referred to elsewhere).

11 kV RMU oil switches are still being targeted for more detailed maintenance. 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 sampled to ensure oil moisture and dielectric breakdown components are at acceptable levels and the oil switches remain safe and reliable.

At this stage the transformers are replaced if they are not expected to last another 10 years. It is becoming more economical to replace transformers smaller than 30 kVA rather than refurbishing them.

Equipment failures generally result from lightning strikes, cable termination failures and car accidents. Faulty transformers can generally be replaced within four – 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.

6.9.4 SCADA, Communications and Ripple Plants

The 2013-2014 maintenance budget for this equipment is set at $153,000per year. The SCADA system platform was replaced in 2006 as the earlier platform had reached the end of its serviceable life and obsolescence of hardware spares. The new system had improved functionality and reliability.

It was planned in 2010-11 to review the Master Station requirements during 2011-12. It was determined in 2011 that the SCADA Master Station's hardware platform required replacement due to the present equipment being over its economic life. However, it was also noted that further study was required to ensure present hardware replacements met any near future software upgrade needs.

Near future Master Station software upgrades may include expansion of the present SCADA 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 may be desirable to introduce a "whole network view" that may allow efficiencies in preparation, updating, and operational use of the company's network switching diagrams, but which may require significant upgrade to the present SCADA Master Station software.

The Radio system is reaching end-of-life determined by equipment age, reduced support from manufacturers and obsolescence of technology and is now replaced by microprocessor controlled technology. Therefore the 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 2-3 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. 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 to 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 2-4 years. Routine replacements of d.c. power supply batteries, the replacement of minor systems, alarms and security systems are also allowed for.

The integrity of the SCADA hardware and software systems is of the highest importance to the on-going management and safety of the network. The SCADA 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 three-year period due to obsolescence of the present equipment. Similarly, the main UHF radio equipment is reaching 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.

6.9.4.1 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 has been consider advisable to review the whole SCADA Master Station and Communications set-up. This is due to the existing possibility that the Control Room, and by extension the Equipment Room, can be relocated to a proposed new Washdyke Zone Substation site. In addition, significant upgrades to the capabilities of the Master Station may be required within the next few years.

In the mean-time, in order to maintain adequate SCADA System reliability, it is proposed to upgrade the SCADA Master Station's computer hardware as a first stage of the original Washdyke Communications Room upgrade project.

6.9.5 Maintenance Expenditure Projections

Table 6.10 below lists the projected maintenance expenditure by asset class for the period 2013-2023.

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 & Cables,

- growth in maintenance expenditure following an “S” curve with the growth beginning to taper from about year 1 (2013-14) and plateauing about year 6 (2018-19),
- presumed “S” curve reflecting the elimination of the most urgent cases from the 15 years of “deferred” network maintenance prior to about 2008,
- “S” curve also reflecting the presumed 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 on the NetCon resource to undertake both AEL maintenance and capital works over the period,
- limitations imposed by AEL Operations on network access (outages and switching) for maintenance intervention.

However, caution needs to be exercised as some of the above assumptions of reducing 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 (e.g. OPEX equipment refurbishments that do not fall into renewal or upgrade CAPEX categories).

Table 6.10: Maintenance expenditure by asset category

Asset Category	Annual Budget for 2013/23 (in $'000)										
	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
LV Lines & Cables	562	503	503	514	518	519	519	522	522	512	512
Distribution Substations	715	1,097	1,097	1,121	1,130	1,134	1,133	1,139	1,139	1,118	1,118
Distribution Lines	3,024	2,914	2,913	2,976	2,999	3,010	3,008	3,026	3,025	2,969	2,969
Zone Substations	830	559	559	571	576	578	577	581	581	570	570
Subtransmission	68	67	67	69	69	70	70	70	70	69	69
SCADA & Radio	153	209	209	214	216	216	216	218	218	213	213
Unspecified	1	1	1	1	1	1	1	1	1	1	1
TOTAL	**5,353**	**5,351**	**5,348**	**5,464**	**5,507**	**5,527**	**5,522**	**5,556**	**5,555**	**5,451**	**5,451**

6.9.6 Renewal & Up-sizing Capital Expenditure 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 Refurbishment, and
- Up-sizing (or Upgrading),

which 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.

6.9.6.1 Assets for Replacement and Renewal

Table 6.11 summarises the asset replacement and renewal budgets by asset category for the 2013-23 period.

- ***Table 6.11: Asset Renewal and Refurbishment Budgets for 2013-23:***

Asset Renewal & Refurbishment										
Project Category	**Annual Budget for 2013/23 (in $'000)**									
	13-14	**14-15**	**15-16**	**16-17**	**17-18**	**18-19**	**19-20**	**20-21**	**21-22**	**23**
Distribution Lines & Cables	290	297	303	310	318	325	332	340	348	356
Distribution Substations, including transformer, regulators, ring main units, etc.	760	738	708	728	792	742	742	742	742	680
Zone Substations	1,115	965	175	100	250	100	100	100	250	100
SCADA, Comms, & load control plants	838	200	-	-	-	-	-	-	-	-
Total Asset Replacement & Renewal Projects Expenditure:	3,003	2,200	1,186	1,138	1,360	1,167	1,174	1,182	1,340	1,136

7.

Risk Management

7.1 Risk Management

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 the third dimension of the control 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 more money to reduce the specific risk and the money would be better directed towards the control of higher risks.

Alpine Energy have adopted the guidelines for managing risk which are described in AS/NZS/ISO 31000: 2009 “Risk Management – Principles and Guidelines”

AS/NZS/ISO 31000: 2009 “Risk Management – Principles and Guidelines” prescribes a process for risk management involving the following steps:

- Establish the Context
- Risk Identification
- Risk Analysis
- Risk Evaluation
- Risk Treatment
- Monitoring and Review

Alpine Energy’s network is exposed to a range of internal and external elements that can have an impact on their 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.

As this standard has 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 2013-14 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.

AEL maintenance program include routine inspections to ascertain asset condition and regulatory compliance.

These policies rank public and environmental safety as a top priority.

7.1.1 Risk Criteria

Linked to AEL's mission statement of providing safe, efficient, reliable and cost-effective energy delivery, the risk criteria of Safety, Efficiency, Reliability and Cost Effectiveness are important drivers as well as legal and regulatory requirements which are assumed requirements.

The objectives below are considered in conjunction with the probability and severity of events that prevent the objectives being successfully realised:

Business Objective	**Risk Criteria / Standards:**
Safety:	Public Safety
	Workplace Safety
	Network Operating
	Livestock Safety
Efficiency:	Network Operating
(doing things right)	Network Design

	Human Resources
Reliability:	Network Operating
	Restoration Plans
	Contingency Plans
	Emergency Preparedness
	Maintenance / Renewal Plans
Cost Effective:	Societal Cost
	Business Cost
	Regulatory Cost
	Legal Cost

The likelihood of interruption to energy delivery is a primary risk and its severity depends on where in the hierarchy of network assets the event takes place. The loss of a zone substation transformer can affect thousands of consumers for 24 hours, while a pole transformer may only affect a single dwelling for four hours. Similarly, a 33 kV sub-transmission line fault may drop supply to an isolated rural zone substation with a single transformer for a few hours, but a fault in that same lone 33/11 kV power transformer may lose power to the same consumers for one or more days until a replacement is sourced, transported to site, and commissioned. This is one of the drivers for the AEL mobile substation.

7.1.2 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.

AEL is 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 through floods, high winds, lightning, snow, earthquake, tidal wave and fire. There are aspects of the selection and installation of network equipment that minimises CFC 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 power lines, operating plant or stockpiling material without adequate clearances from line equipment, lighting fires adjacent to power lines, moving irrigators under live line, 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 lines.

7.1.3 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 Alpine Energy's business.

AEL has 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. The following qualitative measures of likelihood have been used in the AEL 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

The following qualitative measures of consequence or impact have been used in the AEL risk assessment (descriptors have been revised since the previous AMP to be the same as ISO/IEC 31010, as referenced in AS/NZS/ISO 31000-2009, section 5.4.1):

- *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 Co's 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

Combining the qualitative assessment of consequence and likelihood provides a level of risk matrix (based on ISO/IEC 31010,)

- *Table 7.3: Risk Matrix*

Qualitative risk analysis matrix—level of risk						
Likelihood		**Consequences**				
		Minor	**Important**	**Serious**	**Major**	**Catastrophic**
		0.5	**1.0**	**1.5**	**4**	**5**
5	Almost Certain	M	H	H	E	E
4	Likely	M	M	H	V	E
3	Possible	L	M	H	V	V
2	Unlikely	L	M	M	H	V
1	Rare	L	L	L	M	H
E = extreme risk; immediate action required						
V = very high						
H = high risk; senior management attention needed						
M = moderate risk; management responsibility must be specified						
L = low risk; manage by routine procedures.						

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

Quantitative analysis is used where specific performance measures are in place, i.e. Oil sample testing of zone substation transformers. This technique provides a review of compounds in the oil sample to determine the health and position along its age curve based on known operating history. This allows management of the higher cost (consequence) 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 Low Voltage 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.

The following table summarises the qualitative results for the level of risk at Alpine Energy substations after applying the risk matrix for likelihood and consequences for each listed event.

(* Note: the levels of risk summarised in Table 7.4 and Table 7.5, below, are still based on the previous AS/NZS 4360-2004 Guidelines. The two tables will be updated once the risk assessments based on the new ASNZSISO 31000 and its associated ISO/IEC 31010 guidelines have been completed).

▪ ***Table 7.4: Risk Level at AEL Substations***

Level of Risk at AEL Substations for Identified Risk categories (* see Note, above)																
Site	**Loss of Substation Transformer**	**Protection maloperation**	**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
Bells 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

Level of Risk at AEL Substations for Identified Risk categories (* see Note, above)																
Site	Loss of Substation Transformer	Protection maloperation	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
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

Qualitative risk analysis — level of risk at AEL Substations

E = extreme risk; immediate action required

V = very high risk;

H = high risk; senior management attention needed

M = moderate risk; management responsibility must be specified

L = low risk; manage by routine procedures.

- ***Table 7.5: Risk Level by AEL 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
33kV Cables	H	H	H	M	M	H	H	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11kV 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	-	-	-	-	-	-	-
11kV Dist Cables	L	L	L	M	M	H	M	M	M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dist Transformers (OH)	-	-	-	-	-	M	-	-	-	-	-	-	-	-	-	-	-	-	-	M	L	L	-	L	L	-	L	-	-
Dist 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 Under ground cables	L	L	L	L	L	L	L	L	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LV Distribution Boxes	-	-	-	-	-	L	-	-	-	-	-	-	-	-	-	-	-	M	-	L	-	-	-	-	L	L	M	M	M

7.1.4 Risk Evaluation and Treatment

Further review of the outcomes from the above risk analysis table identifies the loss of a substation transformer at a single transformer 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.

AEL's mobile sub is expected to be available for deployment by 2014-15.

Previously, protection maloperation at Hunt & 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 the new AEL 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.

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.

A high risk level had been identified at Grasmere St and the two Clandeboye substations. The new 11 kV switchboard at Grasmere St, due to be commissioned by 31/03/2013, will lower 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 is 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 Huntand 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 (2010) will reduce co-ordination and discrimination problems. Procedures for operating at Clandeboye need regular enforcement 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 subtransmission cable 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 bank 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 H and M to L, except that the existing (2008) Pareora Sub 11 kV switchboard risk has only been lowered from H to M 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 switchrooms (one for each half bus) do have arc flash containment and ducting to the exterior and so are rated a risk of L.

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 containment and is in separate buildiing from the older T1 11 kV switchboard which does not have arc flash protection nor containment.

Snow and Wind typically create high risks in the Mackenzie area of the network. Designs standards are employed to ensure adequate strength of materials are used to meet the demands of extreme weather events.

The 11 kV switchroom 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 AEL's 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 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.

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 2 of 3 transformers cannot carry peak load.

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

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.

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.

7.1.5 Risk Treatment

Table 7.5 above summarises the qualitative results for the level of risk for the remaining Alpine Energy 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:

The 33 kV cables have high risk across the range of AEL 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 subtransmission cables but withb 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 AEL attention for the reduction of risk as this will be made feasible as part of feeder upgrades driven by load growth.

Earthquakes form the highest risk across the range of asset categories. The potential for an earthquake is possible; however the impact has potential to be severe on buried assets.

Further work is required to fully assess the vulnerabilities of buried cable systems and this will be completed in conjunction with the 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 are readily available from suppliers. The higher voltage cables have the highest impact on system reliability and restoration of supply should damage occur.

AEL controls 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 Alpine Energy when danger to the public is identified. AEL has also had meetings with the contractors presently working in the area building the UFB fibre project to assist them in avoiding damage to AEL's underground assets during their excavations and thrust boring operations.

Internal risks are mitigated by establishing policies and procedures which meet the objectives of the company as well as regulatory requirements for Occupational Health and Safety, Emergency Preparedness (CDEM), and compliance with statutory Acts and Regulations.

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

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 require excavating 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.

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.

Low Voltage 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 is maintained.

Low voltage 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 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.

7.1.6 Risk Management Improvements

Plans to improve the management of risk 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. This is a legislative requirement of both the Health & Safety In Employment Act 1992, and Electricity (Safety) Regulations 2010. Therefore dedicated engineering and management resources will need to be allocated to this task.

There was a strong reliance on the contractor’s stock levels being maintained with AEL 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 AEL’s 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 AEL’s 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 AEL, will review quantities and re-order levels annually.

Earthquakes have been identified as a high risk category. There needs to be a survey of distribution equipment to ensure that seismic restraint practices are being maintained.

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 plantwith sufficient injection power capacity and an adjustable filter to enable its use at any of the AEL 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 AEL has a policy cover on major substation equipment.

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

On 24th November 2009 at 0455 hrs 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 Alpine Energy re-structured its network operations 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.

(Note: Most outages on AEL's network are caused by events that, as a class are quite likely to occur during the course of any year, such as: wind storms, snow storms, lightning, car hits pole, swan hits line, excavation contractor hits cable, etc,, but which may have a very low likely hood as far as a particular item of equipment is concerned. However, 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 AEL's 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).

7.1.8 Network Capacity

It is AEL 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 the AEL capital investment criteria, or be funded wholly or in part by the customer.

7.1.9 Operational Security

Capital investment for network security is evaluated based on the:

- Estimated cost to customers of energy not supplied.
- 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.

Present projects designed to enhance operational security are included in section 5.7.

7.1.10 Environments

AEL 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 AEL, 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 AEL 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. AEL develops 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.

7.1.11 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.

7.2 Health and Safety

Safety is determined by a combination of:

- asset design
- maintaining the assets in a safe condition
- safe operating and work practices

The Electricity (Safety) Regulations 2010, which came into force on 01 April 2010 have been subsequently amended by the Electricity (Safety) Amendment Regulations 2011, and Electricity (Safety) Amendment Regulations 2012, which comes into force on 1st July 2013.

This has necessitated regular reviewing and updating of the Health & Safety Management System; and many other facets of AEL's operational procedures and technical processes.

7.2.1 Public Safety

The Electricity (Safety) Regulations 2010, and 2011 and 2012 Amendments, contain the framework for the AEL policy on safety related asset management. The Regulations are mainly performance based, rather than prescriptive. AEL has adopted the concept of working as a reasonable and prudent operator as a guide to safe asset management practices. Industry-developed safe operating and work practices are being established.

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 Workplace Safety

The Health and Safety in Employment Act 1992 and subsequent amendments is a key item of safety legislation impacting on AEL. The purpose of this performance-based Act is to prevent harm to employees and others in the work place, and promote excellence in safety management. While not overriding safety requirements found in other Electrical Acts and Regulations, the Act has far reaching impact. Compliance is achieved by duties set on all parties associated with design, construction, maintenance and operation of AEL network assets.

Occupational health and safety is addressed through application of the Health and Safety Management System, and the network authorisation process for contractors operating on the network.

7.2.3 Safety Management System

The Electricity (Safety) Regulations 2010 require all electricity distribution companies to produce a Public Safety Management System, which is required to be in place and audited by the Electricity Authority before 1 April 2012.

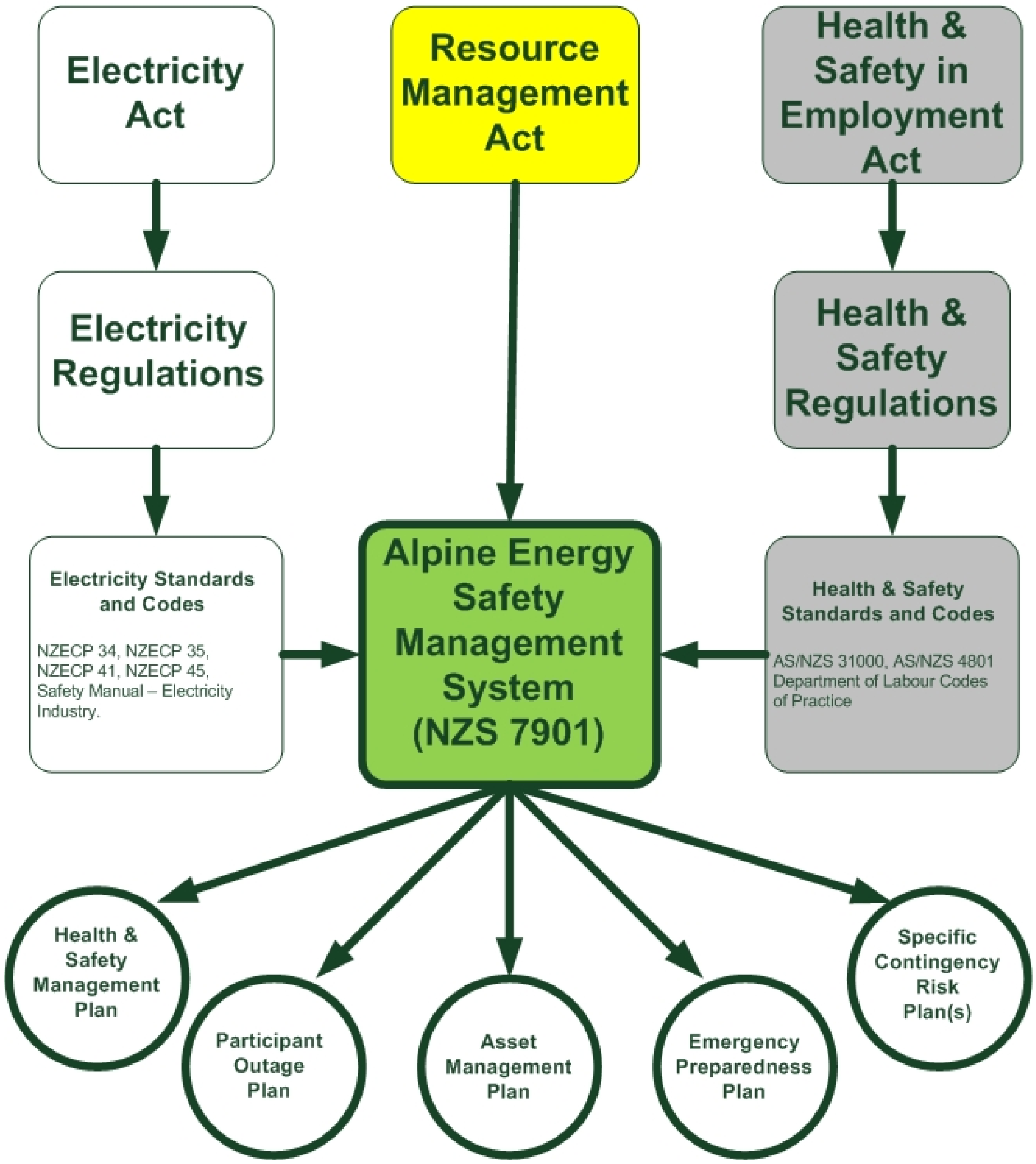
AEL's integrated Safety Management System has been audited, and is certified to comply with both the requirements of NZS7901:2008 Electricity and Gas Industries - Safety Management Systems for Public Safety, and the requirements of AS/NZS 4801:2001 Occupational Health and Safety Management Systems.

The integrated Safety Management System (SMS) includes, but is not limited to, the: Health & Safety Management System, Emergency Preparedness Plan, Participant Outage Plan, Civil Defence Emergency Management, and various specific contingency plans.

The SMS also interfaces with other company systems, such as the Asset Management Plan.

The Electricity Authority has indicated that there will be a large emphasis placed on improving physical security of assets; as well as a higher expectation on improving Standard Operating Procedures that relate to emergency processes, and post incident re-livening of assets.

This necessitates the dedication of significant financial resourcing (see Works plan) as well as staff time to complete this project within the timeframe dictated by the Electricity Authority.



- *Figure 7.1: Safety Management System Framework*

7.3 Emergency Response and Contingency Planning

AEL recognises that the local economy depends on a secure and reliable supply of electricity, and that catastrophic natural events, including earthquakes, landslides, tsunami, floods or snow storms, can have significant impact on both the AEL network, and the local economy.

AEL has developed emergency response plans for dealing with widespread abnormal situations created by either equipment failure or catastrophic natural events.

Mutual Assistance Agreements have been implemented with sister electricity distribution networks – these were last activated in the Christchurch Earthquakes September 2010 and February 2011, AEL's contribution was mostly logistical (including re-deployment of Transpower's 11 kV switchboard to Bromley Substation rather than it's 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 learning 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.

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

An example of this is the 'Network Status' page on the recently completed upgrade of the AEL website which shows real-time status reports and outages.

All emergency response plans are regularly reviewed to ensure that unique risks arising from emergency response have been identified.

