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ASSET MANAGEMENT PLAN
// 2018

Alpine ENERGY

ASSET MANAGEMENT PLAN // 2018

ALPINE ENERGY LIMITED

Planning Period: 1 April 2018 to 31 March 2028

Disclosure date: 31 March 2018

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DIRECTORS' STATEMENT

The purpose of our 2018 to 2028 Asset Management Plan (AMP) is to provide insight and explanation of how we intend to provide electricity distribution services. We are committed to managing our distribution assets in a safe, reliable, and cost-effective manner that addresses required service levels and maintains a robust energy delivery system for our stakeholders.

The AMP has been published to meet our regulatory requirements for asset management under the Electricity Distribution Information Disclosure 2012.

Our distribution network is in a good condition. The life of different electricity distribution assets ranges widely by asset type, from 25 to 100 years. Although some parts of our network that were installed in the 1950s and 1960s, including poles, are now nearing the end of their expected service life according to the Commerce Commission's optimised deprival valuation of Fixed Assets of Electricity Lines Businesses (ODV), on average these are consistent with planned replacement rates.

We determine when to replace assets based on specific asset condition and risk. If replacing a retired asset like-for-like would be uneconomic we replace it with an appropriate alternative product. We continue to invest in network developments including new assets to serve changing and growing consumer needs, and new technologies. We are also subject to regulatory requirements that may affect our risk and economic assessments.

Two thirds of our capital expenditure over the next ten years is targeted for replacement and renewal of existing infrastructure.

Network development capital expenditure accounts for one third of the investment in our network. This investment is specifically targeted for consumer connections, reliability safety and environment projects, and network augmentation. Developments are identified that best serve our consumers for the next 50 years i.e. the average life of an electricity distribution asset.

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

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

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

The Directors
Alpine Energy Limited

DIRECTOR CERTIFICATION

CERTIFICATION FOR ASSET MANAGEMENT PLAN 2018–2028.

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

a) the Asset Management Plan 2018–2028 of Alpine Energy Limited prepared for the purposes of clause 2.6.1 and sub clauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) in all material respects complies with that determination

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

Director	Director
22/03/2018	22/03/2018
Date	Date


0800 66 11 77

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ASSET MANAGEMENT PLAN // 2018

1. EXECUTIVE SUMMARY

1. EXECUTIVE SUMMARY

1.1 OUR ASSET MANAGEMENT PLAN

This Asset Management Plan (AMP) describes how we approach life cycle asset management of our assets, and how this aligns with our overall business objectives and strategies. We aim as far as practicable, to align ourselves with ISO 55000 asset management practices that maximises long term benefits to our consumers. There are some key facts and assumptions made that influence our strategic objectives.

Our highest priority as reflected in our company values, as well as our asset management objectives, is safety of our staff, contractors, and the general public. A close second is to provide electricity distribution services at an efficient cost to our consumers through constant engagement in all aspects of asset management. We achieve this through clearly identifying the customer's requirements and how we can best accommodate their requirements through both network and non-network technologies, to provide a fit for purpose solution at an acceptable cost.

1.2 OUR AMP

In 2015 we set out to enhance the AMP in three stages, over a three year period. This year's AMP represents the final year in this process. With the development and implementation of our Asset Management Framework (AMF) suite of documents, we are now able to demonstrate how our strategic goals and objectives directs and aligns all phases of our asset management through its lifecycle. This is clear to all staff responsible for asset management down to the lowest level of various asset type fleet strategies.

Our load forecasting is currently done using both long and medium term trends. We will be reviewing and fine tuning our load forecasting methodology to ensure we align with international practice.

The various asset type fleet strategies summarises the condition and current performance of the various asset types. Details of operating and maintenance are also given. Together the aforementioned drives our capital investment programs for replacement and renewal, as well as operational expenditure budgets.

We recognise the importance of creating and maintaining our asset management capability, both of resources and systems. This is reflected in our non-network capex around information systems and asset data accuracy. Our staff complement is also deemed appropriate for asset management activities as well as resource requirements for regulatory reporting and systems administration.

Continuous professional and personal development of our staff is a priority. This will ensure our competencies with respect to asset management is maintained and enhanced.

Our services to our consumers are a high priority. The reliability of electricity supply is important to us, and has been at constant levels over the last ten years excluding major weather events. We continue to strive to improve engagement with our consumers and to provide relevant information and services in a timely manner.

1.3 OUR INVESTMENT IN OUR NETWORK TO 2028

This AMP outlines our approach to asset management and the forecast capex and opex for the planning period of 2018 through to 2028 as depicted in Figure 1.1 and Figure 1.2 overleaf. It is important to note that predictions and forecasts are based on assumptions. The expenditure below is based on our current regulatory classification under the default price path (DPP).

Figure 1.1 and Figure 1.2 overleaf shows our expenditure profile for the planning period.

1.4 INVESTMENT RECOVERY INTO THE FUTURE

The cost of alternative technologies for the independent supply of electrical power to consumers is reducing and can impact on our future revenue streams from conventional power infrastructure. We see these technologies not as a replacement of conventional infrastructure but rather an addition to it in order to provide the best solution at the right cost for our consumers. It presents us with opportunities and challenges for engineers and operators due to increased complexity.

We are currently monitoring some of these aspects on our network through the use of advanced meter information, the installation of a battery energy system on our network, as well as having a photovoltaic (PV) system installed on one of our zone substation buildings. We have also installed electric vehicle (EV) charging stations in South Canterbury to support the use of this technology and to gain an understanding of the impact on existing infrastructure.

Our response to this changing environment will vary. It could range from a pricing review to ensure that less affluent consumers do not get stuck with the conventional network costs; better utilisation of existing assets; partnering with other EDBs (with access to or ownership of new demand) or supply side technology solutions.

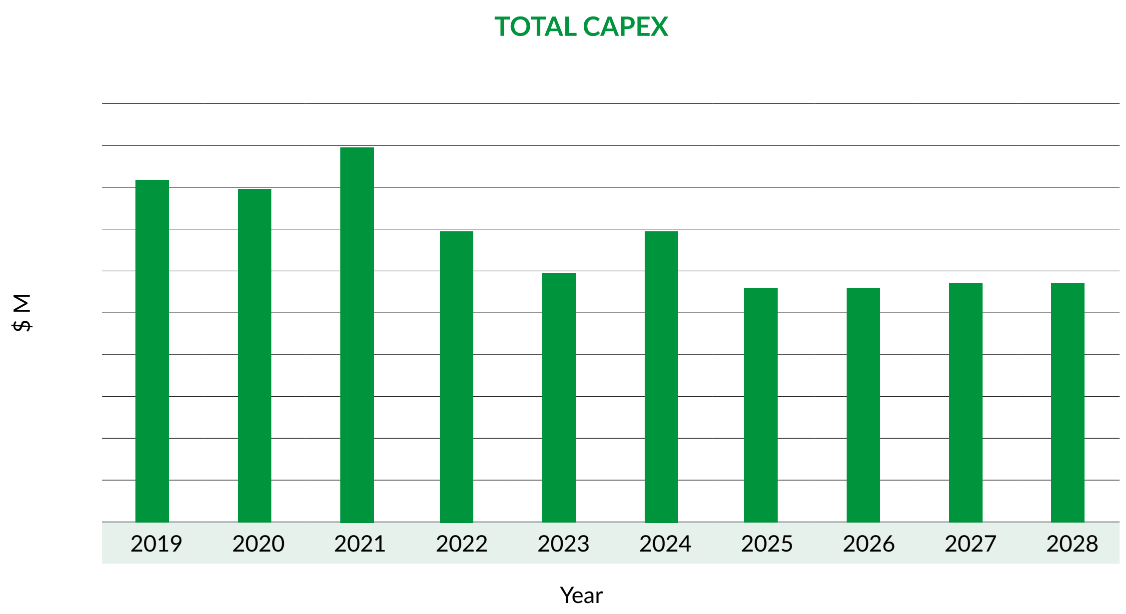

Figure 1.1 Total CAPEX for the planning period ($ M real 2018)