Our wholly-owned subsidiary contracting company NetCon provides 24 hour 7 day response service (on direction from AEL's 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.

Alpine is 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 has been redistributed to Alpine Energy staff as part of AEL's Health & 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 SF6 Release
- Pandemic

7.3.3 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.

AEL 's 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 Participant Outage Plan can be found on our website: www.alpineenergy.co.nz.

7.3.4 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 & T8 (both 220 kV circuits)' which has been developed jointly with Transpower to ensure electrical supply continuity to the Fonterra Clandeboye dairy factory.

7.3.5 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 the AEL Control Room.

AEL was 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, AEL participates in the development of both regional and local Civil Defence Emergency Management plans, and provides technical advice to Local Authorities and other Lifeline Utilities as requested.

AEL participates 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 2 tsunami threats to the South Canterbury coastline, and AEL's response to the Christchurch Earthquakes.

8

Evaluation of Performance

This section presents a review of AEL's performance against the set reliability and financial performance targets for year–end 2012.and secondly, identifies areas where AEL believes it could improve its business.

8.1 Network Reliability Performance

All market segments have clearly indicated that supply reliability (the combination of continuity and restoration) is what is most important to them. AEL therefore considers supply reliability the most important parameter to measure. A Summary of previous years' reliability as measured according to the definitions of SAIDI and SAIFI as detailed in section 4 is listed in Table 8.1 below. These are actual numbers and "Major Event Days" are not normalised.

- *Table 8.1: Performance Summary – SAIDI, SAIFI and CAIDI (2002 – 2012)*

YEAR	SAIDI	SAIFI	CAIDI
2002/3	202	1.1	181
2003/4	125	1.6	76
2004/5	79	1.1	74
2005/6	80	1.3	63
2006/7	1110	1.9	594
2007/8	149.50	1.69	88.46
2008/9	200.94	1.69	118.76
2009/10	332.36	2.18	152.46
2010/11	225.92	1.71	132.11
2011/12)	161.60	1.26	128.14
2012 to 31/01/13	129.88	1.10	117.54

Details of the performance figures for the years 2002/3 to 2010/11 can be found in the respective AMPs. The performance figures for 2011/12 will be analysed in more detail in the following paragraphs. Table 8.2 below lists the breakdown of the performance figures against targets for the planned and unplanned contributions on AEL's- and Transpower's networks respectively.

- *Table 8.2: Performance Summary – SAIDI & SAIFI, 2011/12 Financial Year*

Parameter	Target 2011/2012	Actual 2011/2012	Remarks
Planned SAIDI – Class B	60	54.30	
Unplanned SAIDI – Class C	108	107.30	
Planned SAIFI – Class B	0.26	0.25	

Parameter	Target 2011/2012	Actual 2011/2012	Remarks
Unplanned SAIFI – Class C	1.10	1.01	
33 kV faults per 100 km	-	0.82	o/h only as no u/g faults
22 kV faults per 100 km	-	5.49	o/h only as no u/g faults
11 kV faults per 100 km	-	4.62	incl. o/h & u/g faults

The planned outages resulted in 54.30 SAIDI and 0.25 SAIFI minutes and are both within the targets of 60 and 0.26 respectively.

The planned outage activity is driven by a need to do maintenance work which relates to the general condition of the network which is stretched as a result of the rapid growth that was experienced in recent years. The majority of customer connections are undertaken using a combination of Live Line Glove and Barrier techniques and level 1 Live Line sticking work (live line clamps) to avoid planned outages.

Vegetation management has been and remains a challenge due to owner's emotional attachment to their trees, hedges etc. This is however a concern for AEL based on the number of outages and SAIDI minutes attributable to debris from trees being blown into AEL lines. Unfortunately 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" which only considers clearances from trees in calm weather conditions. Theses distances are 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. The growth limit zone distance of no growth within 1.6 meters of an 11kV line in such circumstances is of absolutely no benefit to distribution companies and their attempts to manage reliability.

The AEL unplanned outages of 107.30 SAIDI and 1.01 SAIFI minutes, were within the target of 108 SAIDI, 1.10 SAIFI minutes. The breakdown contribution of unplanned outages to the overall SAIDI minutes can be summarized as depicted in Table 8.4 below:

- ***Table 8.4: Summary of Unplanned Outages' contribution to SAIDI minutes***

Unplanned Outages(11/12)	
Cause of Fault	**SAIDI Minutes**
Natural	13.5

Human Error	38.78
Faulty Equipment	24.65
Underground Cables	8.9
Vegetation	4.42
Wildlife	3.52
Broken Conductors	1.9
Other	3.3
Unknown	8.35
TOTAL	**107.30**

The percentage contribution of all factors affecting the SAIDI minutes lost for unplanned outages for 2011/12 is shown in Figure 8.1.

This year, an analysis of the unplanned SAIDI minutes shows the largest contribution of 25% related to faulty equipment. This is followed by the “Human Error” factor which contributed 22% to the total SAIDI minutes lost. The main contributor in this category “Human Error” category this year was farm and contractor vehicles hitting poles, stays, or lines resulting in outages.

Whenever such an accident is fatal, the scene is not released by the police until their investigation is fully completed. This results in extended outages before the network is repaired. In addition to vehicles into poles, owners cutting trees and branches which end up in AEL’s lines are also a significant contributor. AEL does sensitise the public to the dangers involved in tree felling through a regular advertisement in the local newspapers with contact details for assistance in this regard.

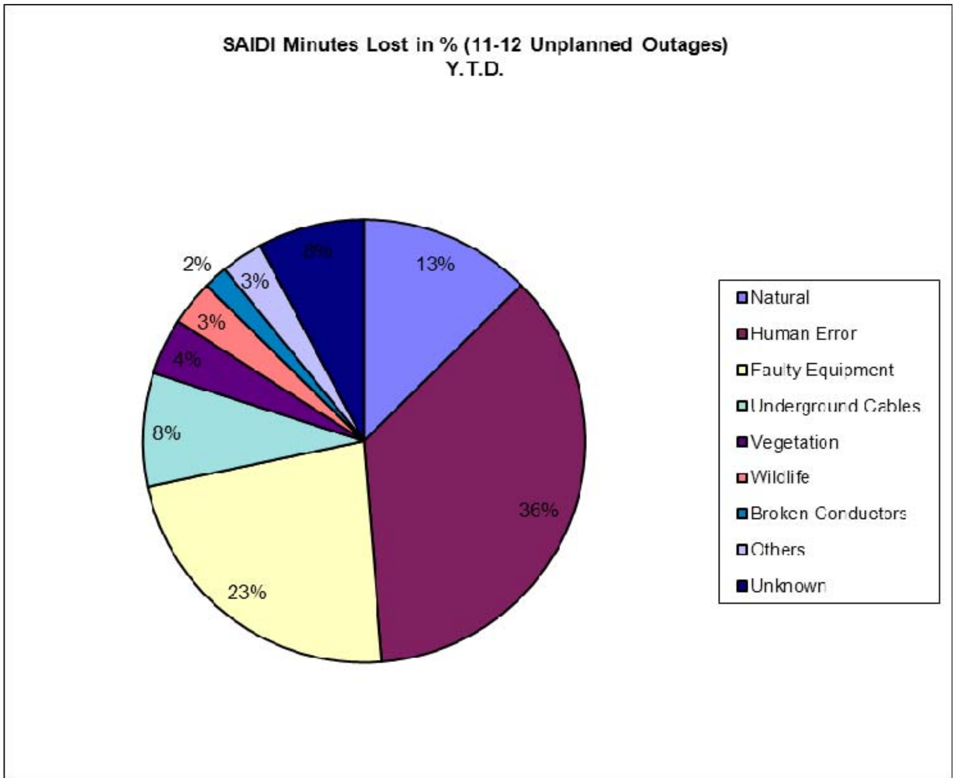
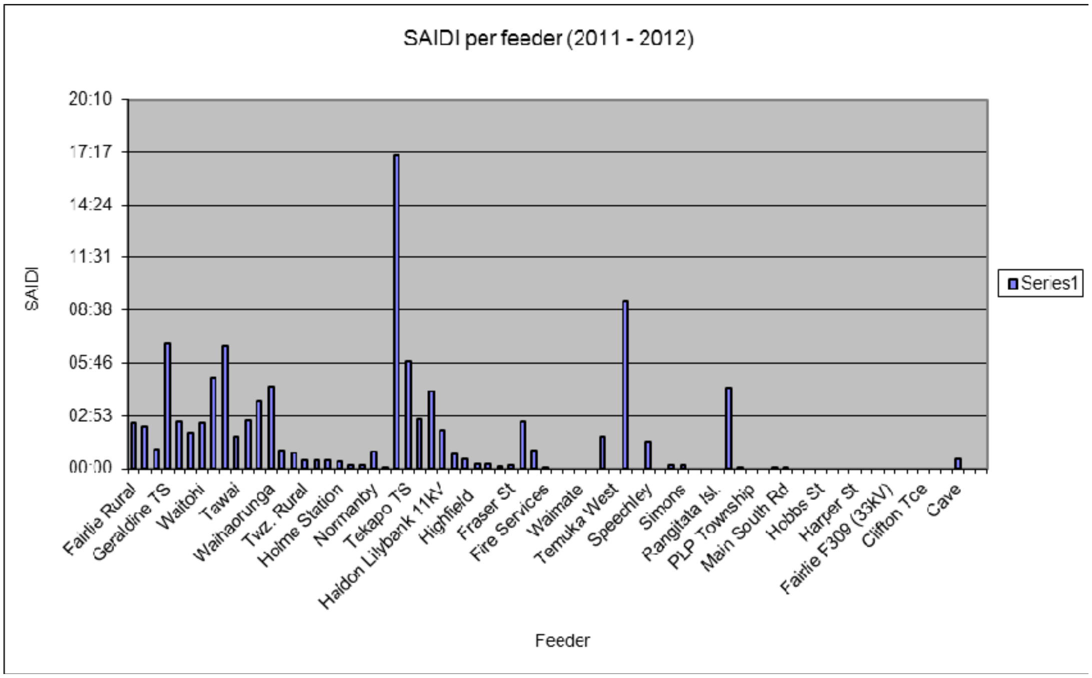


Figure 8.1: SAIDI Minutes contribution

Figure 8.2 depicts the ten worst performing feeders in relation to SAIDI minutes for the 2012/13 period. Feeder performance with respect to number of outages is also listed in Table 8.5.



▪ ***Figure 8.2: SAIDI minutes per feeder – Unplanned Outages***

The ten worst performing feeders in 2012/13 year with respect to outages, SAIDI minutes lost and causes are detailed in the following Tables.

▪ ***Table 8.5: The eleven worst performing feeders by Outage***

FEEDER	No. of outages	SAIDI	SAIFI
Fairlie Rural	11	2.53	0.02
Winchester	10	6.72	0.09
Waitohi	9	2.5	0.03
Morven	8	1.05	0.01
Levels / Mt View	8	2.57	0.02
Haldon M142/M200 (22kV)	7	2.33	0.02
Waihaorunga	7	4.45	0.05
Geraldine TS	6	6.83	0.14
Woodbury	6	4.92	0.04
Otaio	5	1.88	0.03
Rolleston	5	2.65	0.02

Table 8.6: The ten worst performing feeders by SAIDI minutes

FEEDER	No. of outages	SAIDI	SAIFI
Opuha F329 (33 kV) (caused by 11 kV fault)	1	17.13	0.04
Suburban / Doncaster*	2	9.17	0.04
Geraldine TS	6	6.83	0.14
Winchester	10	6.72	0.09
Tekapo TS	1	5.88	0.02
Woodbury	6	4.92	0.04
Waihaorunga	7	4.45	0.05
Geraldine Sub 11 kV LOS	1	4.43	0.08
Mt Cook 33 kV	2	4.18	0.01
Alpine Energy	4	3.67	0.04

Table 8.7: The ten worst performing SAIDI feeders by interruption cause in the 2012/13 financial year

FEEDER	Broken Cond.	Faulty Equip.	Human Err.	Natural	Others	Underg. Cables	Unknown	Vegetation	Wildlifes	Total
Opuha F329 (33 kV) (caused by 11 kV fault)	0	0	17.13	0	0	0	0	0	0	**17.13**
Suburban / Doncaster*	0	9.17	0	0	0	0	0	0	0	**9.17**
Geraldine TS	0	0	2.7	4.13	0	0	0	0	0	**6.83**
Winchester	0	0	3.88	2.62	0	0	0.22	0	0	**6.72**
Tekapo TS	0	5.88	0	0	0	0	0	0	0	**5.88**
Woodbury	0	4.02	0.47	0.43	0	0	0	0	0	**4.92**
Waihaorunga	0	0.42	2.43	1.0	0	0	0.6	0	0	**4.45**
Geraldine Sub 11 kV LOS	0	0	4.43	0	0	0	0	0	0	**4.43**
Mt Cook 33 kV	0	0	0	4.18	0	0	0	0	0	**4.18**
Alpine Energy	0	3.67	0	0	0	0	0	0	0	**3.67**

*(Note *: Suburban/Doncaster Feeder existed before the new Transpower switchboard was commissioned in 2012. This feeder is now the Meadows Road Feeder).*

The worst performing feeder by outage was Fairlie Rural which had a total of 11 outages. However the worst performing feeder by SAIDI minutes was Opuha F329 (33 kV) with 17.13 unplanned SAIDI minutes caused by an 11 kV fault (due to a farm worker's human error). The 11 kV fault (stay wire flicked up into line) resulted in the tripping of the Opuha Power Station while the supply from Albury GXP was off to allow Transpower to replace its 11 kV switchboard at Albury.

Suburban / Doncaster feeder had two unplanned outages contributing 9.17 SAIDI minutes due to faulty equipment (a cracked insulator, a faulty transformer). Of the six faults on the Geraldine Township feeder, two were due to human error (digger hit pole, tree felled through line) contributing 2.7 SAIDI minutes, and four were due to natural causes being mainly wind related contributing 4.17 SAIDI minutes.

The 6.72 SAIDI minutes lost on the Winchester feeder were the result of ten outages that were shared between three human error faults (3.87 minutes), two natural cause faults (2.62 minutes), and five unknown cause faults.

All interruptions greater than 1 SAIDI minute are reviewed and reported to directors as part of monthly board reporting.

8.2 Financial Performance

Financial performance for the 2012/13 year is summarised in Table 8.8 below:

- ***Table 8.8: Financial performance***

Parameter	Target ($000)	Actual ($000)
Line revenue	35,400	33,747
Operational spend on Assets	5,050	4,094
Capital spend on Assets	20,568	18,056

The 2011-12 year saw an increase in customer connections from forecast. AEL resources were reinforced in this area to meet the growing demand. This resulted in a reduction in resources previously allocated to Operational Expenditure.

Capex expenditure was down by approx. $ 2.5 M from forecast due to heavier contractor weighting compared to equipment component and hence the resource constraint having greater influence than forecast.

8.3 Works Implementation Performance

8.3.1 New Assets

The under expenditure on the CAPEX budget was mainly due to resource constraints and access to the network. The main contributors to the under expenditure were as follows:

- Recloser replacements ($220k).
- Zone substation protection replacements ($197k).
- RMU replacements and unidentified new RMU's ($272k).
- Pareora transformer refurbishment ($150k) was not spent due to the late completion of the transformer replacement project.
- The quote for the transformer purchased for Rangitata substation was some 20% below the budget and the delivery delayed to the next financial year resulting in a $750kunder expenditure.

In contrast, there was over expenditure (+15.8%) in the customer connection area:

- New Connections, subdivisions & extensions (+ $ 362k). This budget is very much dependant on the number of new connection applications received. This was up by + 15.8% on expected mainly due to the growth in the irrigation sector.

8.3.2 Existing Assets

Maintenance spend was down on budget by approximately 19% due mainly to competition from CAPEX projects for available contractor resources.

As reported last year, it is expected that implementation of a propriety type asset management and works management system will greatly enhance maintenance planning and efficiency. The previously mentioned IT review process has identified shortcomings and proposed an "off the shelf" type system to be implemented.

AEL has recently (2011) implemented a new financial system which will make reporting and assessment more automated and efficient from next year on.

AEL will continue dedicating resource to identify and implement areas for performance improvement.

8.3.3 Processes & Systems

The system of processing, storing and analysing the data collected during site inspections requires review and improvement. The improvements required involve upgrading AEL's databases and asset management systems, and more efficiently interfacing the AEL and contractor data systems (including automation of entering and transfer of electronic data).

The current systems, the data held, and how the data is used is described in Section 2.8.

AEL embarked on an Information Technology Review where Deloitte was employed to assess and evaluate all IT infrastructure and systems at a high level and comment on it. This exercise also included visits to other distribution companies to learn from them and their experiences with their systems and the implementation of new systems.

Following the amelioration of the database systems, a new Asset Management System will be required to improve the efficiency and usefulness of the databases and the asset data, and consequent management of the assets.

- *Table 8.9: AEL Systems Data Management & Maintenance*

System	Process	Progress	Remarks
GIS Field Capture	All Poles	Complete	GPS used for data capture
GIS Field Information	All Network sites, plant & equipment – system is manual processing in office of new job pack & update information.	Partial (corrections required to some old sites and addition of all new ones)	The inevitable gap between actual and recorded state is closing as DO staff catch up with processing new sites & updating old ones.
Asset Base Data	Various old legacy databases and systems	Partial (some fields empty, even for corrected and new sites)	Upgrade with a dedicated Asset Management System (AMS)to be studied.
Asset Maintenance Data	Combination of manual systems, spread sheets and paper based records	Partial (basic data on paper held by NetCon)	Upgrade with AMS to be studied.
Asset Maintenance Schedules	Combination of manual systems, spread sheets and paper based records	Partial (minimum utility, as content & use constrained by spread sheet & paper based systems)	Upgrade with AMS to be studied.
Asset Operations Data	Combination of manual systems, spread sheets and paper based records	Partial (minimum utility, as content & use constrained by spread sheet & paper based systems)	Upgrade with AMS to be studied.
Contract Tracker	Part of Intech	Complete	Acceptable, useful, but not integrated with other systems other than rest of Intech. Upgrade with AMS to be studied.
Task Manager	In Outlook	Complete but has limitations	Acceptable, useful, but not integrated with other systems. Upgrade with AMS to be studied.

System	Process	Progress	Remarks
SCADA	iHistorian	Partial Completion	Greater network visibility is required.
ETap Modelling	System Update	Complete	Valuable connection planning tool
ICP Dbase	Review	Partial Completion	Updated details continuing
H&S and Human Resources database	Vault	H&S data complete	Staff training & competency. Stand alone system.

8.4 Possible AMP Improvements

AEL expects to improve the AMP in the future not simply by writing a better document but by improving the asset management processes and activities that fit behind the AMP document. In addition, AEL will focus on the results of the Commerce Commission’s Compliance Review of Electricity Distribution Businesses’ Asset Management Plans in order to achieve compliance in the partially and non compliant areas.

8.4.1 General Improvements

The first task required to be done towards improving the asset management processes and activities is analysing the existing process and determining areas requiring improvement or change.

The next task, undertaken in parallel to the first, is to examine the data processing, storage and presentation systems presently available, or in process of being made available, to ascertain what improvements and changes are necessary in this area.

Finally, the results of the first two tasks need to be evaluated and a strategy of improvement devised.

It is envisaged that once the data collection, entry, processing, storage, and permutation issues are properly understood, improvements will be undertaken to the databases and their interfaces.

These improvements include: the accurate and complete entry of appropriate data concerning the assets and their maintenance and operation; completion of all data fields associated with each asset item.

Only once this phase has been accomplished will it be feasible to consider implementing an “off the shelf” Asset Management System that uses the data and allows efficient, reliable, and complete management of the AEL assets.

The evolving requirements for AMPs places considerable pressure on Network Companies to move towards comprehensive, accurate and complete, software based, and database integrated, Asset Management System.

AEL's present asset data systems include several databases and software packages that are loosely interconnected either electronically or manually.

With these old legacy databases and software packages, individual data items often have to be entered separately into more than one package in order to satisfy the different database and software package requirements for the data.

The key to AEL's future Asset Management System is the developing GIS which must be expanded and integrated with other systems such as works planning, fault logging, and maintenance management. As discussed above, the data entry interfaces to the databases used by the GIS and other manual Asset Management System components are a separate issue that requires significant work before all necessary and sufficient data is able to be entered correctly and in a timely fashion.

While updating to a level of detail commensurate with the original field work has largely been achieved in 2009-10, and the connectivity of the 11 kV (and most of the LV) GIS data has also been achieved in 2009-10, the following two phases still largely remain:

- detailed data populating of the GIS and the other associated legacy databases, and

- the improvement to the software and manual entry interfaces between the human users and the various existing legacy software packages.

This latter phase requires an extensive review of AEL's database and asset management system requirements.

Both phases rely upon the selection and implementation of a modern, integrated database/Asset Management System solution.

This is now the critical development project for asset management for 2013/14 and beyond.

8.4.2 Assets Covered

Examples of the incompleteness of individual plant and equipment records in the present Asset Management Databases, are: the omission, in many cases, of the kVA size of transformers, plant serial numbers and other nameplate data (the nameplate details may not have been accessible or visible to the field staff or not understood); absence of maintenance data.

In addition, a considerable amount of work is yet to be done in the area of Condition Assessment, before the predominant condition of each class of asset may be identified for inclusion in the AMP. This would require a condition assessment survey of all items of each class and the resultant statistics analysed to determine a level of condition.

However, due to existing areas of urgency (e.g. need to assess the condition of LV distribution boxes) condition assessment work was initiated in 2008-09. This work employs NetCon staff using handheld data collection devises which allows the captured data to be down loaded later into an existing database for manual analysis by Asset Group staff and immediate action as required. This condition assessment programme has been extended to the ground mounted urban Distribution Substations in 2011 to supplement the existing routine distribution substation maintenance inspections undertaken by NetCon.

The information gathered as part of the distribution box and distribution transformer condition assessments will be used, beginning in 2013/14, to plan the civil maintenance of these assets. The work to be undertaken will include repairs to enclosures, removal and treatment of rust, repainting, and general repairs. Any electrical repairs not already completed during the condition assessment phase will also be undertaken while the assets are out of service for the civil maintenance work.

The initial field capture with site and equipment identification, further visits to complete equipment details and for condition assessment, the addition of maintenance data from NetCon, and subsequent installation records of new items entered into the GIS and AMS databases, should ultimately ensure an accurate record of assets.

Gathering of comments from manufacturers is yet to be done for the bulk of the assets.

8.4.3 Service Levels

The introduction in late 2009 of a centralized control room system with out-sourced operations to replace the area depot and fault operation and control system previously used for servicing the Network improved the efficiency and utilisation of the Operations Group. This change saw not only the improved collation of SAIDI and SAIFI data by the Operations Group but also an improvement of the analysis and reporting of this information to the AEL Board.

Further improvements and efficiencies in the gathering, processing and reporting of the SAIDI and SAIFI data will occur when the upgrading to the AMS occurs as outlined in the previous sections.

Installation of line capacitors was begun in 2008 to supplement the improvements gained by regulators in improving voltage regulation. This has however provided challenges in areas where ripple control plant is installed with the result that new installation is accompanied with an appropriately tuned choke to prevent the capacitor bank from sinking the ripple signal. This has however had a resultant increase in the cost per installation.

The continuing growth in irrigation loads on rural feeders and substations continues to exacerbate asset utilization performance.

8.4.4 Network Development Plans

The Timaru CBD network development planning was continued in 2011 but much work is yet to be done. Transpower GXP capacity & security agreements are still in discussion phases. Capital projects priorities and justifications have been reviewed and are presented in this AMP. The reassessment of changes to network constrains is still in process.

8.4.5 Lifecycle Asset Management Planning

The total Network asset maintenance and operations expenditure (OPEX) in the 2011-12 year was 4.094M. The progress of the maintenance programmes for 2011-12 were inhibited by the CAPEX budget taking priority over the allocation of available technical resources with the result that the OPEX budget of 5.05M was not exceeded. However, in 2012/13 additional NetCon resource was contracted to perform more detailed OPEX planning which is expected to bring the OPEX Budget back on track in the 2012/13 year and be further consolidated within the 2013-14 year.

Table 8.10a below details the annual expenditure on OPEX to 31st March 2012 by Asset Category.

- *Table 8.10a: OPEX Annual Spend to 31st March 2012 by Category*

Type:	Category:	Actual: ($k)	Budget: ($k)	% of Budget:	Comment:
1	LV Lines & Cable:	474	546	87%	under budget
2	Distribution Substations:	703	371	189%	over budget
3	Distribution Lines & Cables:	2,288	2,866	80%	under budget
4	Zone Substations:	448	995	45%	under budget
5	Sub-transmission Lines & Cables:	56	81	69%	under budget
6	SCADA & Radio:	148	191	78%	Under budget
7	*Unspecified:*	*0*	*1*	-%	
	Network Total:	**4,218**	**5,051**	**84%**	Under budget

The OPEX expenditure budget for the 2012-13 year was formulated with due regard to the 2011-12 actual expenditure. Table 8.10b below details the YTD expenditure on OPEX to 31st October 2012 by Asset Category.

- *Table 8.10b: OPEX YTD Spend to 31st December 2012 by Category*

Type:	Category:	Actual YTD: ($k)	Annual Budget: ($k)	% of 7/12 of annual Budget:	Comment:
1	LV Lines & Cable:	56	562	10%	under budget YTD
2	Distribution Substations:	695	715	97%	over budget YTD
3	Distribution Lines & Cables:	1,591	3,024	53%	under budget YTD
4	Zone Substations:	283	830	34%	under budget YTD
5	Subtransmission Lines & Cables:	29	68	43%	under budget YTD
6	SCADA & Radio:	137	153	90%	over budget YTD

Type:	Category:	Actual YTD: ($k)	Annual Budget: ($k)	% of 7/12 of annual Budget:	Comment:
7	Unspecified:	3	1	300%	
	Network Total:	**2,831**	**5,353**	**53%**	under budget YTD

The progress of the Network OPEX Actual verses Budget expenditure over the first nine months of the 2012-13 year to 31st December 2012 indicates that only 53% of the budget YTD had been spent. As for last year, the Opex under spend of the projected budget, is attributed to the large CAPEX spend absorbing more of the contractor's resource than originally planned.

Major maintenance is still required to be scheduled on a 5 year cycle. However, at present the achievement of this work is becoming delayed due to resourcing issues associated with the contractor.

Planned increases in technical staffing levels and the subcontracting of additional technical resources was planned to increase the levels of OPEX work completed in 2012/13. Unfortunately, in addition to the CAPEX drain on resources, technical staff turnover and difficulties in attracting replacements has resulted in decreases to the actual OPEX work through put.

Cable condition assessment for the Timaru 11 kV sub-transmission cables using VLF ac off-line PD mapping is normally assessed every two years.

However, the sub-transmission cable VLF PD tests in 2012 were postponed until 2013 due to the operational and resource constraints imposed by the urgent Grasmere St Sub 11 kV switchboard replacement project (CAPEX). This latter project has dominated work in the Timaru CBD from mid-2012 until the end of the 2012-13 financial year. As a consequence, the need to accelerate the maintenance programme for RMUs in the immediate vicinity of Grasmere St Sub as part of the 11 kV cable cutover work has meant that the OPEX RMU maintenance catch-up programme has been boosted.

Also, this same VLF ac off-line partial discharge mapping condition assessment was used in 2012 for a one-off testing of some selected 11 kV feeder cable sections in the Timaru CBD. These specially selected cables sections have cable joints of a type and installation date that have been noted to be susceptible to failure of recent years.

Nevertheless, the concentration of effort on the CAPEX budget and NetCons involvement in these projects has had the effect of seriously reducing the OPEX effort, as illustrated by the "under budget" spends presented in table 8.10b, above.

For all of the above and other reasons, it is proposed to maintain the OPEX budget for the 2013-14 and subsequent years at the levels planned in last year's AMP, but with some minor adjustments to individual category budgets.

8.4.6 Risk

Formal, analytical, risk analysis (as opposed to old fashioned experience and engineering judgement) is potentially very time consuming and therefore expensive if applied to each individual item of plant. A broad brush, or "type test", approach may provide a more affordable approach. More study needs to be devoted to this subject before an affordable and useful risk analysis system can be adopted for inclusion in the AMP. This subject is planned to be studied in more detail in 2013 and reported in the next AMP.

8.5 Asset Management Maturity

The 2014 disclosure year will be the first year in which electricity distribution businesses will report on their asset management maturity. The AMMAT is intended to assist interested persons to assess the maturity of AELs asset management strategy and delivery.

The AMMAT requires electricity distribution businesses to self–assess their asset management maturity. There is no 'pass' or 'fail' as such. Rather, scores are used to inform interested parties, including ourselves about our asset management practices. Our asset management practices include, but are not limited to, our internal policies, our communication strategy both internal and external, and the extent to which our asset management links to our overall company strategy.

Table 8.11 over page, 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 what does the score mean in regard to our asset maturity.

▪ ***Table 8.11: Extract of Schedule 13: Report on asset maturity***

Question No.	Question	Score	Maturity	User Guidance
3	To what extent has an asset management policy been documented, authorised and communicated?	2	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	Our Asset Management Policy is accessible by all staff on our intranet. The asset management plan (AMP) is reviewed and approved by senior management before being reviewed and approved by the Alpine Energy Limited (AEL) Board. Groups such as Engineering and the Drawing Office are given hard copies of the AMP. Hard copies are not distributed to all staff within AEL 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.
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	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	All our policy documents have a stated strategy or objective. Section 2, of the Asset Management Policy; describes how these documents are determined in line with this policy. While chapter 2 of the AMP, Background and Objectives links 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	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	Refer to chapter 6, Life Cycle Asset Management Planning and chapter 8.4.5 Lifecycle Asset Management Planning of our AMP.
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	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Refer to chapter 6, Life Cycle Asset Management Planning and Appendix C, Network CAPEX and summary forecasts, of our 2013 to 2023 AMP. This appendix lists the projects currently underway or about to start in the next twelve months.
27	How has the organisation communicated its plan(s) to all	2	The plan(s) are communicated to most of those responsible for delivery but	A copy of our AMP is available, at reception and on our website. Interested persons can request a hard copy

Question No.	Question	Score	Maturity	User Guidance
	relevant parties to a level of detail appropriate to the receiver's role in their delivery?		there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	through our office or access a copy form our website at http://www.alpineenergy.co.nz/
29	How are designated responsibilities for delivery of asset plan actions documented?	2	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Refer to chapter 7, Accountabilities for Asset Management of our 2013 AMP. Section 2.7 includes discussion of accountability at ownership level, governance, executive, management, operational, works and includes accountability of Netcon our subsidiary. Figure 2.2: Accountabilities for Asset Management at page 21 of our 2013 AMP shows the accountabilities at the ownership level. Detailed role descriptions are held by the Training and Compliance Manager for the Network Manager, the Asset Manager, Maintenance Manager, etc. NIMBUS, our financial system, records who has been designated to project manage specific jobs.
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)? (Note this is about resources and enabling support)?	2	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	Since 2005 we have recruited additional staff to ensure that our work plan can be completed. For example, in 2005 AEL had one network engineer and eight support staff. In 2012 AEL had grown to six network engineers and twelve support staff. A schedule of delegated authorities is held in the AMP. A Service Level Agreement is held between AEL and Netcon. The Board approves unplanned works and notes monthly variances through the Board papers circulated monthly to the Board and to senior management. Board meeting minutes are held by the Executive Assistant to the CEO. Field service training and training records as well as job descriptions are held by the Training and Compliance Manager.
33	What plan(s) and procedure(s) does the organisation have for identifying and responding to	1	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset	Refer to the Health & Safety Management System, (Reporting and Monitoring, pp. 16-19), the Emergency Preparedness Plan, the Network Policy Public Safety

Question No.	Question	Score	Maturity	User Guidance
	incidents and emergency situations and ensuring continuity of critical asset management activities?		management plan(s) and is in the process of determining an appropriate approach for achieving this.	Management System, and the Participant Outage Plan. The Participant Preparedness Plan chapter 4, General Control During an Emergency includes contingency planning including: site recovery order, critical facility by substation, customer contacts, and essential service contacts. Chapter 7, Emergency Response and Contingency Planning, of our 2013 AMP includes discussion of our business continuity planning, emergency preparedness plan, participant outage plan, specific contingency plans, and civil defence emergency management.The Training and Compliance Manager maintains our Risk Register and Incident Reporting through the Health and Safety Vault database (the Vault).
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	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The Asset Manager is responsible for managing asset delivery in accordance with our AMP policy. The team includes both permanent and contract staff for one-off projects. A role description for the Asset Manager is held with the Training and Compliance Manager who also holds Safety Management audit reports in the Vault database. Refer to section chapter 2.7 of our 2013 AMP for detailed discussion of our accountably for the management of our assets.
40	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	1	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	The Service Level Agreement held between AEL and Netcon includes assurance around resourcing and planning. Refer to section 2.1, Purpose of the AMP which states that a purpose of our AMP to ensure that we have made adequate provision for funding all phases of the network lifecycle. The Board is consistently apprised of our progress with the work programme as specified by our AMP. Budgets and variance analysis is carried out by senior management in particular the Corporate Services Manager and the Network Manager. Board meeting minutes are held by the Executive Assistant to the CEO.
42	To what degree does the	2	Top management communicates the	Progress on the AMP projects features regularly at

Question No.	Question	Score	Maturity	User Guidance
	organisation's top management communicate the importance of meeting its asset management requirements?		importance of meeting its asset management requirements but only to parts of the organisation.	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 is kept to those people that are considered to be relevant and who can directly influence outcomes. Our Training and Compliance Manager holds copies of all AEL job descriptions. Discussion of our progress with our AMP requirements and budgeting are held with the Board by senior management on a monthly basis. In particular the Corporate Services Manager and the Network Manager. Minutes are held by the Executive Assistant to the CEO. Engineers keep hard copies of standards manuals. Emergency recovery and disaster response arrangements are detailed in Safety Management System by the Health and Safety Manager.
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	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Planned maintenance on all AEL regulated assets are held and delegated to Netcon. The planning reports are held by Netcon's Technical Manager. Nimbus keeps track of job numbers and work orders between Netcon and AEL. New Connection data is held by the New Connection Team Leader. Our ICP database administered by IT Services.
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	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	Our training includes both safety and competency requirements, as described in training records and the competency matrix held by the Training and Compliance Manager. Training for fire wardens (Fire and Safety Training Ltd), driving, and first aid is provided by external certified persons. Our engineers attend Electrical Engineers Association forums to maintain their professional certifications. The Training and Compliance manager seeks feedback on courses, training, and forums attended through the group managers to identify good/bad

Question No.	Question	Score	Maturity	User Guidance
				courses.
49	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Refer to chapter 3, Competency Classifications and chapter 4, Network Authorisation, of the AEL Network Policy: Network Authorisation and Competency. The Training and Compliance Manager, keeps a training, licensing, and competency register (competency matrix). The Training and Compliance manager seeks feedback on courses, training, and forums attended through the group managers to identify good/bad courses.Competencies for professional engineers are found under the Chartered Professional Engineers Act 2002. Engineers must do a review of competence to practice in their field of expertise. Through the AMMAT process we have identified gaps in our formal record keeping for the training undertaken for some projects. Training for specialised projects such as substation refits relies on specific 'on the job' training. Gaps exist where this specific on the job training has not been formally recorded. We intend to review of process for recording training to try to capture this specific on the job training of our staff.
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	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Refer to chapter 3, Competency Classifications and chapter 4, Network Authorisation of the AEL Network Policy: Network Authorisation and Competency of the AMP. The Training and Compliance Manager maintains a competency matrix and training records for each AEL staff member. The Training and Compliance Manager also holds copies of the SMS audit reports.
53	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service	2	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect	Copies of our AMP and Asset Management Policy are available on our website at www.alpineenergy.co.nz and http://imgserv/ respectively. Our approval process of our AMP requires that the draft is reviewed and approved by senior management before being reviewed and approved by the Board. Groups such as Engineering and the

Question No.	Question	Score	Maturity	User Guidance
	providers?		to asset management information.	Drawing Office are given hard copies of the AMP. A soft copy of the AMP is accessible by all staff on the shared drive and to interested persons on our website. The Service Level Agreement is based around key elements of the AMP as it is devised under the watch of senior management. Job descriptions for key personnel show the need to communicate key AMP information.
59	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	1	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	We have completed BPM training, and the mapping of our business processes is near completion (target date 31 March 2013). Once complete we will have documented all of our processes. The BPM's will show the interactions between all of our processes. The mapping has been done the BPM project Manager holding discussions with key AEL staff to identify existing processes, in the first instance and then follow up meeting with all other staff identified in the process. Once the maps are completed copies will be made available to all AEL staff to review and provide comment to. These are mapped using Deloittes "New Industry Print" software. Information from this will be used to develop in house software where appropriate to improve and record key processes.
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	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The importance, relevance, and key information of our AMP is discussed regularly by senior management meetings and our Board at weekly and monthly meetings respectively. Our AMMAT scores and process was externally reviewed to get surety of the result and process taken. Board papers are circulated to all senior managers. In 2011 we had Deloittes carryout an external review of our existing information technologies. The review identified the need to replace some of our existing systems including our asset management system. It was determined that our BPM project could scope our overall companywide needs.
63	How does the organisation	1	The organisation is aware of the need	The Alpine Energy Limited IT Policy Statement gives a

Question No.	Question	Score	Maturity	User Guidance
	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?		for effective controls and is in the process of developing an appropriate control process(es).	broad outline of our overall IT policy. Data 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. Since the Deloittes review discussed above we have engaged an IT Manager and Business Analyst to complete the BPM project and are looking at a staged approach to the implementation of new systems.
64	How has the organisation ensured its asset management information system is relevant to its needs?	2	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations' needs.	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.
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	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	Refer to chapter 7, Risk Management of our 2013 AMP. Section 7.1 discusses risk from identification (also see subsection 7.1.2.) through to risk management improvements (see subsection 7.1.6.). Tables 7.1 to 7.5 give a pictorial overview of risk related asset management. Reporting is a function of the Training and Compliance Manager. The Health and Safety Management System details the process of the Hazard Register (p.40). Engineering staff have recently been to an Asset Health Indicator Forum run by the Electricity Engineers Association. Demand forecasts are completed by the Asset Manager for Transpower, both in summer and winter. Asset inspection for overhead lines is recorded by the Project Engineer. Larger failures may be investigated by the Senior Project Engineer, such as a recent outage on Clayton Rd. Asset condition reports are completed for dissolved gas analysis for all transformers above 3 MVA and partial discharge testing is completed every 6 months

Question No.	Question	Score	Maturity	User Guidance
				by contracted parties under the Asset Manager.
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	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	Refer to subsection 7.1.6. of the 2013 AMP, plans to improve the management of risk 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. See also section 3, Hazard Identification Assessment & Management, from the Health and Safety Management System, which includes a small section on training (p.30) and also Step 6 Monitor and Review (p.38) that discusses the involvement of all personnel in the risk management process and encourages ownership in the risk management process and subsequent development of hazard controls and other corrective measures", under Communicate and Consult. A Competency Matrix is held in our shared drive.The Training and Compliance Manager operates a Hazard Review and a Condition Review process, as well as a training needs analysis spread sheet and a competency matrix to determine training needs.
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	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	Acts, regulatory codes, standards etc. are found within the specific policy documents that each relate to. For the Health and Safety Management System see p. 10, Associated Documents and References for National Standards. Also on p.11, under the Health & Safety Roles & Responsibilities, Reference section are further national standards etc. The 2013 AMP includes a note under the purpose statement (p. 1-7) that the Plan must comply with Commerce Commission information disclosure requirements. References to various legislative requirements are included throughout the 2013 AMP. A position description is also held for the Training and Compliance Manager whose role it is to maintain a regulatory and codes information/database. See p. 19, Legislation, in the Public Safety Management System,

Question No.	Question	Score	Maturity	User Guidance
				which states [t]he Compliance and Training Manager is charged with ensuring that Management and employees are kept fully appraised of any updates to relevant legislation and statutory requirements.
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	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The maturity level of '1' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 2. Chapter 5, Network Development Planning, of our 2013 AMP shows the process for asset planning and decision making. There are not specific documents/ processes for acquisition, design, etc. however, individual projects that are either under way or planned can be found at section 5.9 and in Appendix C. At section 5.9 each main asset type is described in terms of its current state and proposed plans. Chapter 5 also provides our prioritisation of network development, including options to meet demand, (subsection 5.2.1) and choosing the best option (subsection 5.2.3). Section 5.1 outlines our planning criteria and includes at Table 5.1 a description of our approach to planning asset development. Chapter 5 includes discussion around our planning criteria and assumptions, prioritisation of network developments, demand forecasts, and analysis of network development options. We operate an 'open door' policy to new customer projects.
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	2	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The maturity level of '1' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 2. Refer to Chapter 4, Service Levels, and chapter 5, Network Development Planning, of our 2013 AMP. Chapter 6, Life Cycle Asset Management Planning, includes discussion around routine and preventative inspection and maintenance and performance programmes.