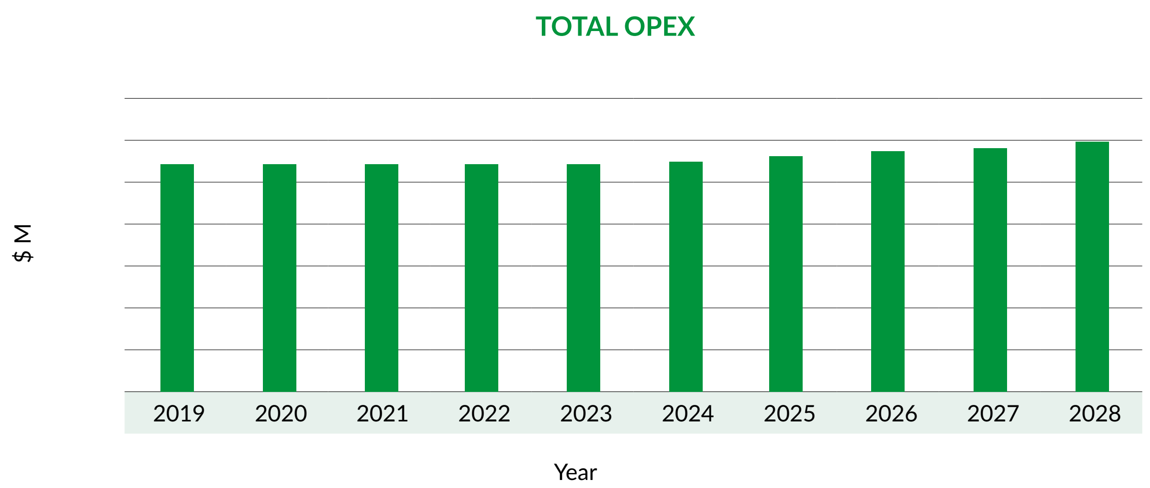

Figure 1.2 Total OPEX for the planning period ($ M real 2018)


ASSET MANAGEMENT PLAN // 2018

2. INTRODUCTION

2. INTRODUCTION

This Section outlines the AMP purpose and key assumptions. It presents our AMF including objectives and responsibilities.

2.1 THE PURPOSE OF THE PLAN

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

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

2.2 KEY FACTS AND ASSUMPTIONS

2.2.1 LOAD DEMAND

The demand for new connections during 2017 was still constant mainly as a result of the still low milk pay-outs from the dairy companies, as well as a reduction in irrigation connections. However at the time of writing this document, demand has shown a slight recovery on the back of some improvement in dairy pay-outs. Growth in demand is driven by irrigation, industrial, commercial, and domestic subdivision connections and extensions.

We recognise the fact that the economy depends on a secure and reliable electricity supply. Investment in our network will ensure that necessary network capacity is available to support increasing demand. This plan assumes the demand will be as detailed in section 5.9 for the various regions.

It is important to note the load demands as detailed in this AMP do not include any potential requirement for the Hunter Downs Water scheme, or the associated on-farm developments for this irrigation scheme. At the time of writing this, no formal application for power supply to this scheme has been received, nor has an agreement been signed for the supply of electrical power to the scheme.

2.2.2. CAPITAL INVESTMENT REQUIREMENTS

We have reported network capital investment over 10 years based on projects with high priority and certainty due to capacity or security constraints, or replacing assets that are either at the end of their useful life, or present an unacceptable risk to the company. Some projects will be conditional on third party decisions or developments such as consumer projects proceeding and resource consents being granted for irrigation schemes. Some of these could have a substantial impact on our budgets. The Capex spend on capital investment projects is summarised in section 8.2.

2.2.3. NEW TECHNOLOGY

We view distributed generation as an enabling technology for network support rather than network replacement. We assume no new technologies with the ability to entirely substitute for electricity network development will become available during the planning period. However, we do recognise the importance and the potential impact on our business. The availability of solar pumps as well as stand-alone generation consisting of PV, batteries and diesel generation in an integrated unit[1], could be viable options for rural power requirements. We are looking to align ourselves with others in the industry doing research, trials and experimentation with new technologies at a network level, to benefit from their resources and capabilities.

We also own a relatively small battery energy storage installation connected to our network for experimentation purposes, as well as a PV installation at our Tekapo substation supplying local service power requirements.

In developing and evaluating options for solutions to network capacity, reliability or security constraints, we consider new technologies.

2.2.4. SERVICE DELIVERY ARRANGEMENTS

We will continue to use Netcon Limited as our contractor for the construction and maintenance services to the majority of our network through our Alliance Agreement for the 2018/19 period. Where competencies are not available and when resources are constrained within the group, we will go to the market to obtain the most cost effective solution on behalf of the South Canterbury consumers. For minor new connections projects, our consumers can obtain the services of any network approved contractor.

We are planning to increase the percentage of contestable work to the market from 2019/20 onwards to improve efficient expenditure for our consumers.

2.2.5. COMPLIANCE

As a monopoly service provider we are subject to both economic and market regulation by the Commerce Commission and Electricity Authority respectively. During the planning period we will ensure compliance with relevant Acts and Regulations. The Plan assumes no significant change in electricity regulation.

2.2.6. LINE CHARGES

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

Under the DPP Determination, our price increases are capped at CPI + 11% each year until 31 March 2020. We are mindful of the impact price increases have on households and businesses. And we are equally mindful of our obligation to balance cost increases against the need to provide a resilient network for our growing communities.

[1] EMC's (Energy Made Clean) 'The Wedge' is a standalone power system, Powerco's Base Power suite of solutions..

[2] As at 31 March 2017

[3] Recorded in January 2015.