Question No.	Question	Score	Maturity	User Guidance
	conditions, are consistent with asset management strategy and control cost, risk and performance?			The chapter discusses that at AEL the overall management of maintenance is the responsibility of the Asset Manager who sets the policies and procedures within the bounds of the AMP. The Asset Manager is also responsible for the yearly updating and editing of the AMP with the assistance of various other individuals and departments within AEL The Asset Manager has a position description held with the Training and Compliance Manager. Commissioning check sheets have recently been completed by the Network Manager.
95	How does the organisation measure the performance and condition of its assets?	2	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Refer to subsection 6.8 Routine and Preventive Inspection, Maintenance and Performance, of our 2013 AMP. Also refer to p.21 Asset Inspection and Maintenance, of the Network Policy Public Safety Management System. For full details on maintenance refer to the following: • Network Policy – Plant and Transformer Maintenance • Evaluation of Performance as discussed at chapter 8 of our 2013 AMP. Our network performance, SAIDI, SAIFI and CAIDI measures, are discussed at chapter 8 of our 2013 AMP. Works implementation performance of new assets and existing assets is discussed at subsections 8.3.1. and 8.3.2 of our 2013 AMP respectively. In 2011 we implemented a new financial system which will make reporting and assessment more automated and efficient from next year on. AEL will continue dedicating resource to identify and implement areas for performance improvement (see subsection 8.3.2., p.8-9 of our 2013 AMP).
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	2	The organisation is in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	Refer to section 7.3, Asset Management Policy for Maintenance, and subsections 7.3.1, Deferred Maintenance 7.3.2, General Maintenance, and 7.3.3, Responsibilities, of our 2013 AMP. Also see chapter 6, AMP Life Cycle Asset Management Planning, particularly, section 6.8, Routine and Preventive Inspection, Maintenance and Performance

Question No.	Question	Score	Maturity	User Guidance
	is clear, unambiguous, understood and communicated?			Programmes and subsection 6.8.1, Maintenance Policies. For our emergency procedures refer to responsibilities outlined at chapters 2 and 3 of our Emergency Preparedness Plan, section 1 (p.8) of our Electricity Network Plant and Transformer Maintenance, and page 11 of the Health and Safety Management System. Further evidence can be seen under Responsibilities in our Participant Outage Plan, (refer to chapter 3.1) (Authorisation to Activate Participant Outage Plan). See also a Plant Fault form. Job descriptions are held by the Training and Compliance Manager.The Asset Manager maintains Powerco standards adopted for AEL.
105	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	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.
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	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non–compliance or incidents identified by investigations, compliance evaluation or audit.	Refer to section 6.8, Routine and Preventive Inspection, Maintenance and Performance Programmes, of our 2013 AMP. Particularly subsections 6.8.1, Maintenance Policies and 6.8.2.1., Zone Substations, Ground Mounted Substations and Switchgear. Also see our Health and Safety Management System, in particular p.16 Health and Safety Reporting and Performance Monitoring. This includes a performance monitoring criteria, measures (leading indicators) and a review of H&S performance. The purpose of section 2 is the development, implementation and improvement of the safety management system. The AEL Emergency Preparedness Plan, includes chapter 2, Responsibilities and Audit Meetings between AEL and Netcon happen every two weeks and discuss the physical progress of works. Commissioning check sheets for works on transformers greater than 300KVA have been completed by the

Question No.	Question	Score	Maturity	User Guidance
				Network Manager. OHL asset inspection is conducted by AEL project engineers on an ad hoc basis and during larger faults.
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	A Continual Improvement ethos is recognised as beneficial however, it has just been started, and or covers partially the asset drivers.	At chapter 8, Evaluation and Performance, of our 2013 AMP we discuss the external review of our 2013 AMP. We had our AMP externally reviewed to obtain an option as to the compliance, or other wise 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. Possible AMP improvements are discussed at section 8.4 including: general improvements, service levels, lifecycle asset management planning (i.e. OPEX actual vs. budget). Other recent actions include the hiring of a new IT Manager, Network Manager, and the acquisition of the Vault Health and Safety Data base. The AEL Asset Manager holds Mitton Electronet design reports.
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	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	Refer to subsection 8.4.1, General improvements, of our 2013 AMP. Use of Utility Consultants for evaluation, advice given from Sapere Group, PWC, Deloittes, teleconference meetings with the ENA. Attendance at EEA, EA, Downstream and Com Com conferences confirmation of which is held on various emails. A publication list is held by the Executive Assistant to the CEO.

APPENDIX A

SUMMARY OF ASSETS

2012 Disclosures				
Category	**Description**	**Replacement Cost ($)**	**%**	**Quantity**
Subtransmission		15,369,195	5.806392004	
	Lines	13,987,461	5.284380978	203 km
	Cables	1,291,072	0.487759452	40 km
	Isolation	90,662	0.034251573	
Zone Substations		18,035,641	6.813759712	
	Land	796,140	0.300777037	
	Buildings	2,473,741	0.934564885	
	Transformers	4,905,673	1.853334575	
	Indoor Equipment	4,436,979	1.676264722	
	Outdoor Equipment	990,930	0.37436756	
	Protection and Controls	535,105	0.20215954	
	Outdoor Structure	1,053,510	0.398009918	
	SCADA and Comms	1,355,752	0.512195178	
	Ripple Injection Plant	1,108,728	0.418870955	
	Other Items	379,083	0.143215341	
Distribution		119,612,327	45.18883774	
	Lines	82,807,101	31.28403857	2,878 km
	Cables	36,805,226	13.90479918	326 km
Distribution Switchgear		21,789,914	8.232102099	
	Disconnectors	2,015,588	0.761477361	
	Dropout Fuses	12,534,579	4.735490654	
	Sectionalisers	71,085	0.026855497	
	Reclosers	1,135,899	0.429136	
	Voltage Regulators	1,753,210	0.662352487	
	Ring Main Units	4,279,553	1.6167901	
Distribution Substations		8,167,927	3.085795061	
Distribution Transformers		41,649,556	15.73495872	
Low Voltage		31,130,517	11.7609273	
	Lines	11,587,096	4.377537117	381 km
	Cables	18,395,975	6.94989179	324 km
	Link pillar	1,147,446	0.433498389	
Service Connections		5,766,342	2.178490291	
	Overhead	3,172,990	1.198737069	
	Underground	2,593,352	0.979753222	
Other System Fixed Assets		3,172,990	1.198737069	
Exclude Land				
Total		264,694,409		

APPENDIX B

SUMMARY OF 11kV FEEDERS

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD (MW)
ABY0111	Albury	1	Cave	227	4642	393	207.78	1.10
ABY0111	Albury	2	Raincliff	85	2278	114	85.66	0.94
ABY0111	Fairlie	F309	Fairlie	325	11350	955	242.26	1.00
GXP	**Substation**	**Feeder**	**Description**	**Transformers**	**kVA**	**ICPs**	**km**	**MD (MW)**
BPD1101	Bells Pond	CB2	Ikawai	104	6565	146	67.36	2.96
BPD1101	Bells Pond	CB3	Waikakahi	80	3315	103	53.21	2.64
BPD1101	Bells Pond	CB4	Tawai	131	8120	356	70.87	3.05
BPD1101	Bells Pond	CB5	Ripple Plant	1	0	1	0.01	0.14
GXP	**Substation**	**Feeder**	**Description**	**Transformers**	**kVA**	**ICPs**	**km**	**MD (MW)**
STU0111	Studholme	1	Otaio	186	15133	304	114.01	4.13
STU0111	Studholme	2	Glenavy	33	2373	44	19.43	0.90
STU0111	Studholme	3	Waimate	89	12540	1855	33.32	4.79
STU0111	Studholme	7	Waihaorunga	145	5065	212	129.43	1.34
STU0111	Studholme	8	Mount Studholme	174	8468	287	88.10	2.72
STU0111	Studholme	9	Morven	170	7263	271	99.64	2.43
GXP	**Substation**	**Feeder**	**Description**	**Transformers**	**kVA**	**ICPs**	**km**	**MD (MW)**
TIM0111	Grasmere	2	White Street	5	1950	357	1.97	1.63
TIM0111	Grasmere	5	Nile Street	6	2650	578	2.57	1.69
TIM0111	Grasmere	6	Parkview Terrace	3	1950	9	3.29	2.04
TIM0111	Grasmere	7	Douglas Street	3	1400	241	1.51	0.54
TIM0111	Grasmere	10	Ashbury Park	4	1950	186	2.85	1.18
TIM0111	Grasmere	12	Selwyn Street	7	3100	543	2.28	1.80
TIM0111	Grasmere	15	Park Lane	6	2600	465	2.69	1.84
TIM0111	Grasmere	16	Evans St./North Mole	4	2650	9	3.67	1.90
TIM0111	Grasmere	17	June Street	3	1300	200	1.53	1.29
TIM0111	Grasmere	20	Hobbs Street	5	2600	408	2.00	1.65
TIM0111	Grasmere	21	Local Service No.2	1	75	1	0.01	0.00
TIM0111	Hunt	1	Harper Street	2	1000	232	1.22	2.00
TIM0111	Hunt	2	Wilson Street	5	1900	324	2.23	1.07
TIM0111	Hunt	4	Baker Street	4	1900	396	2.22	1.19
TIM0111	Hunt	5	Le Cren Street	8	4550	583	2.33	2.46
TIM0111	Hunt	7	Church Street - South Side Footway	4	2600	270	1.58	1.42
TIM0111	Hunt	10	Gibson Street	3	1200	174	2.26	1.84
TIM0111	Hunt	11	Rhodes Street	6	2350	589	2.60	1.54
TIM0111	Hunt	13	Clifton Terrace	4	1900	482	1.53	1.65
TIM0111	Hunt	14	Church Street - South Side Roadway	3	2150	62	1.93	0.89

TIM0111	Hunt	16	Arthur Street	5	3400	198	1.36	1.60
TIM0111	Pareora	CB3	Silverfern Farms No 3010					0.00
TIM0111	Pareora	CB4	St. Andrews	211	8945	376	128.5 5	0.00
TIM0111	Pareora	CB5	Silverfern Farms No 3020					
TIM0111	Pareora	CB6	Normanby	168	6135	523	75.17	2.00
TIM0111	Pareora	CB7	Holmestation	159	3929	281	115.6 5	1.50
TIM0111	Pleasant Point	1	Waitawa	124	60768	241	42.83	1.30
TIM0111	Pleasant Point	2	Sutherlands	67	1303	89	44.20	0.60
TIM0111	Pleasant Point	4	Totara Valley	148	7505	523	75.04	2.00
TIM0111	Pleasant Point	5	Pleasant Point Township	32	2775	305	16.54	1.50

GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD (MW)
TMK0331	Clandeboye	T600	Tie to Milk Powder					3.08
TMK0331	Clandeboye	T601	Fire Services					0.00
TMK0331	Clandeboye	T602	Whey Processing					3.46
TMK0331	Clandeboye	T603	Lactose Plane					0.97
TMK0331	Clandeboye	T604	Spare					2.50
TMK0331	Clandeboye	T605	Tie to Milford Clanderboye					0.33
TMK0331	Clandeboye	T606	Main Incoming - T1					0.00
TMK0331	Clandeboye	T607	Bus coupler					5.39
TMK0331	Clandeboye	T608	Milk Reception					0.68
TMK0331	Clandeboye	T609	Chilled Water					3.10
TMK0331	Clandeboye	T610	Effluent Plant					2.04
TMK0331	Clandeboye	T611	Milk Treatment					1.13
TMK0331	Clandeboye	T612	Rolleston Rd	85	7130	228	48.60	3.22
TMK0331	Clandeboye	T613	Tie to Powder Handling					98.76
TMK0331	Clandeboye	T650	Tie to Milk Powder					5.62
TMK0331	Clandeboye	T651	Milk Powder 3					6.10
TMK0331	Clandeboye	T652	Tie to WPC					2.28
TMK0331	Clandeboye	T653	chilled Water 3					1.47
TMK0331	Clandeboye	T654	Tie to Boiler House					0.00
TMK0331	Clandeboye	T656	Bus coupler					6.52
TMK0331	Clandeboye	T657	Main Incomer - T3					8.54
TMK0331	Clandeboye	T658	Milk Powder2					3.37
TMK0331	Clandeboye	T659	Tie to Energy Centre					0.00
TMK0331	Clandeboye	T660	Refigeration					1.74
TMK0331	Clandeboye	T661	Laboaratory					1.61
GXP	Substation	Feeder	Description	Transformers	kVA	ICPs	km	MD (MW)

TIM0111	Timaru	CB2682	Ripple Plant 1					0.45
TIM0111	Timaru	CB2692	North St. 1					3.78
TIM0111	Timaru	2702	Morgans Rd	21	5360	834	6.55	1.36
TIM0111	Timaru	2712	Mountain View Rd	33	6340	928	12.87	3.26
TIM0111	Timaru	2732	AEL T1	2	20140	2	17.79	3.18
TIM0111	Timaru	2742	Seadown	281	16485	775	96.75	3.29
TIM0111	Timaru	2762	AEL Yard	16	5180	138	6.83	3.10
TIM0111	Timaru	2832	Grants Rd	23	5750	1117	7.73	2.44
TIM0111	Timaru	2852	Levels	392	9478	809	156.66	1.22
TIM0111	Timaru	2862	Meadows Rd	16	9425	75	6.63	5.47
TIM0111	Timaru	CB2922	AEL T2					8.46
TIM0111	Timaru	2942	Old North Rd	15	7300	36	4.47	4.44
TIM0111	Timaru	2952	Highfield	62	10133	1456	22.20	2.72
TIM0111	Timaru	2972	Smithfield	12	2760	288	5.85	3.59
TIM0111	Timaru	CB2982	North St. 2					0.00
TIM0111	Timaru	2992	Ripple Plant No.2	1	0	3	0.02	0.47

TIM0111	North Street	CB3	Redruth 1					0.00
TIM0111	North Street	4	Rose St	4	2050	343	1.88	1.40
TIM0111	North Street	5	Craigie Ave	8	3500	701	3.55	1.36
TIM0111	North Street	8	Barnard St	5	2500	164	1.08	0.83
TIM0111	North Street	9	Port 1	1	500	2	0.86	0.00
TIM0111	North Street	10	Fraser St	5	2800	22	2.30	3.22
TIM0111	North Street	11	Hayes St	6	3800	75	1.87	3.12
TIM0111	North Street	12	High St	14	4405	261	6.58	1.45
TIM0111	North Street	13	Port 2	3	3400	13	1.81	0.00
TIM0111	North Street	16	Victoria St	5	2400	333	1.62	1.14
TIM0111	North Street	17	Safford St	5	3900	202	2.19	1.69
TIM0111	North Street	CB18	Redruth 2					0.00
TIM0111	North Street	CB35	NST-TIM 1					3.80
TIM0111	North Street	CB36	NST-TIM 2					0.00
GXP	**Substation**	**Feeder**	**Description**	**Transformers**	**kVA**	**ICPs**	**km**	**MD (MW)**
TKA0331	Balmoral	M216	Simons Pass	17	400	24	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	34	77.95	0.70
TKA0331	Tekapo	M200	Haldon-Lilybank	10	1875	63	5.66	0.94
TKA0331	Tekapo	M201	Balmoral	7	1775	6	6.02	0.35
TKA0331	Tekapo	M205	Godley	9	525	63	20.73	0.11
TKA0331	Tekapo	M206	Tekapo Township	21	3965	274	8.39	2.28

TKA0331	Tekapo	M207	Local Service	1	3050	2	0.06	0.30
TKA0331	Unwin Hut	M158	Village	5	2300	13	5.27	1.00
TKA0331	Unwin Hut	M159	Village	6	815	68	4.95	0.50
GXP	**Substation**	**Feeder**	**Description**	**Transformers**	**kVA**	**ICPs**	**km**	**MD (MW)**
TMK0331	Clandeboye Sub 1	T613	Rolleston Road	85	8030	228	48.60	0.00
TMK0331	Geraldine	1	Speechly	216	6823	393	124.59	1.00
TMK0331	Geraldine	2	Geraldine Township	75	9080	1334	25.43	2.50
TMK0331	Geraldine	3	Woodbury	284	7450	667	148.24	1.50
TMK0331	Rangitata	T552	Arundel	50	3865	80	30.74	2.00
TMK0331	Rangitata	T553	Rangitata Island	37	2825	54	21.72	1.50
TMK0331	Rangitata	T554	Mahan Road	20	1345	21	14.91	1.00
TMK0331	Rangitata	T555	Main South Road	88	6653	128	48.45	1.50
TMK0331	Rangitata	CB11	Belfield					
TMK0331	Rangitata	12	Orton	12	1020	13	6.49	
TMK0331	Rangitata	CB13	Ragitata ISL.					
TMK0331	Temuka	1	Temuka West	10	52425	411	5.28	5.32
TMK0331	Temuka	2	Milford	124	7270	261	56.20	2.41
TMK0331	Temuka	3	Winchester	207	9888	555	77.13	2.91
TMK0331	Temuka	7	Rangitata	107	8925	170	52.58	3.34
TMK0331	Temuka	8	Temuka East	69	12105	1770	22.70	5.28
TMK0331	Temuka	9	Waitohi	171	55336	268	107.65	2.54
GXP	**Substation**	**Feeder**	**Description**	**Transformers**	**kVA**	**ICPs**	**km**	**MD (MW)**
TWZ0331	Twizel	Z1	Urban No. 1	22	4230	607	6.99	1.19
TWZ0331	Twizel	Z2	Urban No. 2	29	5370	632	11.85	1.34
TWZ0331	Twizel	Z3	Industrial	1	50	1	0.21	0.00
TWZ0331	Twizel	Z4	Twizel Rural	42	2260	90	37.39	0.38
TWZ0331	Twizel	Z9	Local Service	1	3030	2	0.01	0.00
GXP	**Substation**	**Feeder**	**Description**	**Transformers**	**kVA**	**ICPs**	**km**	**MD (MW)**
Total		**132**		**5,535**	**582,548**	**30,747**	**3,229**	**339**

Note1: MD (MW) in Red are based on the previous AMP's engineering estimate. The remainder of the MD (MW) are actual figures taken from the SCADA system.

APPENDIC C

NETWORK CAPEX – SUMMARY FORECASTS

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.

High priority - Must Do Projects
Medium priority - Need To Do - Conditional upon an external party initiating a project - budget could possibly be deferred.

The projects are also categorised according to the relevant AMP Expenditure Category as follows:

- C = Customer Connection;
- G = System Growth;
- R = Asset Replacement & Renewal;
- S = Reliability, Safety & Environment;
- L = Asset Relocations.

APPENDIX C1 – CAPEX 12 month workplan for 2013/14

This appendix lists the projects currently underway or about to start in the next twelve months.

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2013/14	Project Details
R/G/S	Network - Various O/H new builds & upgrades	671	Cairns Rd Southburn replace 13GS conductor plan 1042 Waihao river crossing permanent repairs & pole shift. Improve Orari river crossing. Relocate ABS outside RGA sub to next S/O down road to SH1. Waihurunga irrigation line re-builds & upgrades.
G	BPD - Cooney's Rd 33 kV	3,500	New supply feeder to Oceania Dairy factory. 12 km 110 kV double circuit run at 33 kV.
G	RGA - Mahan Rd feeder extension	245	Ruddenklau Rd - 3.8 km new Iodine 11 kV
S	ABY - Reinsulate Cave 33 kV to 11 kV	60	Reinsulate by replacing 33 kV insulators with 11 kV insulators.
S	TMK - Rebuild to heavy up feeder to vinegar factory in 11 kV	50	Light conductor in high fault level. Public safety.
S	HNT - NST to Canada St (Hunt 2) replace Gopher 11 kV	45	Light conductor in high fault level. Public safety.
S	HNT - Archer St (Hunt 11) replace 25 Cu 11 kV	25	Light conductor in high fault level. Public safety.
S	TMK - St Leonards St - replace 16 Cu 11 kV	15	Light conductor in high fault level. Public safety.
R	Network - Miscellaneous ABS replacements	140	Replacement of known ABS which are failing and replacement with load breaks to improve network switching.
G	STU - McNamara's Rd rebuild	250	SH 1 to WTE Cemetery, rebuild Ferret to Iodine 11 kV
G	PAR - Sub transmission lines reconductor to Iodine	822	Pareora 33 kV 1 & 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 criterium. Some 2010/11 work not completed & budget carried forward.

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2013/14	Project Details
C	Network - New subdivisions & extensions for new services	1,500	New connections and extensions as well as subdivisions.
C	Network - Profile & Smart Meters	500	Installation of profile and smart meters for network benefits.
C	Network - Transformers distribution for subdivisions, extensions & replacements	600	Transformer purchases.
G	Network - Voltage Support (line regulator and shunt capacitor bank installations)	120	This budget item is related to load growth. 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.
R	Network - Distribution Sub refurbishment	100	General budget for refurbishment projects at distribution substations.
R	Network - Two pole distribution sub refurbish.	160	Safety & 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.
R	Network - New Ring Main Units & Replacements	400	General budget for the replacement of existing as well as new ring main units.
S	Network - Reclosers New	160	New installations as required to improve supply reliability and general network growth.
R	Network - Reclosers Replacements	100	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.

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2013/14	Project Details
			Cooper reclosers are also being changed out, retro fitted with SEL relays and re-deployed on the network.
S	Network - Deep driven earths	150	Results from earth testing program shows large number of sites outside of regulations. Budget based on 85 NB sites identified @ $2,500 per site.
S	HLB - 11/22 kV Substation Upgrade final stage	150	Completion of substation upgrade that was started in 2011 due to transformer failure.
G	Network - Underground Cable Upgrades	320	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.
S	Network - 11 kV & 33 kV Overhead Lines in urban areas conversion to underground for Network reasons	200	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.
S	GRM - Wilson St U/G	807	585 meters of undergrounding as agreed with TDC.
S	GRM - Chalmers St U/G 11 kV	360	215 meters of undergrounding replacing light overhead conductor
S	GRM - Guiness St (GRM 7) U/G 11 kV	538	390 meters of undergrounding replacing light overhead conductor
R	Network - Zone Substation Protection replacement	200	Replacement of old electromechanical or electronic relays that are at end of life, and upgrading of some existing protection.
R	Network - 33 kV CB & recloser replacement	75	Replacing old oil CB's with vacuum CB's i.e. Unwin Hut, Balmoral, Albury, Haldon, Fairlie.
R	ALB - Ripple Plant replacement & LS rework	100	Replace old rotary plant which is giving problems. Relays (in stock) must also be replaced.
R	ALB - Ripple Relay Changeout / Now Smart Meters	200	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.

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2013/14	Project Details
R	CD1 - & CD2 SCADA & protection upgrade	88	This project is to complete outstanding work from last year as well as the carry-over from last year of the protection inter-trip as part of the Canal Rd corner tee-off as proposed to Fonterra. The budget is sufficient if Transpower agrees to the installation of fibre inter-trip from their circuit breakers.
S	TIM - Ripple Plant upgrade (x2)	400	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.
G	Network - New Equipment	150	Budget used last year mainly for procurement of replacement vehicles and reduced for this year.
C	Network - QOS Investigations	50	Investigations into power quality as and when required.
S	Network - Mobile 33/11 kV substation, 5/8 MVA Dyn11	1,400	Mobile substation for reducing SAIDI minutes during planned maintenance.
S	Network - Diesel Generators / Step-up Tx	980	Standby diesel generators to assist in reducing SAIDI minutes during emergency repairs and planned maintenance.
R	Network - Ex-Pareora T1 & T2 refurbishment	190	Refurbishment of Pareora transformer for deployment elsewhere on the network.
G	TIM - Upgrade 33 kV Switchgear	200	This is a preliminary budget based on existing feeders and using the Portacom design at Pareora.
R	Network - RTU replacement	100	Replacing existing RTUs at end of life.
R	HNT - 11 kV protection/control replacement (17 CBs)	100	Upgrading of protection systems to standardise and to comply with current protection philosophy.
R	TIM - Replace NETs (x 2) for 11/33 kV	250	Current NETs at end of life. Also forms part of protection upgrade.
R	FLE - Substation upgrade	200	Preparation of FLE substation to connect mobile substation. This will then allow major upgrade project without disconnecting customers.
R	Network – New SCADA Master Station	450	Replacing the existing maters station at end of life.
S	BDC - Comms Hut replacement	50	Equipment at end of life.

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2013/14	Project Details
S	WDK - Communications room upgrade	100	General budget to cover for upgrading to new SCADA master station.
S	Network - SCADA pole top equipment automation (e.g. reclosers)	250	Budget to establish communications network and automate pole mounted reclosers.
S	Network - Upgrade Security Lock/Key System for all Network Plant and Equipment, starting with Zone Substations.	100	Completion of project to change-out all old locks with new Abloy locks.
G	BPD - 33 kV CB for Oceania Dairies	700	Install 110 kV CB and related protection and metering for supply to Oceania Dairy factory.
G	BPD - Cooneys Road Oceania Dairies Substation	2,350	Total budget $3.25m, but $900k capital contribution deducted. One 9/15 MVA 33/11 kV transformer, 33 kV CB, RPS switchboard with 2 incomers, 4 feeder panels and 2 bus couplers.
G	BPD - Cooneys Road Oceania Dairies Plant Reticulation	390	The scope of this works is currently unknown. Budget based on AEL procuring transformers and RMU's, Oceania paying for cables and civil works. Budget based on 5.86 MVA total load in 2014 through 6X1 MVA Tx and RMU combinations, @ $65k per combination.
	Total	**21,062**	

APPENDIX C2 – CAPEX 4 year forecast

This appendix lists the projects for the four years 2014/15 to 2017/18. The AMP Categories are similar to Appendix C1 above.

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2014/15	Budget (000's) 2015/16	Budget (000's) 2016/17	Budget (000's) 2017/18
R/G/S	Network - Various O/H new builds & upgrades	1,750	1,450	1,400	1,400
G	PAR - Sub transmission lines reconductor to Iodine	502	502	-	-
C	Network - New subdivisions & extensions for new services	1,500	1,500	1,500	1,300
C	Network - Transformers distribution for subdivisions, extensions & replacements	600	600	600	500
G	Network - Voltage Support (line regulator and shunt capacitor bank installations)	80	80	80	180
R	Network - Distribution Sub refurbishment	120	140	160	160
R	Network - Two pole distribution sub refurbish.	160	160	160	160
R	Network - New Ring Main Units & Replacements	400	350	350	350
S	Network - Reclosers New	120	60	60	120
R	Network - Reclosers Replacements	58	58	58	122
S	Network - Deep driven earths	150	100	50	30
G	Network - Underground Cable Upgrades	500	500	500	500
S	Network - 11 kV & 33 kV Overhead Lines in urban areas conversion to underground for Network reasons	200	510	180	250
R	Network - Zone Substation Protection replacement	50	50	50	200
R	Network - 33 kV CB & recloser replacement	-	75	-	-
R	ALB - Ripple Relay Changeout / Now Smart Meters	200	-	-	-
S	TIM - Ripple Plant upgrade (x2)	400	-	-	-
G	Network - New Equipment	150	150	150	150
C	Network - QOS Investigations	50	50	50	50
G	TIM - Upgrade 33 kV Switchgear	2,000	-	-	-

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2014/15	Budget (000's) 2015/16	Budget (000's) 2016/17	Budget (000's) 2017/18
R	Network - RTU replacement	100	50	50	50
R	HNT - 11 kV protection/control replacement (17 CBs)	665	-	-	-
S	Network - SCADA pole top equipment automation (e.g. reclosers)	250	200	200	100
S	Network - Upgrade Security Lock/Key System for all Network Plant and Equipment, starting with Zone Substations.	50	50	-	-
	Totals	**10,055**	**6,635**	**5,598**	**5,622**

APPENDIX C3 – CAPEX 2018-2023 forecast

This appendix lists the projects for the five years 2018/19 to 2022/23. The AMP Categories are similar to Appendic C1 above.

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2018/19	Budget (000's) 2019/20	Budget (000's) 2020/21	Budget (000's) 2021/22	Budget (000's) 2022/23
R/G/S	Network - Various O/H new builds & upgrades	1,400	1,450	1,450	1,400	1,200
C	Network - New subdivisions & extensions for new services	1,300	1,200	1,200	1,000	1,000
C	Network - Transformers distribution for subdivisions, extensions & replacements	500	600	600	550	550
G	Network - Voltage Support (line regulator and shunt capacitor bank installations)	180	120	180	120	120
R	Network - Distribution Sub refurbishment	160	160	160	160	160
R	Network - Two pole distribution sub refurbish.	160	160	160	160	160
R	Network - New Ring Main Units & Replacements	300	300	300	300	300
S	Network - Reclosers New	120	60	60	60	60
R	Network - Reclosers Replacements	122	122	122	122	60
S	Network - Deep driven earths	30	25	25	25	25
G	Network - Underground Cable Upgrades	500	500	500	500	500
S	Network - 11 kV & 33 kV Overhead Lines in urban areas conversion to underground for Network reasons	1,000	2,000	-	-	-
R	Network - Zone Substation Protection replacement	50	50	50	50	50
R	Network - 33 kV CB & recloser replacement	-	-	-	150	
G	Network - New Equipment	150	150	150	150	150
C	Network - QOS Investigations	50	50	50	50	50
R	Network - RTU replacement	50	50	50	50	50
S	Network - SCADA pole top equipment automation (e.g. reclosers)	100	100	100	100	100
	Totals	**6,172**	**7,097**	**5,157**	**4,947**	**4,535**

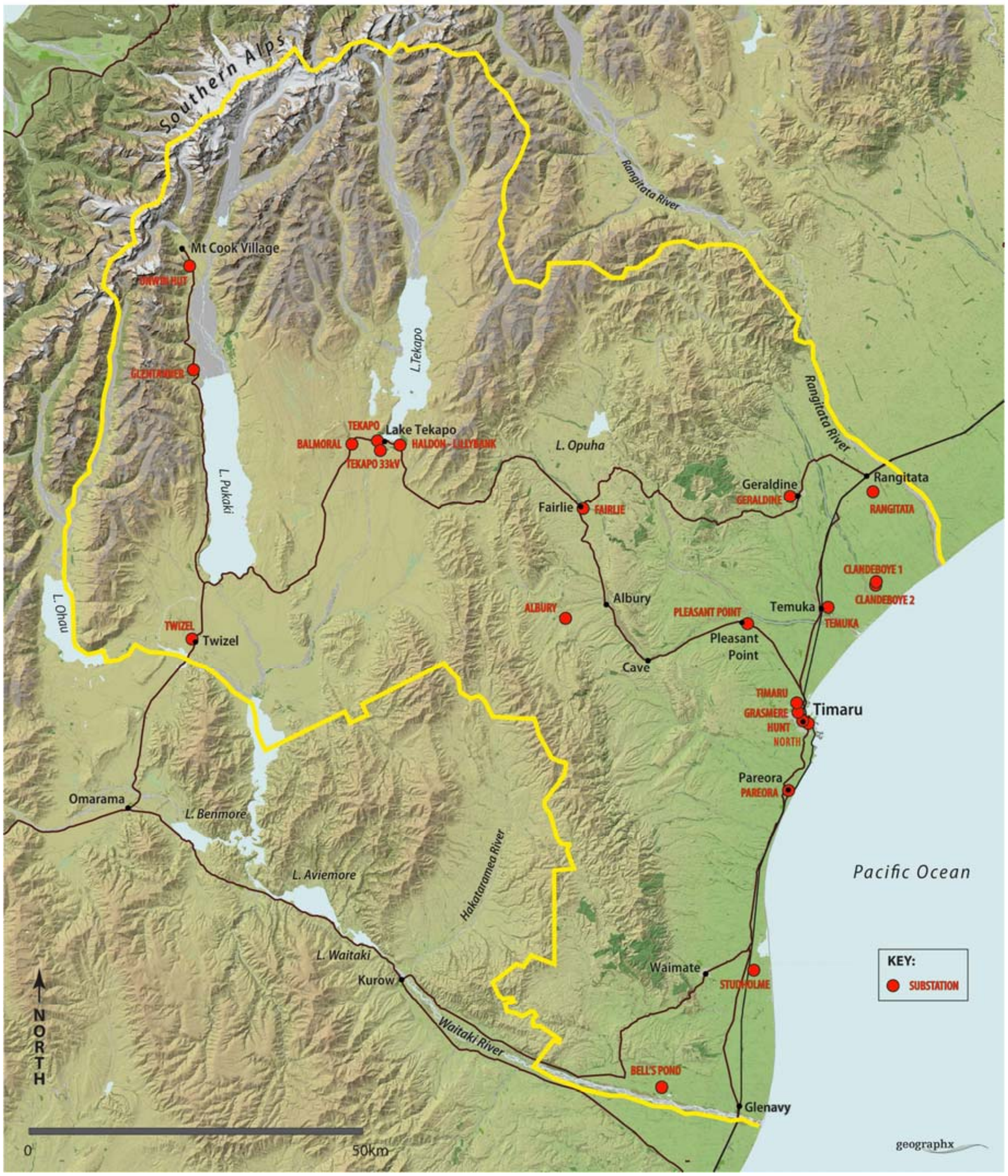
APPENDIX C.4 – CAPEX 10 year forecast

This appendix lists all the projects for the full 10 year AMP period from 2013/14 to 2022/23.

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2013/14	Budget (000's) 2014/15	Budget (000's) 2015/16	Budget (000's) 2016/17	Budget (000's) 2017/18	Budget (000's) 2018/19	Budget (000's) 2019/20	Budget (000's) 2020/21	Budget (000's) 2021/22	Budget (000's) 2022/23
R/G/S	Network - Various O/H new builds & upgrades	671	1,750	1,450	1,400	1,400	1,400	1,450	1,450	1,400	1,200
G	BPD - Cooney's Rd 33 kV	3,500	-	-	-	-	-	-	-	-	-
G	RGA - Mahan Rd feeder extension	245	-	-	-	-	-	-	-	-	-
S	ABY - Reinsulate Cave 33 kV to 11 kV	60	-	-	-	-	-	-	-	-	-
S	TMK - Springfield Rd replace 7/12 Cu 11 kV	-	-	-	-	-	-	-	-	-	-
S	TMK - Rebuild to heavy up feeder to vinegar factory in 11 kV	50	-	-	-	-	-	-	-	-	-
S	HNT - NST to Canada St (Hunt 2) replace Gopher 11 kV	45	-	-	-	-	-	-	-	-	-
S	HNT - Archer St (Hunt 11) replace 25 Cu 11 kV	25	-	-	-	-	-	-	-	-	-
S	TMK - St Leonards St - replace 16 Cu 11 kV	15	-	-	-	-	-	-	-	-	-
R	Network - Miscellaneous ABS replacements	140	-	-	-	-	-	-	-	-	-
G	STU - McNamara's Rd rebuild	250	-	-	-	-	-	-	-	-	-
G	PAR - Sub transmission lines reconductor to Iodine	822	502	502	-	-	-	-	-	-	-
C	Network - New subdivisions & extensions for new services	1,500	1,500	1,500	1,500	1,300	1,300	1,200	1,200	1,000	1,000
C	Network - Profile & Smart Meters	500	-	-	-	-	-	-	-	-	-
C	Network - Transformers distribution for subdivisions, extensions & replacements	600	600	600	600	500	500	600	600	550	550
G	Network - Voltage Support (line regulator and shunt capacitor bank installations)	120	80	80	80	180	180	120	180	120	120
R	Network - Distribution Sub refurbishment	100	120	140	160	160	160	160	160	160	160
R	Network - Two pole distribution sub refurbish.	160	160	160	160	160	160	160	160	160	160
R	Network - New Ring Main Units & Replacements	400	400	350	350	350	300	300	300	300	300
S	Network - Reclosers New	160	120	60	60	120	120	60	60	60	60
R	Network - Reclosers Replacements	100	58	58	58	122	122	122	122	122	60
S	Network - Deep driven earths	150	150	100	50	30	30	25	25	25	25
S	HLB - 11/22 kV Substation Upgrade final stage	150	-	-	-	-	-	-	-	-	-
G	Network - Underground Cable Upgrades	320	500	500	500	500	500	500	500	500	500
S	Network - 11 kV & 33 kV Overhead Lines in urban areas conversion to underground for Network reasons	200	200	510	180	250	1,000	2,000	-	-	-
S	GRM - Wilson St U/G	807	-	-	-	-	-	-	-	-	-
S	GRM - Chalmers St U/G 11 kV	360	-	-	-	-	-	-	-	-	-
S	GRM - Guiness St (GRM 7) U/G 11 kV	538	-	-	-	-	-	-	-	-	-
R	Network - Zone Substation Protection replacement	200	50	50	50	200	50	50	50	50	50
R	Network - 33 kV CB & recloser replacement	75	-	75	-	-	-	-	-	150	-
R	ALB - Ripple Plant replacement & LS rework	100	-	-	-	-	-	-	-	-	-
R	ALB - Ripple Relay Changeout / Now Smart Meters	200	200	-	-	-	-	-	-	-	-
G	BPD - Ripple Plant Enhancement to suit T1 addition	-	100	-	-	-	-	-	-	-	-
R	CD1 - & CD2 SCADA & protection upgrade	88		-	-	-	-	-	-	-	-
G	STU - Ripple Plant Cell upgrade		100	50	-	-	-	-	-	-	-
S	TIM - Ripple Plant upgrade (x2)	400	400	-	-	-	-	-	-	-	-
G	Network - New Equipment	150	150	150	150	150	150	150	150	150	150
C	Network - QOS Investigations	50	50	50	50	50	50	50	50	50	50
S	Network - Mobile 33/11 kV substation, 5/8 MVA Dyn11	1,400	-	-	-	-	-	-	-	-	-
S	Network - Diesel Generators / Step-up Tx	980	-	-	-	-	-	-	-	-	-
R	Network - Ex-Pareora T1 & T2 refurbishment	190	-	-	-	-	-	-	-	-	-

Expenditure Cat.	AEL Works Programme Projects	Budget (000's) 2013/14	Budget (000's) 2014/15	Budget (000's) 2015/16	Budget (000's) 2016/17	Budget (000's) 2017/18	Budget (000's) 2018/19	Budget (000's) 2019/20	Budget (000's) 2020/21	Budget (000's) 2021/22	Budget (000's) 2022/23
G	GLD - Zone Substation upgrade	-	-	100	1,800	-	-	-	-	-	-
G	TIM - Upgrade 33 kV Switchgear	200	2,000	-	-	-	-	-	-	-	-
G	TIM - Cable two 33 kV circuits to Pages/Morgans Road	-	-	-	3,100	-	-	-	-	-	-
R	Network - RTU replacement	100	100	50	50	50	50	50	50	50	50
R	HNT - 11 kV protection/control replacement (17 CBs)	100	665	-	-	-	-	-	-	-	-
R	TIM - Replace NETs (x 2) for 11/33 kV	250	-	-	-	-	-	-	-	-	-
R	FLE - Substation upgrade	200	-	-	-	-	-	-	-	-	-
R	TEK - Change-out oil CBs for LMVP	-	100	-	-	-	-	-	-	-	-
R	Network - New SCADA Master Station	450	-	-	-	-	-	-	-	-	-
R	UHT - Sub (33/11 kV), change-out oil CBs for LMVP	-	50	-	-	-	-	-	-	-	-
S	KIM - Comms Hut replacement	50	-	-	-	-	-	-	-	-	-
S	WDK - Communications room upgrade	100	-	-	-	-	-	-	-	-	-
S	Network - SCADA pole top equipment automation (e.g. reclosers)	250	250	200	200	100	100	100	100	100	100
S	Network - Upgrade Security Lock/Key System for all Network Plant and Equipment, starting with Zone Substations.	100	50	50	-	-	-	-	-	-	-
G	BPD - 33 kV CB for Oceania Dairies	700	-	-	-	-	-	-	-	-	-
G	BPD - Cooneys Road Oceania Dairies Substation	2,350	-	-	-	-	-	-	-	-	-
G	BPD - Cooneys Road Oceania Dairies Plant Reticulation	390	-	-	-	-	-	-	-	-	-
G	SDW - 33/11 kV New Zone Sub	-	-	2,000	2,000	-	-	-	-	-	-
G	SDW - 33 kV cable (say 4x4km + 1x2km) from TIM run at 11 kV initially	-	2,000	2,000	-	-	-	-	-	-	-
G	SDW - 33/11 Zone Sub mesh existing network to station	-	500	-	-	-	-	-	-	-	-
	Totals	**21,062**	**12,905**	**10,785**	**12,498**	**5,622**	**6,172**	**7,097**	**5,157**	**4,947**	**4,535**