2.3. NETWORK AND ASSET OVERVIEW

We supply electricity to over 32,328[2] individual connection points throughout South Canterbury. Our area of supply covers approximately 10,000 km^2 and is located on the East Coast of the South Island, between the Rangitata and Waitaki Rivers, and inland to Mount Cook on the main divide as shown in Figure 3.1. Our asset base has a book value of over $197 million.

Electricity is delivered to our network via seven GXPs and one embedded generator. The network delivered 836 GWh of energy and had a half hour average coincident maximum demand of 137 MW[3] in 2017. Energy consumption is up from the previous high of 812 GWh and the half hour average coincident maximum demand of 134 MW.

Our network is made up of the asset fleets and populations as depicted.

We have 594 km of distribution and LV cables and

3,294 km of distribution and LV overhead lines, and

46,000 wood and concrete poles, connecting

29 zone substations,

25 power transformers,

16 switchboards (oil, vacuum, and SF_6) across our network,

with 365 Ring Main Units,

934 ground mounted transformers,

44 reclosers and sectionalisers,

31 voltage regulators,

4,971 pole mounted transformers,

16 capacitor banks,

link boxes and

distribution boxes to connect

32,000 ICPs supplying our consumers.

Figure 2.1 Asset fleet and populations as at 31 December 2017[4]

[4]For more detail please refer to the Information Disclosure Requirements schedule 9.

2.4 ASSET MANAGEMENT FRAMEWORK

2.4.1 OVERVIEW

This chapter describes where we are at, and our journey to improve the maturity of our asset management. To effectively and accurately set course it is important to have a clear vision of where we want to be. This is shown in the AMF depicted in Figure 2.2, and representing a suite of documents that describe how we manage our assets throughout their lifecycle. This suite of documents are being developed, and at the time of this publication we have completed all but the various fleet strategies.

No asset management system is possible without the appropriate systems to capture asset data and information to evaluate and make decisions for investment, replacement or maintenance. These systems are detailed in section 7.3.

The maturity of our asset management system is also detailed in the evaluation against the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT).