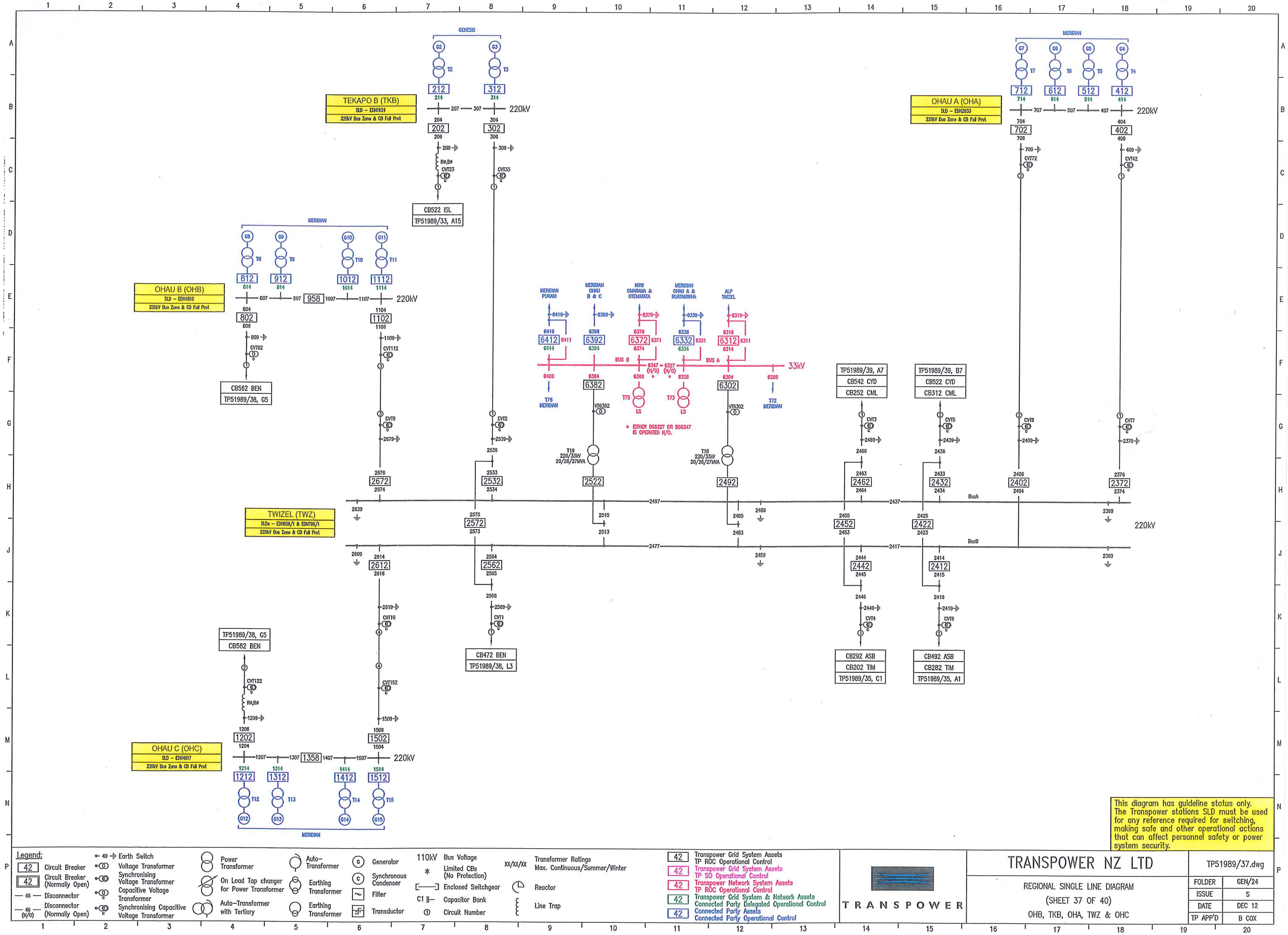
APPENDIX D – AREA OF SUPPLY

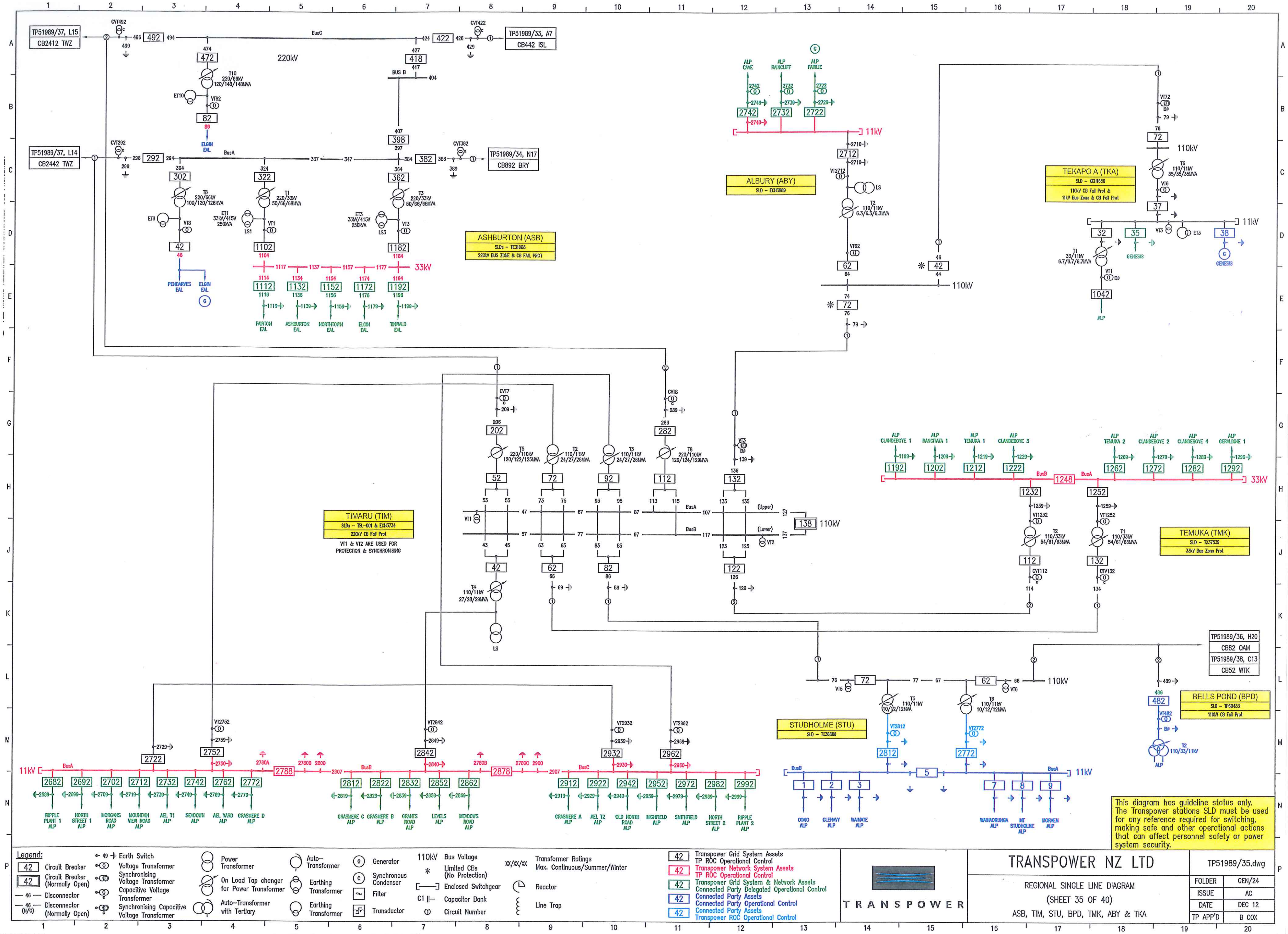


APPENDIC E

TRANSPOWER INTERCONNECTIONS

The following two single line diagrams show the Transpower network with the GXP supply points to AEL.

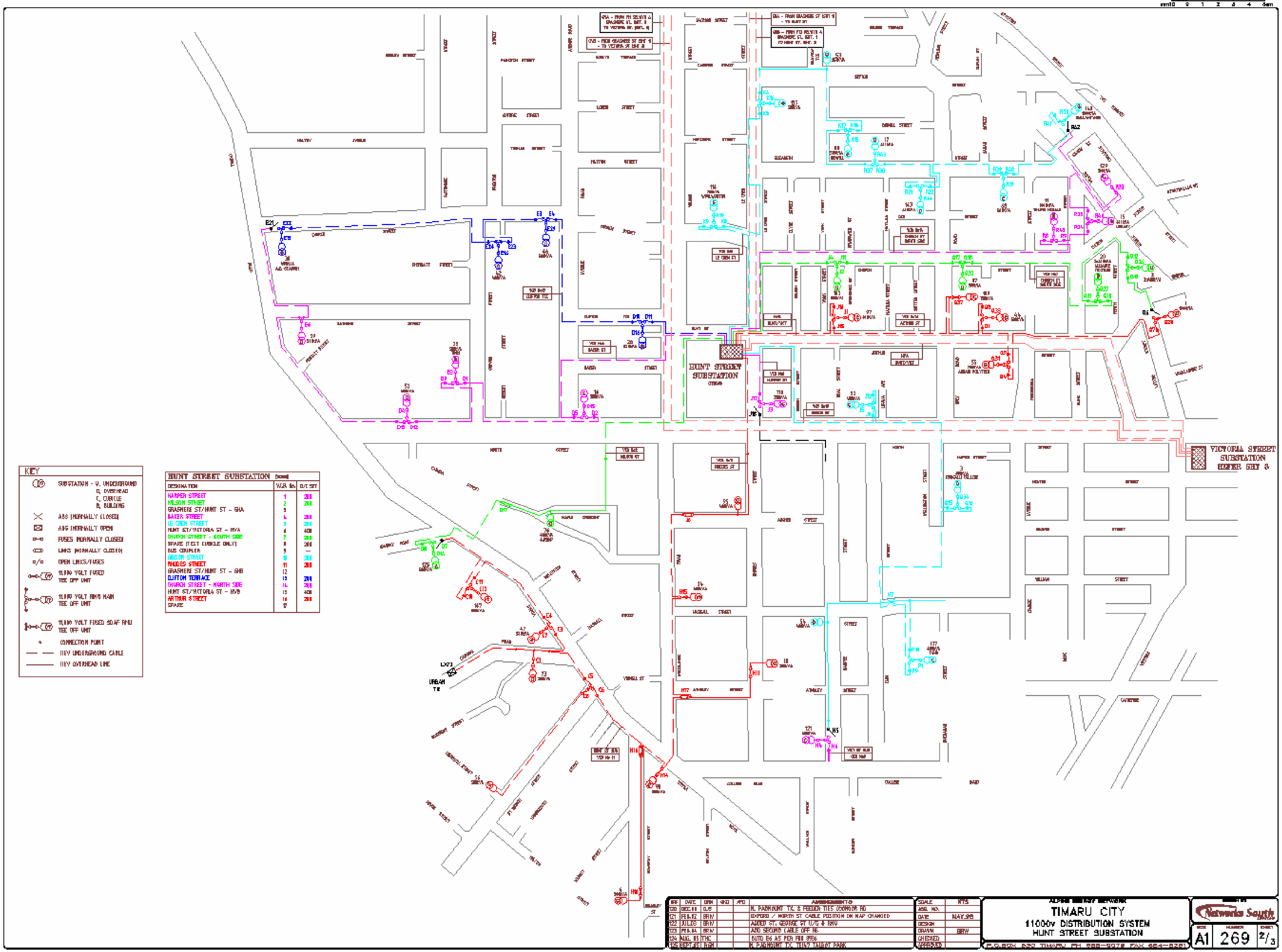

TEKAPO B (TKB)
OHAU A (OHA)
OHAU B (OHB)
OHAU C (OHC)
TWIZEL (TWZ)
GENESIS
MERIDIAN
220kV
33kV
BUS A
BUS B
CB522 ISL
TP51989/33, A15
CB562 BEN
TP51989/38, G5
TP51989/39, A7
CB542 CYD
CB252 CML
TP51989/39, B7
CB522 CYD
CB312 CML
TP51989/38, G5
CB582 BEN
CB472 BEN
TP51989/38, L3
CB292 ASB
CB202 TIM
TP51989/35, C1
CB492 ASB
CB282 TIM
TP51989/35, A1
This diagram has guideline status only. The Transpower stations SLD must be used for any reference required for switching, making safe and other operational actions that can affect personnel safety or power system security.
Legend:
Circuit Breaker
Circuit Breaker (Normally Open)
Disconnector
Disconnector (Normally Open)
Earth Switch
Voltage Transformer
Synchronising Voltage Transformer
Capacitive Voltage Transformer
Synchronising Capacitive Voltage Transformer
Power Transformer
On Load Tap changer for Power Transformer
Auto-Transformer with Tertiary
Auto-Transformer
Earthing Transformer
Generator
Synchronous Condenser
Filter
Transducer
Bus Voltage
Limited CBs (No Protection)
Enclosed Switchgear
Capacitor Bank
Circuit Number
Transformer Ratings Max. Continuous/Summer/Winter
Reactor
Line Trap
Transpower Grid System Assets TP ROC Operational Control
Transpower Grid System Assets TP SO Operational Control
Transpower Network System Assets TP ROC Operational Control
Transpower Grid System & Network Assets Connected Party Delegated Operational Control
Connected Party Assets Connected Party Operational Control
TRANSPOWER
TRANSPOWER NZ LTD
REGIONAL SINGLE LINE DIAGRAM
(SHEET 37 OF 40)
OHB, TKB, OHA, TWZ & OHC
TP51989/37.dwg
FOLDER GEN/24
ISSUE S
DATE DEC 12
TP APP'D B COX



220kV
110kV
33kV
11kV
ASHBURTON (ASB)
ALBURY (ABY)
TEKAPO A (TKA)
TIMARU (TIM)
VT1 & VT2 ARE USED FOR PROTECTION & SYNCHRONISING
TEMUKA (TMK)
STUDHOLME (STU)
BELLS POND (BPD)
TP51989/37, L15
CB2412 TWZ
TP51989/33, A7
CB442 ISL
TP51989/37, L14
CB2442 TWZ
TP51989/34, N17
CB892 BRY
TP51989/36, H20
CB82 OAM
TP51989/38, C13
CB52 WTK
This diagram has guideline status only. The Transpower stations SLD must be used for any reference required for switching, making safe and other operational actions that can affect personnel safety or power system security.
Legend:
Circuit Breaker
Circuit Breaker (Normally Open)
Disconnector
Disconnector (Normally Open)
Earth Switch
Voltage Transformer
Synchronising Voltage Transformer
Capacitive Voltage Transformer
Synchronising Capacitive Voltage Transformer
Power Transformer
On Load Tap changer for Power Transformer
Auto-Transformer with Tertiary
Auto-Transformer
Earthing Transformer
Generator
Synchronous Condenser
Filter
Transducer
Bus Voltage
Limited CBs (No Protection)
Enclosed Switchgear
Capacitor Bank
Circuit Number
Transformer Ratings Max. Continuous/Summer/Winter
Reactor
Line Trap
Transpower Grid System Assets TP ROC Operational Control
Transpower Network System Assets TP ROC Operational Control
Transpower Grid System & Network Assets Connected Party Delegated Operational Control
Connected Party Assets Connected Party Operational Control
Connected Party Assets Transpower ROC Operational Control
TRANSPOWER
TRANSPOWER NZ LTD
REGIONAL SINGLE LINE DIAGRAM (SHEET 35 OF 40)
ASB, TIM, STU, BPD, TMK, ABY & TKA
TP51989/35.dwg
FOLDER GEN/24
ISSUE AC
DATE DEC 12
TP APP'D B COX

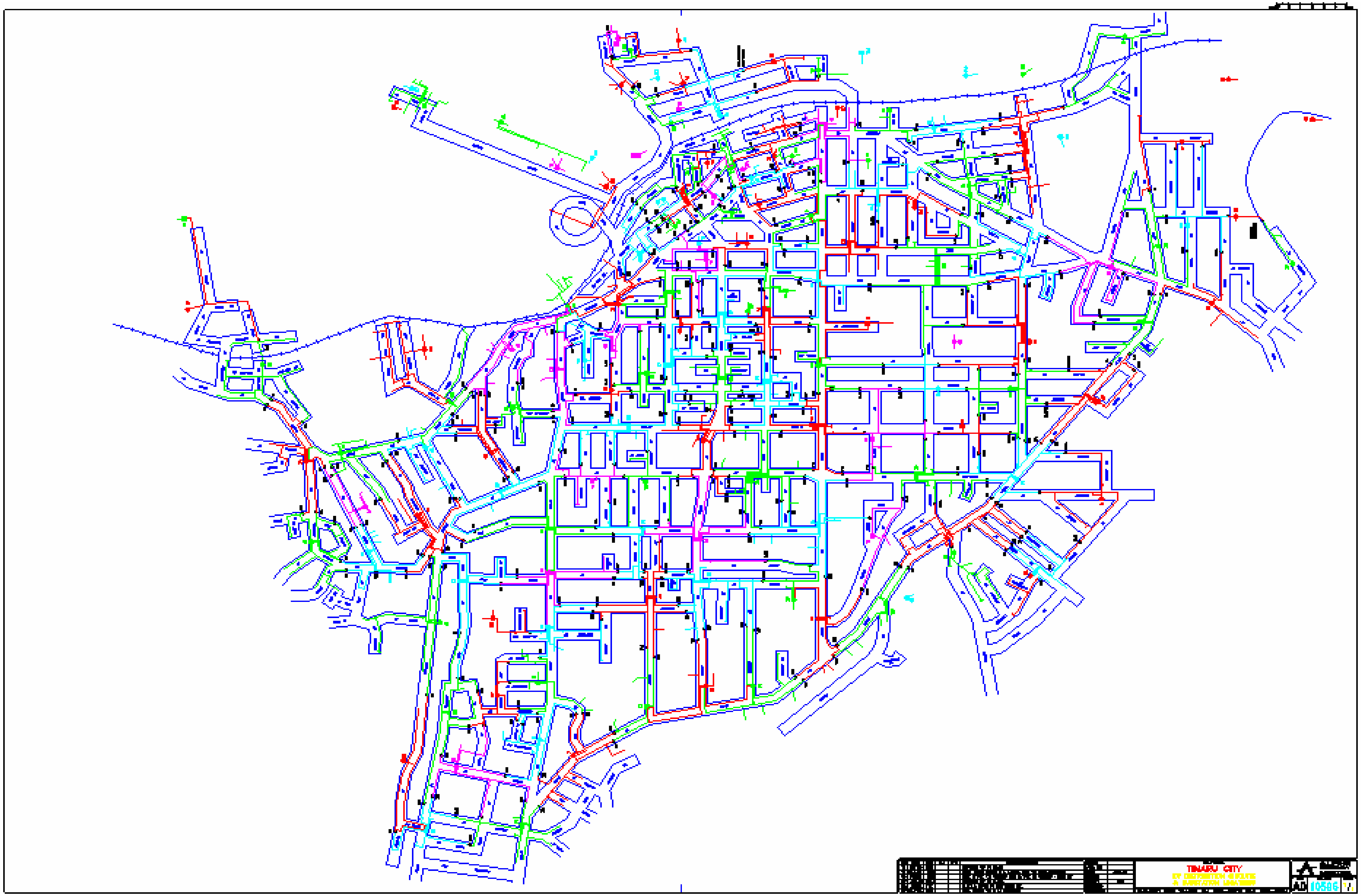
APPENDIX F

TIMARU 11kV SYSTEM


HUNT STREET SUBSTATION
VICTORIA STREET SUBSTATION REFER SHT 3
KEY
TIMARU CITY
11000v DISTRIBUTION SYSTEM
HUNT STREET SUBSTATION
SCALE NTS
DATE MAY.98
DRAWN BRW
A1 269 2/3

APPENDIC G

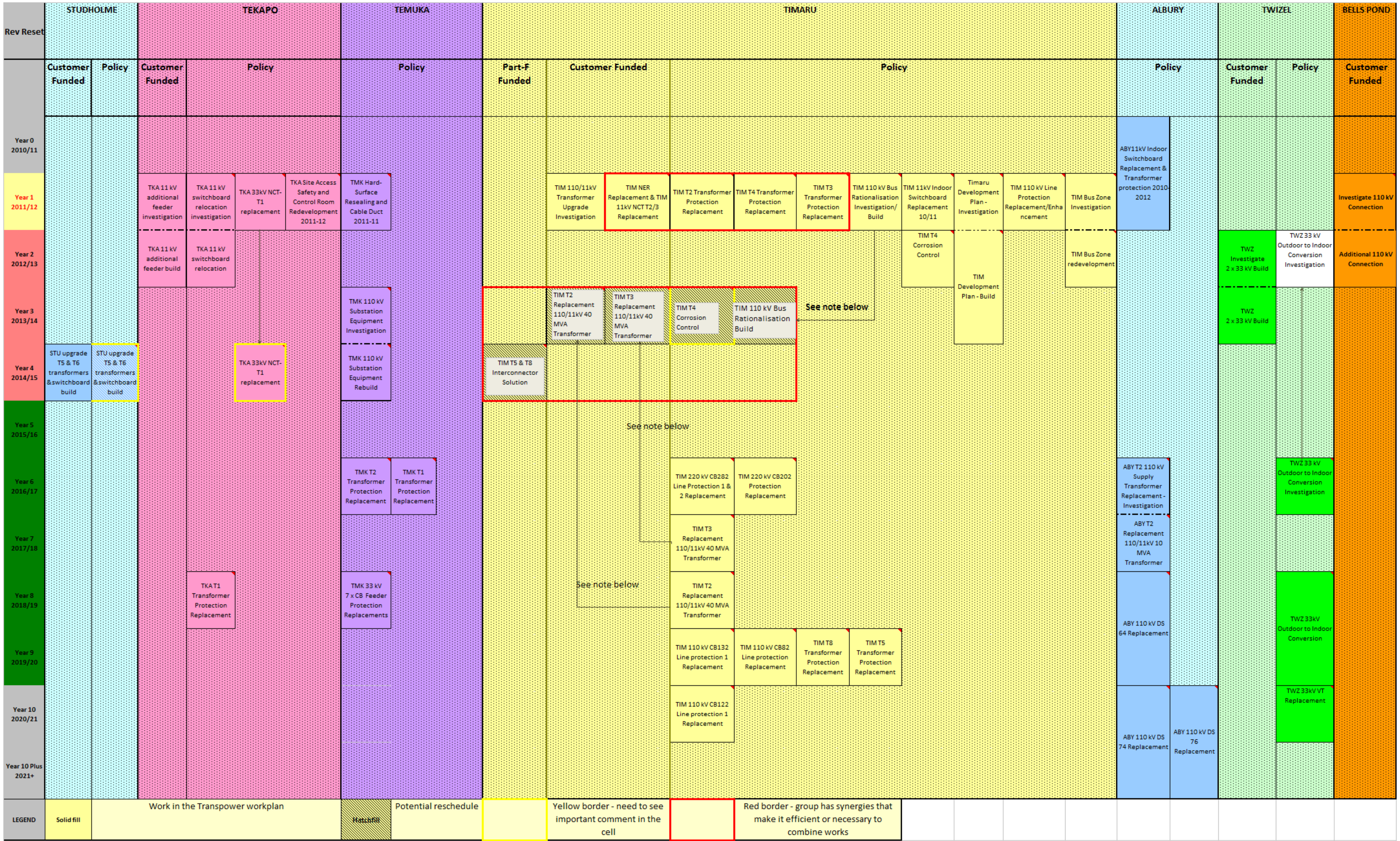
TIMARU CENTRAL CITY LV DISTRIBUTION SYSTEM


TIMARU CITY
10506

APPENDIX H

AEL's Tranpower GXP Worksplan

(Tetris Diagram)



Note: Solid fill blocks are the positions of the work in the TP workplan. Potential shifts, including at customer request, are shown in hatched fill. Any movement from the original dates may result in a need to review the source of funding. The amended funding source is shown in the diagram.
Policy projects during 2012-2015 are locked by Revenue Reset
Exclusions: -
This workplan does not include
-the replacement of Battery Banks, which occur every 8 years at any substation with 2 years between replacement of Battery Bank 1 and Battery Bank 2
- replacement of Airconditioning systems which are replaced every 10 years
- minor site works, such as replacing perimeter fencing

APPENDIX I

Commerce Commission Information Disclosure Schedules 11a to 13

Company Name: **Alpine Energy Limited**
AMP Planning Period: **1 April 2013 – 31 March 2023**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
9	**11a(i): Expenditure on Assets Forecast**		$000 (in nominal dollars)										
10	Consumer connection		2,250	2,703	2,236	2,279	2,322	2,035	2,072	2,109	2,146	1,888	1,920
11	System growth		6,339	9,228	6,169	5,705	8,240	913	930	878	963	909	924
12	Asset replacement and renewal		2,325	3,524	3,799	2,473	2,406	2,686	2,511	2,613	2,659	2,823	2,376
13	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:												
15	Quality of supply		5,516	5,841	1,217	975	529	550	1,400	2,491	215	218	222
16	Legislative and regulatory												
17	Other reliability, safety and environment												
18	**Total reliability, safety and environment**		5,516	5,841	1,217	975	529	550	1,400	2,491	215	218	222
19	**Expenditure on network assets**		16,430	21,295	13,421	11,432	13,498	6,184	6,913	8,091	5,982	5,837	5,442
20	Non-network assets		640	1,312	666	731	691	396	655	388	336	372	486
21	**Expenditure on assets**		17,070	22,607	14,087	12,164	14,189	6,580	7,568	8,478	6,319	6,209	5,928
22													
23	*plus* Cost of financing		-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions		1,700	1,924	2,400	2,048	2,089	2,131	2,173	2,217	2,261	2,306	2,353
25	*plus* Value of vested assets												
26													
27	**Capital expenditure forecast**		15,370	20,683	11,687	10,116	12,100	4,449	5,394	6,261	4,057	3,903	3,575
28													
29	Value of commissioned assets		16,430	21,295	13,421	11,432	13,498	6,184	6,913	8,091	5,982	5,837	5,442