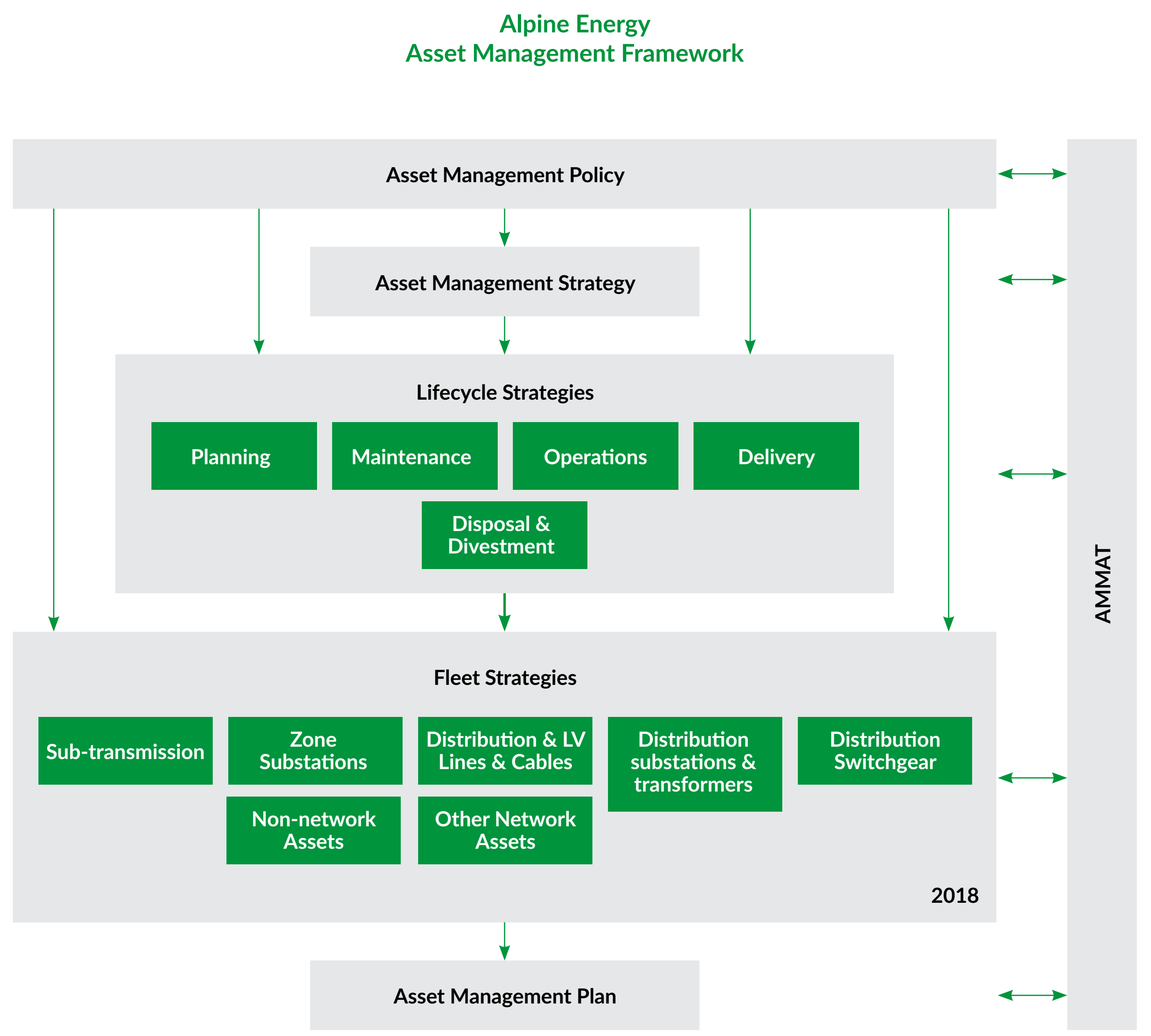

Figure 2.2 Asset Management Framework

2.4.2 CORPORATE OBJECTIVES

MISSION

Our mission is to ensure commercial success by providing safe; reliable; and efficient energy delivery and infrastructure services.

VISION

Our vision is to develop, operate, and maintain integrated energy delivery solutions for the benefit of our community.

BUSINESS GOALS

- **Shareholders** - to pursue business policies which will maximise the value of the company in the medium and long term.
- **Customers** - to deliver customers with the safe, efficient, economical and reliable 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.
- **Diversity and Growth** - to leverage capability, expertise, and know-how into new business opportunities and evolving technologies.

2.4.3 ASSET MANAGEMENT POLICY

The aim of our asset management policy is to align our asset management activities, as a service-orientated company, to our corporate objectives.

The objectives of this policy are to:

- provide the framework for our management of the distribution network assets to better align with the ISO 55000 standard
- guide the development of our network asset management strategies and objectives
- promote continuous improvement in how our assets are managed to meet consumer performance expectations.

ASSET MANAGEMENT POLICY

We are committed to ensuring that our distribution network is planned, designed, constructed, operated and maintained so as to provide a safe, reliable and efficient energy delivery service. We demonstrate our commitment by:

- always putting safety first in all asset management activities and striving for 'zero harm' to employees, contractors and members of the public
- complying with all applicable laws, legislation, regulations and codes of practice in the execution of all asset management related activities
- providing a reliable and efficient distribution network to meet our consumer expectations
- evaluating the costs and risks in delivering expected performance and maximising asset performance
- striving to ensure that asset management decisions for investment, maintenance, operational expenditure, and replacement is made on complete, accurate and timely information, and in accordance with the delegated authority
- ensuring our organisational structure and staff represents the correct mix of people and skills to develop and improve our asset management capability, and deliver the asset management objectives
- engaging with our community and improving relationships through all asset related activities that affects them
- complying with all applicable statutory and regulatory requirements in reporting on asset and asset management performance.

2.4.4. ASSET MANAGEMENT OBJECTIVES

Our asset management strategy sets the strategic direction for managing our electricity network assets. It describes how our asset management policy is used to develop our asset management objectives.

OUR ASSET MANAGEMENT OBJECTIVES ARE:

- A safe energy delivery service as described in our statement of corporate intent and with safety always as our first company value, it is appropriate that safety is the first objective in managing our assets.
- Service levels and our performance against them is a key indicator of whether we have met or exceeded our consumers' expectations. In this regard we would want to improve or maintain levels of security and reliability that are acceptable and affordable to our consumers and satisfies the regulatory quality standard.
- In order to meet our stakeholders' expectations and support our company mission it is important to manage cost and deliver performance through efficiencies and staying within our capital and operational expenditure budgets.
- As a service delivery company we exist to enable economic growth through the provision of electricity delivery and infrastructure services. Managing our assets also means that we will engage with the South Canterbury community to establish, maintain and operate our assets.
- Recognising that we are on a journey towards better alignment with ISO 55000 and improving our AMMAT scores as reported to the Commerce Commission, we must continually improve our asset management capability in order to achieve our company goals and objectives.

2.5. RESPONSIBILITIES FOR ASSET MANAGEMENT

The responsibilities for asset management is set out in Figure 2.3 below.

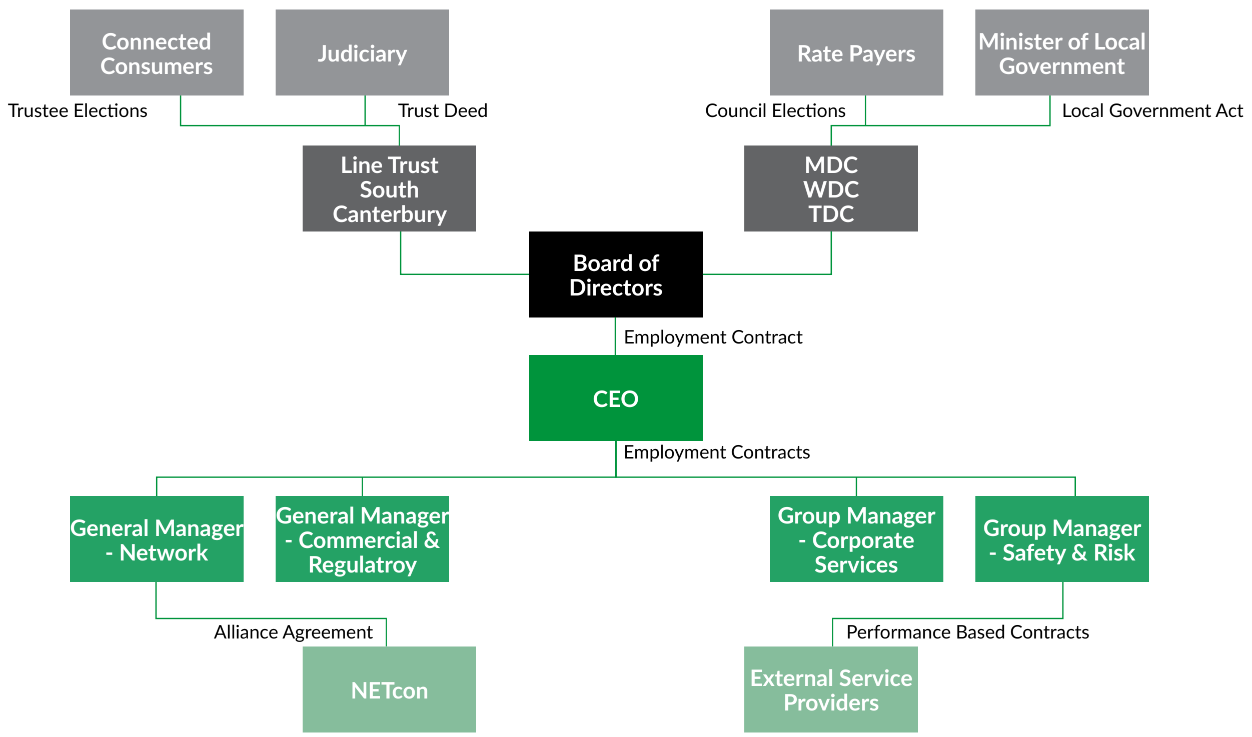

Figure 2.3 Accountability and mechanisms for asset management

2.5.1. OUR BOARD

The Board of Directors governs our business. The Board has delegated overall responsibility for the management of our assets to the CEO. Our directors are accountable to our shareholders through our SCI. We presently have five directors who are appointed as follows:

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

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

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

Board meetings are typically held every two months. Our Board receives a monthly report from management outlining our performance against key indicators, including:

- health and safety
- asset management
- financial performance to budgets for the relevant month and year to date
- operational (corporate)
- corporate
- regulatory
- capital expenditure activities
- quality standards (SAIDI and SAIFI)

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

Projects are approved by the Board of Directors through the AMP and Capital Expenditure approval process.

Our directors are responsible for certifying the AMP. In this regard they also approve the Opex and Capex budgets for the next financial year, while noting, but not approving the forecast expenditure for the remainder of the planning period.

2.5.2. OUR EXECUTIVE MANAGEMENT TEAM

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

2.5.2.1. GROUP SAFETY & RISK

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

2.5.2.2. GROUP CORPORATE SERVICES

The Corporate Services Department manages the financial, human resource, accounting, and ICT system functions.

2.5.2.3. COMMERCIAL & REGULATORY

The Commercial and Regulatory Department ensures that we are aware of our regulatory obligations by various legislation and regulations under which we operate. The department is responsible for billing and registry function, and provides commercial support.