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
30		for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
32			$000 (in constant prices)										
33	Consumer connection		2,250	2,650	2,150	2,150	2,150	1,850	1,850	1,850	1,850	1,600	1,600
34	System growth		6,339	9,047	5,932	5,382	7,630	830	830	770	830	770	770
35	Asset replacement and renewal		2,325	3,524	3,653	2,333	2,228	2,442	2,242	2,292	2,292	2,392	1,980
36	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
37	Reliability, safety and environment:												
38	Quality of supply		5,516	5,841	1,170	920	490	500	1,250	2,185	185	185	185
39	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment		-	-	-	-	-	-	-	-	-	-	-
41	**Total reliability, safety and environment**		5,516	5,841	1,170	920	490	500	1,250	2,185	185	185	185
42	**Expenditure on network assets**		16,430	21,062	12,905	10,785	12,498	5,622	6,172	7,097	5,157	4,947	4,535
43	Non-network assets		640	1,312	640	690	640	360	585	340	290	315	405
44	**Expenditure on assets**		17,070	22,374	13,545	11,475	13,138	5,982	6,757	7,437	5,447	5,262	4,940
45													
46	**Subcomponents of expenditure on assets (where known)**												
47	Energy efficiency and demand side management, reduction of energy losses		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Overhead to underground conversion		-	-	-	-	-	-	-	-	-	-	-
49	Research and development		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
58		for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
59	**Difference between nominal and constant price forecasts**		$000										
60	Consumer connection		-	53	86	129	172	185	222	259	296	288	320
61	System growth		-	181	237	323	610	83	100	108	133	139	154
62	Asset replacement and renewal		-	-	146	140	178	244	269	321	367	431	396
63	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
64	Reliability, safety and environment:												
65	Quality of supply		-	-	47	55	39	50	150	306	30	33	37
66	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
67	Other reliability, safety and environment		-	-	-	-	-	-	-	-	-	-	-
68	**Total reliability, safety and environment**		-	-	47	55	39	50	150	306	30	33	37
69	**Expenditure on network assets**		-	234	516	647	1,000	562	741	994	825	890	907
70	Non-network assets		-	-	26	41	51	36	70	48	46	57	81
71	**Expenditure on assets**		-	234	542	689	1,051	598	811	1,041	872	947	988

Schedule 11a:Report of Forecast Capital Expenditure continued

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
72							
73	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18
74	**11a(ii): Consumer Connection**						
75	*Consumer types defined by EDB**	$000 (in constant prices)					
76	[EDB consumer type]						
77	[EDB consumer type]						
78	[EDB consumer type]						
79	[EDB consumer type]						
80	All customer connections	2,250	2,650	2,150	2,150	2,150	1,850
81	**include additional rows if needed*						
82	**Consumer connection expenditure**	2,250	2,650	2,150	2,150	2,150	1,850
83	*less* Capital contributions funding consumer connection	233	242	400	408	359	701
84	**Consumer connection less capital contributions**	2,017	2,408	1,750	1,742	1,791	1,149
85	**11a(iii): System Growth**						
86	Subtransmission	2,452	3,500	2,000	2,000	3,100	-
87	Zone substations	2,137	3,050	500	2,100	3,800	-
88	Distribution and LV lines	923	1,317	502	502	-	-
89	Distribution and LV cables	224	320	500	500	500	500
90	Distribution substations and transformers	273	390	-	-	-	-
91	Distribution switchgear	140	200	2,000	-	-	-
92	Other network assets	189	270	430	280	230	330
93	**System growth expenditure**	6,339	9,047	5,932	5,382	7,630	830
94	*less* Capital contributions funding system growth	656	827	1,103	1,022	1,275	315
95	**System growth less capital contributions**	5,683	8,220	4,829	4,360	6,355	515

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
103							
104	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18
105	**11a(iv): Asset Replacement and Renewal**	$000 (in constant prices)					
106	Subtransmission						
107	Zone substations	421	638	715	50	50	200
108	Distribution and LV lines	443	671	1,750	1,450	1,400	1,400
109	Distribution and LV cables	-					
110	Distribution substations and transformers	429	650	430	300	320	320
111	Distribution switchgear	472	715	458	483	408	472
112	Other network assets	561	850	300	50	50	50
113	**Asset replacement and renewal expenditure**	2,325	3,524	3,653	2,333	2,228	2,442
114	*less* Capital contributions funding asset replacement and renewal	241	322	679	443	372	926
115	**Asset replacement and renewal less capital contributions**	2,084	3,202	2,974	1,890	1,856	1,516
116	**11a(v):Asset Relocations**						
117	*Project or programme**						
118	[Description of material project or programme]						
119	[Description of material project or programme]						
120	[Description of material project or programme]						
121	[Description of material project or programme]						
122	[Description of material project or programme]						
123	**include additional rows if needed*						
124	All other asset relocations projects or programmes						
125	**Asset relocations expenditure**	-	-	-	-	-	-
126	*less* Capital contributions funding asset relocations						
127	**Asset relocations less capital contributions**	-	-	-	-	-	-
128							
129	**11a(vi):Quality of Supply**						
130	*Project or programme**						
131	Overhead Lines, new, refurbished & upgraded	184	195	-	-	-	-
132	Distribution Substations, including transformer, regulators, ring main units, etc.	434	460	270	160	110	150
133	Underground Cables, including overhead to underground conversions	1,800	1,906	200	510	180	250
134	Zone Substations, including load control plants	378	400	400	-	-	-
	Mobile Plant	2,248	2,380	-	-	-	-
135	System Development	472	500	300	250	200	100
136	**include additional rows if needed*						
137	All other quality of supply projects or programmes	-	-	-	-	-	-
138	**Quality of supply expenditure**	5,516	5,841	1,170	920	490	500
139	*less* Capital contributions funding quality of supply	571	534	218	175	82	190
140	**Quality of supply less capital contributions**	4,945	5,307	952	745	408	310
141							
142	**11a(vii): Legislative and Regulatory**						
143	*Project or programme**						
144	[Description of material project or programme]						
145	[Description of material project or programme]						
146	[Description of material project or programme]						
147	[Description of material project or programme]						
148	[Description of material project or programme]						
149	**include additional rows if needed*						
150	All other legislative and regulatory projects or programmes						
151	**Legislative and regulatory expenditure**	-	-	-	-	-	-
152	*less* Capital contributions funding legislative and regulatory						
153	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
161							
162	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18
163	**11a(viii): Other Reliability, Safety and Environment**						
164	*Project or programme**	$000 (in constant prices)					
165	[Description of material project or programme]						
166	[Description of material project or programme]						
167	[Description of material project or programme]						
168	[Description of material project or programme]						
169	[Description of material project or programme]						
170	**include additional rows if needed*						
171	All other reliability, safety and environment projects or programmes						
172	**Other reliability, safety and environment expenditure**	-	-	-	-	-	-
173	*less* Capital contributions funding other reliability, safety and environment						
174	**Other reliability, safety and environment less capital contributions**	-	-	-	-	-	-
175							
176							
177							
178	**11a(ix): Non-Network Assets**						
179	**Routine expenditure**						
180	*Project or programme**						
181	Information Technology	500	500	500	500	500	150
182	Equipment	50	75	50	100	50	75
183	Vehicles	90	225	90	90	90	135
184	[Description of material project or programme]						
185	[Description of material project or programme]						
186	**include additional rows if needed*						
187	All other routine expenditure projects or programmes						
188	**Routine expenditure**	640	800	640	690	640	360
189	**Atypical expenditure**						
190	*Project or programme**						
191	Property	-	512	-	-	-	-
192	[Description of material project or programme]						
193	[Description of material project or programme]						
194	[Description of material project or programme]						
195	[Description of material project or programme]						
196	**include additional rows if needed*						
197	All other atypical projects or programmes						
198	**Atypical expenditure**	-	512	-	-	-	-
199							
200	**Non-network assets expenditure**	640	1,312	640	690	640	360

Company Name	Alpine Energy Limited
AMP Planning Period	1 April 2013 – 31 March 2023

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7												
8	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,127	1,485	1,484	1,516	1,528	1,533	1,532	1,541	1,541	1,512	1,512
11	Vegetation management	103	123	123	125	126	127	127	127	127	125	125
12	Routine and corrective maintenance and inspection	2,475	2,946	2,945	3,009	3,033	3,044	3,041	3,059	3,059	3,002	3,002
13	Asset replacement and renewal	1,539	798	797	815	821	824	823	828	828	813	813
14	**Network Opex**	5,245	5,352	5,349	5,465	5,508	5,528	5,523	5,557	5,556	5,452	5,452
15	System operations and network support	5,695	5,842	6,008	6,172	6,321	6,478	6,641	6,811	6,986	7,168	7,354
16	Business support	4,451	4,539	4,773	4,898	5,018	5,024	5,060	5,116	5,192	5,284	5,409
17	**Non-network opex**	10,146	10,381	10,781	11,071	11,339	11,502	11,701	11,927	12,178	12,451	12,763
18	**Operational expenditure**	15,391	15,732	16,130	16,536	16,847	17,030	17,225	17,483	17,734	17,903	18,215

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
19												
20	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,127	1,463	1,454	1,455	1,436	1,411	1,379	1,356	1,325	1,270	1,240
23	Vegetation management	103	121	120	120	119	117	114	112	110	105	103
24	Routine and corrective maintenance and inspection	2,475	2,904	2,886	2,889	2,851	2,800	2,737	2,692	2,631	2,522	2,462
25	Asset replacement and renewal	1,539	786	781	782	772	758	741	729	712	683	666
26	**Network Opex**	5,245	5,275	5,242	5,247	5,178	5,086	4,971	4,890	4,778	4,580	4,471
27	System operations and network support	5,695	5,759	5,888	5,925	5,942	5,960	5,977	5,994	6,008	6,021	6,030
28	Business support	4,451	4,474	4,677	4,702	4,717	4,622	4,554	4,502	4,465	4,438	4,435
29	**Non-network opex**	10,146	10,233	10,565	10,628	10,659	10,582	10,531	10,495	10,473	10,459	10,466
30	**Operational expenditure**	15,391	15,508	15,807	15,875	15,837	15,667	15,502	15,385	15,252	15,039	14,937
31	**Subcomponents of operational expenditure (where known)**											
32, 33	Energy efficiency and demand side management, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Insurance	172	175	179	182	186	190	193	197	201	205	209
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
39												
40	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	21	30	61	92	123	153	185	216	242	272
43	Vegetation management	-	2	2	5	8	10	13	15	18	20	23
44	Routine and corrective maintenance and inspection	-	42	59	120	182	243	304	367	428	480	540
45	Asset replacement and renewal	-	11	16	33	49	66	82	99	116	130	146
46	**Network Opex**	-	76	107	219	330	442	552	667	778	872	981
47	System operations and network support	-	83	120	247	379	518	664	817	978	1,147	1,324
48	Business support	-	65	95	196	301	402	506	614	727	845	974
49	**Non-network opex**	-	148	216	443	680	920	1,170	1,431	1,705	1,992	2,297
50	**Operational expenditure**	-	224	323	661	1,011	1,362	1,722	2,098	2,483	2,865	3,279

ALPINE ENERGY LIMITED

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2013 – 31 March 2023**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)						
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.04%	7.44%	82.62%	9.91%	-	3	7.47%
11	All	Overhead Line	Wood poles	No.	0.06%	10.11%	80.74%	9.09%	-	3	10.17%
12	All	Overhead Line	Other pole types	No.						[Select one]	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	2.54%	0.32%	97.13%		3	2.54%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km						[Select one]	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	11.50%	88.50%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km						[Select one]	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km						[Select one]	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km						[Select one]	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km						[Select one]	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km						[Select one]	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km						[Select one]	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km						[Select one]	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km						[Select one]	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	4.00%	44.00%	52.00%	-	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.						[Select one]	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.						[Select one]	
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	61.91%	38.09%	-	3	4.76%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.					100.00%	1	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.					100.00%	1	N/A
30	HV	Zone substation switchgear	33kV RMU	No.						[Select one]	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.						[Select one]	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.				100.00%		1	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	16.81%	29.21%	53.98%	-	3	16.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.					100.00%	1	N/A

42					Asset condition at start of planning period (percentage of units by grade)						
44	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	14.71%	47.06%	38.23%	-	3	12.00%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km					100.00%	1	
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km						[Select one]	
48	HV	Distribution Line	SWER conductor	km						[Select one]	
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	2.00%	25.00%	73.00%	-	3	-
50	HV	Distribution Cable	Distribution UG PILC	km	-	-	84.00%	16.00%	-	3	-
51	HV	Distribution Cable	Distribution Submarine Cable	km						[Select one]	
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.					100.00%	1	
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.					100.00%	1	
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.					100.00%	1	
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.					100.00%	1	
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.					100.00%	1	
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.53%	1.51%	54.46%	43.49%		3	0.23%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.21%	1.91%	38.47%	58.41%		3	1.21%
59	HV	Distribution Transformer	Voltage regulators	No.					100.00%	1	
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.					100.00%	1	
61	LV	LV Line	LV OH Conductor	km	-	7.27%	17.35%	75.38%		1	-
62	LV	LV Cable	LV UG Cable	km	-	3.00%	74.00%	23.00%	-	3	-
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km					100.00%	1	
64	LV	Connections	OH/UG consumer service connections	No.					100.00%	1	
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.					100.00%	1	
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot					100.00%	1	
67	All	Capacitor Banks	Capacitors including controls	No.					100.00%	1	
68	All	Load Control	Centralised plant	Lot	20.00%	40.00%	20.00%	20.00%		3	20.00%
69	All	Load Control	Relays	No.	45.11%				54.89%	2	45.11%
70	All	Civils	Cable Tunnels	km						[Select one]	

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2013 – 31 March 2023**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Albury	2	-	N	3	-	-	-	Transformer	AEL step up to Fairlie, main site tx is TPs at 6 with 4.18 load and 6+ generation. Transfer from PLP (TIM GXP).
10	Balmoral	-	-	N	-	-	-	-	Transformer	Transfomer is being taken out of service in 2013.
11	Bell's Pond	6	-	N	4	-	-	-	Transformer	HV winding rating, MV and LV 15 each. Transfer from STU.
12	Clandeboye 1	13	20	N-1	-	65%	20	65%	No constraint within +5 years	Load is an estimate.
13	Clandeboye 2	12	25	N-1	-	48%	25	48%	No constraint within +5 years	Load is an estimate.
14	Fairlie	2	-	N	1	-	-	-	Transformer	3 MVA replaced by 5/6.25 MVA in 2013. Transfer from ABY.
15	Geraldine	7	-	N	4	-	9	84%	Subtransmission circuit	assumes 2nd 5/6.25/9 MVA ex-RGA in T1 position. Transfer from RGA & TMK.
16	Glentanner	0	-	N	-	-	-	-	Transformer	Load is an estimate
17	Haldon Lilybank	0	-	N	-	-	-	-	Transformer	Load is an estimate
18	Pareora	8	15	N-1	4	52%	15	65%	No constraint within +5 years	Lines do not allow 30 capacity. Transfer from STU & TIM.
19	Pleasant Point	4	-	N	3	-	-	-	Transformer	Transfer from TIM & TMK & ABY.
20	Rangitata	7	15	N-1	4	43%	15	55%	No constraint within +5 years	Line does not allow 15 capacity. Transfer from GLD & TMK & CD1.
21	Studholme	10	11	N-1	4	94%	11	118%	Transpower	TP has 2 x 11 MVA 110/11 kV txfrs feeding AEL 11 kV swbd. Transfer from BPD & PAR.
22	Tekapo Village	3	-	N	-	-	-	-	Transformer	Load is an estimate
23	Temuka	12	25	N-1	4	48%	25	60%	No constraint within +5 years	AEL step down to local area, main site tx is TPs. Transfer from TIM & CD1 & RGA & GLD.
24	Timaru 11/33	12	25	N-1	-	49%	25	61%	No constraint within +5 years	AEL step up to Pareora/Pleasant Point, main site tx is TPs
25	Twizel Village	3	3	N-1	-	94%	3	107%	No constraint within +5 years	0
26	Unwin Hut	1	-	N	-	-	-	-	Transformer	Load is an estimate
27	[Zone Substation_19]					-			[Select one]	
28	[Zone Substation_20]					-			[Select one]	

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

30 **12b(ii): Transformer Capacity**

sch ref		(MVA)
31		
32	Distribution transformer capacity (EDB owned)	
33	Distribution transformer capacity (Non-EDB owned)	
34	**Total distribution transformer capacity**	-
35		
36	**Zone substation transformer capacity**	

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2013 – 31 March 2023**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

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

sch ref

12c(i): Consumer Connections

sch ref		Number of connections					
8	*Number of ICPs connected in year by consumer type*						
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
11	*Consumer types defined by EDB**						
12	LOW fixed charge	7,057	7,128	7,199	7,271	7,344	7,417
13	0 - 15 kVA	21,556	21,772	21,989	22,209	22,431	22,656
	45 kVA	985	995	1,005	1,015	1,025	1,035
	400V Assessed Demand	1,416	1,430	1,444	1,459	1,473	1,488
14	400V TOU	133	134	136	137	138	140
15	11kV TOU	10	10	10	10	10	11
16	33/11 Major New Investments	3	3	4	4	4	4
17	**Connections total**	31,160	31,472	31,787	32,105	32,426	32,750
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	2	2	2	2	2	2
21	Installed connection capacity of distributed generation (MVA)	9	9	9	9	9	9

12c(ii) System Demand

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
24		**Maximum coincident system demand (MW)** — for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
25		GXP demand	120	123	127	130	134	138
26	*plus*	Distributed generation output at HV and above	6	6	6	6	6	6
27		**Maximum coincident system demand**	126	129	133	137	140	144
28	*less*	Net transfers to (from) other EDBs at HV and above	1	1	1	1	1	1
29		**Demand on system for supply to consumers' connection points**	125	129	132	136	140	143
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	720	742	763	785	806	828
32	*less*	Electricity exports to GXPs	15	16	16	17	17	17
33	*plus*	Electricity supplied from distributed generation	26	26	27	28	29	29
34	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35		**Electricity entering system for supply to ICPs**	730	752	774	796	818	840
36	*less*	Total energy delivered to ICPs	698	719	740	761	782	803
37		**Losses**	32	33	34	35	36	37
38								
39		**Load factor**	67%	67%	67%	67%	67%	67%
40		**Loss ratio**	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2013 – 31 March 2023**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref

8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	52.0	52.0	52.0	52.0	49.8	47.9
12	Class C (unplanned interruptions on the network)	112.0	112.0	112.0	112.0	107.2	103.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.30	0.30	0.30	0.30	0.30	0.30
15	Class C (unplanned interruptions on the network)	1.39	1.39	1.39	1.39	1.39	1.39

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2013 – 31 March 2023**
Asset Management Standard Applied	**PAS55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	1. Asset Management Policy 2. Alpine Energy Limited Asset Management Plan 2013-2023 (2013 AMP) 3. Network group meeting notes.	Our Asset Management Policy is accessible by all staff on our intranet. The asset management plan (AMP) is reviewed and approved by senior management before being reviewed and approved by the Alpine Energy Limited (AEL) Board. Groups such as Engineering and the Drawing Office are given hard copies of the AMP. Hard copies are not distributed to all staff within AEL 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.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (e.g., as required in PAS 55 Para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	1	1. See individual AEL policies and plans, particularly p. 7 of AELs Asset management Policy.	Each of our policy documents has a strategy or objective which is compliant with and gives effect to the Asset Management Policy (p. 7, Asset Management Policy).	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (e.g., as required by PAS 55 Para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 Para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	1	1. Asset Management Plan, chapters 6 & 8.	The maturity level of '2' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was reduced to 1. Refer to chapter 6, Life Cycle Asset Management Planning and chapter 8, Evaluation of Performance (also see subsection 8.4.5, Lifecycle Asset Management Planning) of our 2013 AMP.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	1. Asset Management Plan, chapter 6 & App C for CAPEX data. 2. OPEX data.	Refer to chapter 6, Life Cycle Asset Management Planning and Appendix C, Network CAPEX and summary forecasts, of our 2013 to 2023 AMP. This appendix lists the projects currently underway or about to start in the next twelve months.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering Managers.	The organisation's asset management plan(s).