2.5.3. NETWORK DEPARTMENT

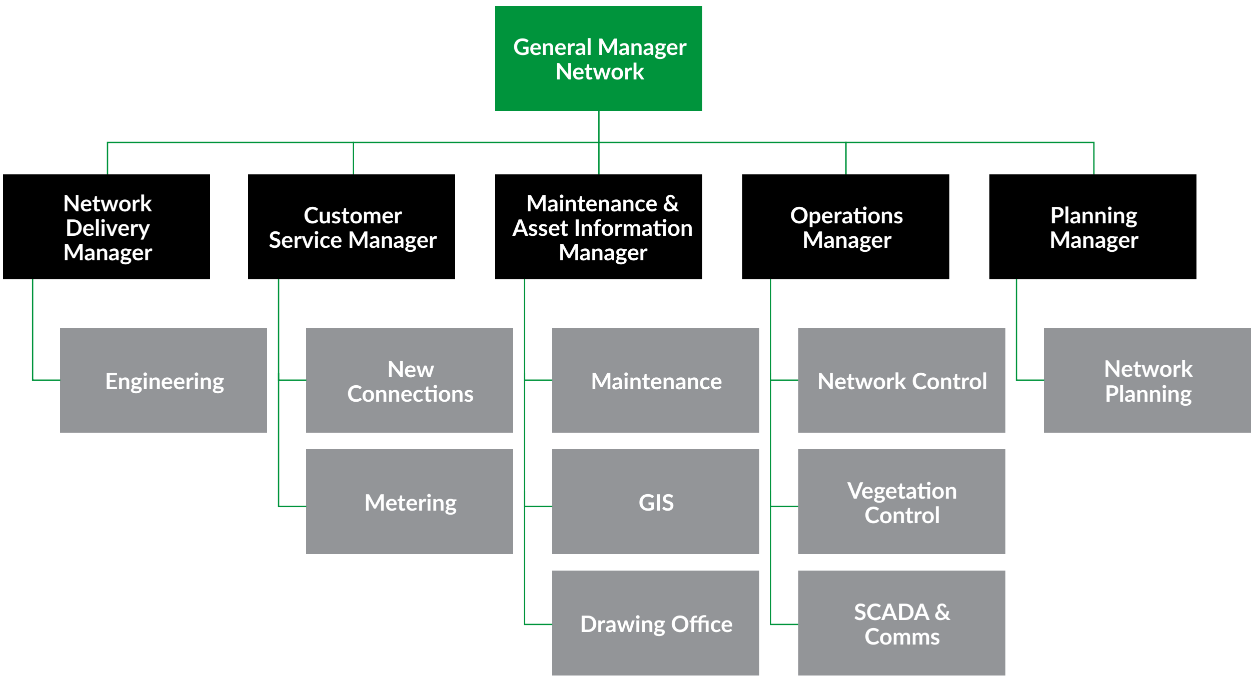

Figure 2.4 Accountabilities for asset management at network level

2.5.3.1 NETWORK PLANNING

The Planning Team is responsible for the strategic planning of the electricity network required to meet security of supply requirements, growth, and other changing needs of our network through detailed load forecasting and network configuration studies.

2.5.3.2 NETWORK DELIVERY

The Network Delivery team is responsible for the design, procurement, installing, and commissioning new capital plant assets, as determined by the Planning team and Customer Service team, to meet the requirements of our growing network.

2.5.3.3 MAINTENANCE & ASSET INFORMATION

The Asset Maintenance and Information team areis responsible for the maintenance of existing electrical assets on our network. The team's responsibility extends to the collection and management of asset condition data. They team are is also the custodians of all asset data and information systems such as GIS, Technology One and drawing management.

2.5.3.4 OPERATIONS

The Operations team is responsible for the real- time operational management of the network assets. They also provide tactical planning, operating, and management of fault response services to ensure high levels of consumer service are maintained. The team is also responsible for:

- all network switching,
- ensuring that work on the network is done safely and with as few, and shortest supply interruptions as possible,
- Vegetation management and our system automation (SCADA – Supervisory Control & Data Acquisition) are two more aspects of operating our assets that this team is responsible for.

2.5.3.5 CUSTOMER SERVICES

The Customer Service team is responsible for processing all new connection and distributed generation applications, as well as technical and administrative metering functions. The team also looks after some retailer service requests such as disconnects, reconnects, site visits, etc. Since we are in the process of moving out of the metering equipment provider space, this workload is reducing.

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3. NETWORK OVERVIEW

3. NETWORK OVERVIEW

This chapter provides an overview of the area that our network covers. Detail of the network configuration and various voltage levels is presented.

3.1 OUR NETWORK AREA

Our network stretches over 10,000 km2, bounded between the Rangitata River in the north and the Waitaki River in the south. To the west, our supply extends to the southern divide as far as Mt Cook Village, while the coast is the natural eastern boundary, as shown in Figure 3.1[5]. The three district councils—MDC, TDC, and WDC—provide infrastructure assets across the area.