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2013 – 31 March 2023**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2013 – 31 March 2023**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	Copies of our AMP are circulated to our subsidiary Netcon and to other large contractors. We do not provide copies to customers but will do so on request.	A copy of our AMP is available, at reception and on our website. Interested persons can request a hard copy through our office or access a copy form our website at http://www.alpineenergy.co.nz/	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2	1. 2013 AMP, chapter 7, section 2.7, and Fig 2.2 at page 21 2. Job descriptions: Network Manager; Asset Manager; Maintenance Manager etc. 3. Nimbus (Accounting)Software.	Refer to chapter 7 , Accountabilities for Asset Management of our 2013 AMP. Section 2.7 includes discussion of accountability at ownership level, governance, executive, management, operational, works and includes accountability of Netcon our subsidiary. Figure 2.2: Accountabilities for Asset Management at page 21 of our 2013 AMP shows the accountabilities at the ownership level. Detailed role descriptions are held by the Training and Compliance Manager for the Network Manager, the Asset Manager, Maintenance Manager, etc. NIMBUS, our financial system, records who has been designated to project manage specific jobs.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering Managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	1. OPEX Data 2. Netcon Purchase order 3. Netcon Service Level Agreement 4. Service Level Agreement 5. Job descriptions for senior management 6. Our AMP 7. Business Process Mapping (BPM) of processes 8. Board papers approving unplanned works and monthly financial/variance analysis reports. 9. Training Records 10. Board meeting minutes.	Since 2005 we have recruited additional staff to ensure that our work plan can be completed. For example, in 2005 AEL had one network engineer and eight support staff. In 2012 AEL had grown to six network engineers and twelve support staff. A schedule of delegated authorities is held in the AMP. A Service Level Agreement is held between AEL and Netcon. The Board approves unplanned works and notes monthly variances through the Board papers circulated monthly to the Board and to senior management. Board meeting minutes are held by the Executive Assistant to the CEO. Field service training and training records as well as job descriptions are held by the Training and Compliance Manager.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering Managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	1	1. H&S Management System includes a section on Reporting and Monitoring, pp. 16-19 2. Emergency Preparedness Plan 3. Network Policy Public Safety Management System 4. Participant Outage Plan, chapter 4 5. Specific documents on the Network Folder for contingency planning 6. AMP, chapter 7 7. Risk Register in the Health and Safety Vault database.	Refer to the Health & Safety Management System, (Reporting and Monitoring, pp. 16-19), the Emergency Preparedness Plan, the Network Policy Public Safety Management System, and the Participant Outage Plan. The Participant Preparedness Plan chapter 4, General Control During an Emergency includes contingency planning including: site recovery order, critical facility by substation, customer contacts, and essential service contacts. Chapter 7, Emergency Response and Contingency Planning, of our 2013 AMP includes discussion of our business continuity planning, emergency preparedness plan, participant outage plan, specific contingency plans, and civil defence emergency management. The Training and Compliance Manager maintains our Risk Register and Incident Reporting through the Health and Safety Vault database (the Vault).	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The Manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	2	1. Detailed position descriptions for the Asset Manager and senior management descriptions 2. Section 2.7 of our 2013 AMP includes detailed discussion of our accountabilities for asset management 3. AEL Organisational Chart 4. BPM of processes 5. Safety Management System audit reports 6. Board meeting minutes on staffing levels and current / future competency requirements 7. Service Level Agreement with Netcon.	The maturity level of '2' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. The Asset Manager is responsible for managing asset delivery in accordance with our AMP policy. The team includes both permanent and contract staff for one-off projects. A role description for the Asset Manager is held with the Training and Compliance Manager who also holds Safety Management audit reports in the Vault database. Refer to section chapter 2.7 of our 2013 AMP for detailed discussion of our accountably for the management of our assets.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets e.g., Para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in Para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that Managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	1	1. Service Level Agreement from Netcon 2. 2013 AMP, section 2.1 3. BPM of HR processes 4. Board reports and meeting minutes discussing budgets, variance analysis, staff structures/requirements, and CAPEX and OPEX spending	The Service Level Agreement held between AEL and Netcon includes assurance around resourcing and planning. Refer to section 2.1, Purpose of the AMP which states that a purpose of our AMP to ensure that we have made adequate provision for funding all phases of the network lifecycle. The Board is consistently apprised of our progress with the work programme as specified by our AMP. Budgets and variance analysis is carried out by senior management in particular the Corporate Services Manager and the Network Manager. Board meeting minutes are held by the Executive Assistant to the CEO.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's Managers involved in day-to-day supervision of asset-related activities, such as frontline Managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2	1.Schedule 13 Senior Management Meeting, Dec 12 and 9 Jan, 2012/13 meeting notes 2. Network Meeting notes 3. Job descriptions of senior management 4. Board reports and meeting minutes 5. Service Level Agreement held with Netcon 6. Hard copies of standards manuals 7. The AMP contains a schedule of delegated authorities 8. Emergency recovery and disaster response arrangements.	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 around the meeting of the AMP requirements is kept to those people that are considered to be relevant and who can directly influence outcomes. Our Training and Compliance Manager holds copies of all AEL job descriptions. Discussion of our progress with our AMP requirements and budgeting are held with the Board by senior management on a monthly basis. In particular the Corporate Services Manager and the Network Manager. Minutes are held by the Executive Assistant to the CEO. Engineers keep hard copies of standards manuals. Emergency recovery and disaster response arrangements are detailed in Safety Management System by the Health and Safety Manager.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (e.g., PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	1. Netcon Service Level Agreement 2. Spread sheets for maintenance status of capacitors, closers, regulators, substations, etc. 3. Nimbus accounting software generate automated reports 4. New connection sign off sheets.	Planned maintenance on all AEL regulated assets are held and delegated to Netcon. The planning reports are held by Netcon's Technical Manager. Nimbus keeps track of job numbers and work orders between Netcon and AEL. New Connection data is held by the New Connection Team Leader. Our ICP database administered by IT Services.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (e.g., PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The Manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	1	1. Training and Compliance Manager maintains staff training records and a Competency Matrix 2. EEA meeting attendance records 3. Human Resource plans include HR BPMs.	The maturity level of '2' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Our training includes both safety and competency requirements, as described in training records and the competency matrix held by the Training and Compliance Manager. Training for fire wardens (Fire and Safety Training Ltd), driving, and first aid is provided by external certified persons. Our engineers attend Electrical Engineers Association forums to maintain their professional certifications. The Training and Compliance manager seeks feedback on courses, training, and forums attended through the group managers to identify good/bad courses.	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	1. AEL Network Policy chapters 3 and 4. 2. Competency Matrix training plan. 3. Chartered Professional Engineers Act 2002.	The maturity level of '1' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 2. Refer to chapter 3, Competency Classifications and chapter 4, Network Authorisation, of the AEL Network Policy: Network Authorisation and Competency. The Training and Compliance Manager, keeps a training, licensing, and competency register (competency matrix). The Training and Compliance manager seeks feedback on courses, training, and forums attended through the group managers to identify good/bad courses. Competencies for professional engineers are found under the Chartered Professional Engineers Act 2002. Engineers must do a review of competence to practice in their field of expertise. Through the AMMAT process we have identified gaps in our formal record keeping for the training undertaken for some projects. Training for specialised projects such as substation refits relies on specific 'on the job' training. Gaps exist where this specific on the job training has not been formally recorded. We intend to review of process for recording training to try to capture this specific on the job training of our staff.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (e.g., PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	1	1. AEL Network Policy chapters 3 and 4 2. Competency Matrix Training Records 3. BPM for AEL HR processes 4. Netcon Service Level Agreement 5. The AEL Safety Management System (SMS) audit reports.	The maturity level of '2' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was reduced to 1. Refer to chapter 3, Competency Classifications and chapter 4, Network Authorisation of the AEL Network Policy: Network Authorisation and Competency of the AMP. The Training and Compliance Manager maintains a competency matrix and training records for each AEL staff member. The Training and Compliance Manager also holds copies of the SMS audit reports.	A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	1. Asset Management Policy 2. 2013 AMP 3. Netcon Service Level Agreement 4. Senior management job descriptions.	The maturity level of '2' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Copies of our AMP and Asset Management Policy are available on our website at www.alpineenergy.co.nz and http://imgserv/ respectively. Our approval process of our AMP requires that the draft 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. A soft copy of the AMP is accessible by all staff on the shared drive and to interested persons on our website. The Service Level Agreement is based around key elements of the AMP as it is devised under the watch of senior management. Job descriptions for key personnel show the need to communicate key AMP information.	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	1	1. BPM project 2. Use of Deloittes "New Industry Print" software.	We have completed BPM training, and the mapping of our business processes is near completion (target date 31 March 2013). Once complete we will have documented all of our processes. The BPM's will show the interactions between all of our processes. The mapping has been done the BPM project Manager holding discussions with key AEL staff to identify existing processes, in the first instance and then follow up meeting with all other staff identified in the process. Once the maps are completed copies will be made available to all AEL staff to review and provide comment to. These are mapped using Deloittes "New Industry Print" software. Information from this will be used to develop in house software where appropriate to improve and record key processes.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (e.g., s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	1. BPM project 2. Independent Review of Internal AMMAT. Ratings from Utility Consultants. 3. Board meetings minutes and reports 4. Deloittes strategic IT review.	The maturity level of '1' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 2. The importance, relevance, and key information of our AMP is discussed regularly by senior management meetings and our Board at weekly and monthly meetings respectively . Our AMMAT scores and process was externally reviewed to get surety of the result and process taken. Board papers are circulated to all senior managers. In 2011 we had Deloittes carryout an external review of our existing information technologies. The review identified the need to replace some of our exiting systems including our asset management system. It was determined that our BPM project could scope our overall company wide needs.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering Managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	1	1. AEL IT Policy Statement 2. GIS and gentrack 3. Deloittes AEL strategic IT review 4. AEL AMP 5. Creation of an IT Manager's position.	The Alpine Energy Limited IT Policy Statement gives a broad outline of our overall IT policy. Data 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. Since the Deloittes review discussed above we have engaged a IT Manager and Business Analyst to complete the BPM project and are looking at a staged approach to the implementation of new systems.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (e.g., s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	1. Appointment of IT Manager 2. Review of the IT system by Deloittes 3. Business Process Mapping 4. Board meetings and minutes.	The maturity level of '1' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 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.	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	1	1. 2013 AMP, chapter 7 2. Health & Safety Management System, p.40 and reports 3. EEA Asset Health Indicator Forum participant register 4. BPM 5. Board meeting minutes and board reports 6. Demand forecasts by the Asset Manager 7. Asset inspection data and sheet 8. Asset failure investigation report for Clayton Road outage 9. Asset condition reports from dissolved gas analysis (DGA) and partial discharge testing.	Refer to chapter 7, Risk Management of our 2013 AMP. Section 7.1 discusses risk from identification (also see subsection 7.1.2.) through to risk management improvements (see subsection 7.1.6.). Tables 7.1 to 7.5 give a pictorial overview of risk related asset management. Reporting is a function of the Training and Compliance Manager. The Health and Safety Management System details the process of the Hazard Register (p.40). Engineering staff have recently been to an Asset Health Indicator Forum run by the Electricity Engineers Association. Demand forecasts are completed by the Asset Manager for Transpower, both in summer and winter. Asset inspection for overhead lines is recorded by the Project Engineer. Larger failures may be investigated by the Senior Project Engineer, such as a recent outage on Clayton Rd. Asset condition reports are completed for dissolved gas analysis for all transformers above 3 MVA and partial discharge testing is completed every 6 months by contracted parties under the Asset Manager.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (e.g., Para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	1	1. 2013 AMP, subsection 7.1.6 2. Health & Safety Management System, section 3. pp. 30,38 3. Competency Matrix 4. Hazard and Condition Review, Training Needs Analysis with Training and Compliance Manager 5. Senior management job descriptions.	Refer to subsection 7.1.6. of the 2013 AMP, plans to improve the management of risk 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. See also section 3, Hazard Identification Assessment & Management, from the Health and Safety Management System, which includes a small section on training (p.30) and also Step 6 Monitor and Review (p.38) that discusses the involvement of all personnel in the risk management process and encourages ownership in the risk management process and subsequent development of hazard controls and other corrective measures", under Communicate and Consult. A Competency Matrix is held in our shared drive. The Training and Compliance Manager operates a Hazard Review and a Condition Review process, as well as a training needs analysis spread sheet and a competency matrix to determine training needs.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	1	1. Health and Safety Management System, pp.10,11 2. 2013 AMP, section 1.1 purpose of the plan 3. Training and Compliance Manager role description 4. Public Safety Management System, p. 19	Acts, regulatory codes, standards etc. are found within the specific policy documents that each relate to. For the Health and Safety Management System see p. 10, Associated Documents and References for National Standards. Also on p.11, under the Health & Safety Roles & Responsibilities, Reference section are further national standards etc. The 2013 AMP includes a note under the purpose statement (p. 1-7) that the Plan must comply with Commerce Commission information disclosure requirements. References to various legislative requirements are included throughout the 2013 AMP. A position description is also held for the Training and Compliance Manager whose role it is to maintain a regulatory and codes information/database. See p. 19, Legislation, in the Public Safety Management System, which states [t]he Compliance and Training Manager is charged with ensuring that Management and employees are kept fully appraised of any updates to relevant legislation and statutory requirements.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (e.g., PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	1. 2013 AMP, chapter 5 and Appendix C 2. Load growth Data 3. Engineering design reports from Mitton Electronet 4. Board reports 5. Service Level Agreement held with Netcon. 6. Netcon maintenance schedule 7. Powerco procedures have been adapted for AEL.	The maturity level of '1' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 2. Chapter 5, Network Development Planning, of our 2013 AMP shows the process for asset planning and decision making. There are not specific documents/ processes for acquisition, design, etc. however, individual projects that are either under way or planned can be found at section 5.9 and in Appendix C. At section 5.9 each main asset type is described in terms of its current state and proposed plans. Chapter 5 also provides our prioritisation of network development, including options to meet demand, (subsection 5.2.1) and choosing the best option (subsection 5.2.3). Section 5.1 outlines our planning criteria and includes at Table 5.1 a description of our approach to planning asset development. Chapter 5 includes discussion around our planning criteria and assumptions, prioritisation of network developments, demand forecasts, and analysis of network development options. We operate an 'open door' policy to new customer projects.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (e.g., PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset Managers, design staff, construction staff and project Managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	1. 2013 AMP, chapters 4 and 6 2. Asset Manager role description 3. Netcon SLA 4. Fortnightly meetings between Netcon and the AEL Asset Manager 5. Netcon spread sheets outlining the basic maintenance status 6. Powerco standards adopted to suit AEL 7. Asset commissioning check sheet.	The maturity level of '1' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 2. Refer to Chapter 4, Service Levels, and chapter 5, Network Development Planning, of our 2013 AMP. Chapter 6, Life Cycle Asset Management Planning, includes discussion around routine and preventative inspection and maintenance and performance programmes. The chapter discusses that at AEL the overall management of maintenance is the responsibility of the Asset Manager who sets the policies and procedures within the bounds of the AMP. The Asset Manager is also responsible for the yearly updating and editing of the AMP with the assistance of various other individuals and departments within AEL The Asset Manager has a position description held with the Training and Compliance Manager. Commissioning check sheets have recently been completed by the Network Manager.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (e.g., as required by PAS 55 s 4.5.1).	Asset Managers, operations Managers, maintenance Managers and project Managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	1. 2013 AMP, chapter 6 and 8 2. Network Policy: Public Safety Management System, p. 21 3. AEL Network Policy: Plant and Transformer Maintenance. 4. Fortnightly meetings between Netcon and the AEL Asset Manager. 5. Netcon spread sheets outlining basic maintenance status.	The maturity level of '2' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Refer to subsection 6.8 Routine and Preventive Inspection, Maintenance and Performance, of our 2013 AMP. Also refer to p.21 Asset Inspection and Maintenance, of the Network Policy Public Safety Management System. For full details on maintenance refer to the following: • Network Policy – Plant and Transformer Maintenance • Evaluation of Performance as discussed at chapter 8 of our 2013 AMP. Our network performance, SAIDI, SAIFI and CAIDI measures, are discussed at chapter 8 of our 2013 AMP. Works implementation performance of new assets and existing assets is discussed at subsections 8.3.1. and 8.3.2 of our 2013 AMP respectively. In 2011 we implemented a new financial system which will make reporting and assessment more automated and efficient from next year on. AEL will continue dedicating resource to identify and implement areas for performance improvement (see subsection 8.3.2., p.8-9 of our 2013 AMP).	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2	1. Asset Management Policy, chapter 7 2. 2013 AMP, chapter 6 3. AEL Emergency Preparedness Plan, chapter 2 & 3 4. AEL Network Plant and Transformer Maintenance, section 1, p. 8 5. Health & Safety Management System, p. 11 6. Participant Outage Plan, chapter 3.1 7. Plant Fault Form 9. Job descriptions of Senior Management 10. Use of Powerco standards adopted for AEL.	Refer to section 7.3, Asset Management Policy for Maintenance, and subsections 7.3.1, Deferred Maintenance 7.3.2, General Maintenance, and 7.3.3, Responsibilities, of our 2013 AMP. Also see chapter 6, AMP Life Cycle Asset Management Planning, particularly, section 6.8, Routine and Preventive Inspection, Maintenance and Performance Programmes and subsection 6.8.1, Maintenance Policies. For our emergency procedures refer to responsibilities outlined at chapters 2 and 3 of our Emergency Preparedness Plan, section 1 (p.8) of our Electricity Network Plant and Transformer Maintenance, and page 11 of the Health and Safety Management System. Further evidence can be seen under Responsibilities in our Participant Outage Plan, (refer to chapter 3.1) (Authorisation to Activate Participant Outage Plan). See also a Plant Fault form. Job descriptions are held by the Training and Compliance Manager. The Asset Manager maintains Powerco standards adopted for AEL.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Alpine Energy Limited**
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Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	1. 2013 AMP, chapter 8 2. External review of 2013 AMP by Utility Consultants 3. Audit reports of the Safety Management System.	The maturity level of '0' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 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.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (e.g., the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	1. 2013 AMP, subsection 6.8 2. Health & Safety Management System, section 2, p. 16 3. AEL Emergency Preparedness Plan, chapter 2 4. Hazard and Incident Report form 5. Netcon spread sheets showing general maintenance status on key assets; capacitor banks, closers, sub stations etc. 6. Netcon Service Level Agreement 7. Fortnightly meetings between Netcon and AEL Asset Manager 8. Commissioning works check sheets 9. AEL project engineers asset inspection spread sheets.	Refer to section 6.8, Routine and Preventive Inspection, Maintenance and Performance Programmes, of our 2013 AMP. Particularly subsections 6.8.1, Maintenance Policies and 6.8.2.1., Zone Substations, Ground Mounted Substations and Switchgear, Also see our Health and Safety Management System, in particular p.16 Health and Safety Reporting and Performance Monitoring. This includes a performance monitoring criteria, measures (leading indicators) and a review of H&S performance. The purpose of section 2 is the development, implementation and improvement of the safety management system. The AEL Emergency Preparedness Plan, includes chapter 2, Responsibilities and Audit Meetings between AEL and Netcon happen every two weeks and discuss the physical progress of works. Commissioning check sheets for works on transformers greater than 300KVA have been completed by the Network Manager. OHL asset inspection is conducted by AEL project engineers on an ad hoc basis and during larger faults.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	1. 2013 AMP, chapter 8 2. Staff hire; IT Manager and Network Manager, including role descriptions. 3. Acquisition of the Vault Health and Safety Data Base 4. Business Process Mapping for procurement, storage, installation of assets on Nimbus and Gentrack 5. Acquisition of Powerco procedures and standards including a cyclic review 6. HB and DGA testing results (6monthly) 7. Netcon spread sheets showing general maintenance status on key assets; capacitor banks, closers, sub stations etc. 8. Mitton Electronet design reports.	The maturity level of '1' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 2. At chapter 8, Evaluation and Performance, of our 2013 AMP we discuss the external review of our 2013 AMP. We had our AMP externally reviewed to obtain an option as to the compliance, or other wise 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. Possible AMP improvements are discussed at section 8.4 including: general improvements, service levels, lifecycle asset management planning (i.e. OPEX actual vs. budget). Other recent actions include the hiring of a new IT Manager, Network Manager, and the acquisition of the Vault Health and Safety Data base. The AEL Asset Manager holds Mitton Electronet design reports.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The Manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	1. 2013 AMP, subsection 8.4.1 2. Emails from and to the EEA, ANA, Sapere Group, Utility Consulting etc. as discussed in user guidance 3. Reports from PWC, Utility Consulting, Sapere Group, Deloittes 3. EEA conference attendance registers 4. Subscriptions to various publications.	The maturity level of '2' was reached by consensus of senior management at two meetings held in December 2012 and January 2013 respectively. Following external review the score was increased to 2. Refer to subsection 8.4.1, General improvements, of our 2013 AMP. Use of Utility Consultants for evaluation, advice given from Sapere Group, PWC, Deloittes, teleconference meetings with the ENA. Attendance at EEA, EA, Downstream and Com Com conferences confirmation of which is held on various emails. A publication list is held by the Executive Assistant to the CEO.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (e.g., by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The Manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Company Name	**Alpine Energy Limited**
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	Alpine Energy Limited
For Year Ended	31 March 2013

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

1. This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

2. 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)

3. 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 out look. 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)

4. 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 effiecncy 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.

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 enquiry, to the best of our knowledge–

a) The asset management plan 2013 to 2023 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, with the exception of the following clauses:
   - 3.8 All significant assumptions
     - 3.8.1 quantified where possible
     - 3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including
     - 3.8.3 a description of changes proposed where the information is not based on the EDB's existing business
     - 3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information
   - 3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures
   - 3.14 An overview of asset management documentation, controls and review processes
   - 12 The AMP must provide a detailed description of the lifecycle asset management processes, including—
     - 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and
     - 12.3.2 a description of innovations made that have deferred asset replacement;
   - 13 AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—
     - 13.1 a description of non-network assets;
     - 13.2 development, maintenance and renewal policies that cover them;
   - 16 AMPs must describe the processes used by the EDB to ensure that-
     - 16.1 The AMP is realistic and the objectives set out in the plan can be achieved;

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
28 March 2013

Alister John France
28 March 2013