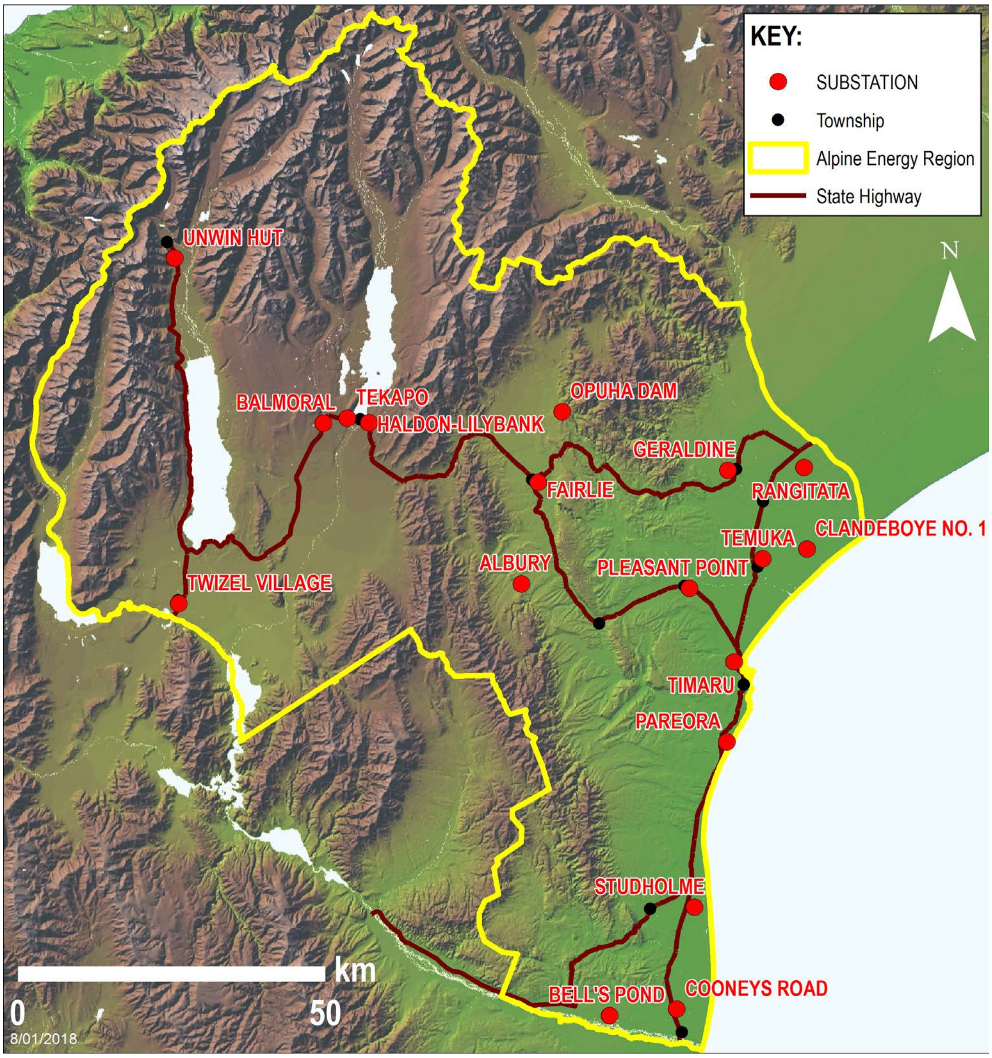


Figure 3.1: Our network area

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

3.2 NETWORK CONFIGURATION

The network is comprised of overhead lines and cables rated at 110 kV (but operated at 33 kV), 33 kV, 22 kV and 11 kV respectively. This rating is used to distinguish between the distinct networks as:

- Subtransmission – 110 kV and 33 kV,
- Distribution – 22 kV and 11 kV,
- Low Voltage (LV) – 230 V single phase and 400 V three phase networks.

Bulk supply is taken from the transmission grid and transferred to lower voltages via power transformers at the grid exit points (GXPs). Electricity then flows through the subtransmission and distribution networks to zone substations and distribution substations where the electricity is converted to LV which is predominantly used in every household as well as most industries.

In some instances we step distribution voltages to subtransmission voltages for distribution to remote zone substations.

Our network connects to the transmission grid at GXPs which are the points of interface between our network and Transpower's network. These GXPs operate at voltages of 110kV, 33kV and 11kV at the seven points of supply described in Section 3.3:

The transmission grid and GXPs supplying our network areis depicted in Figure 3.2 below.

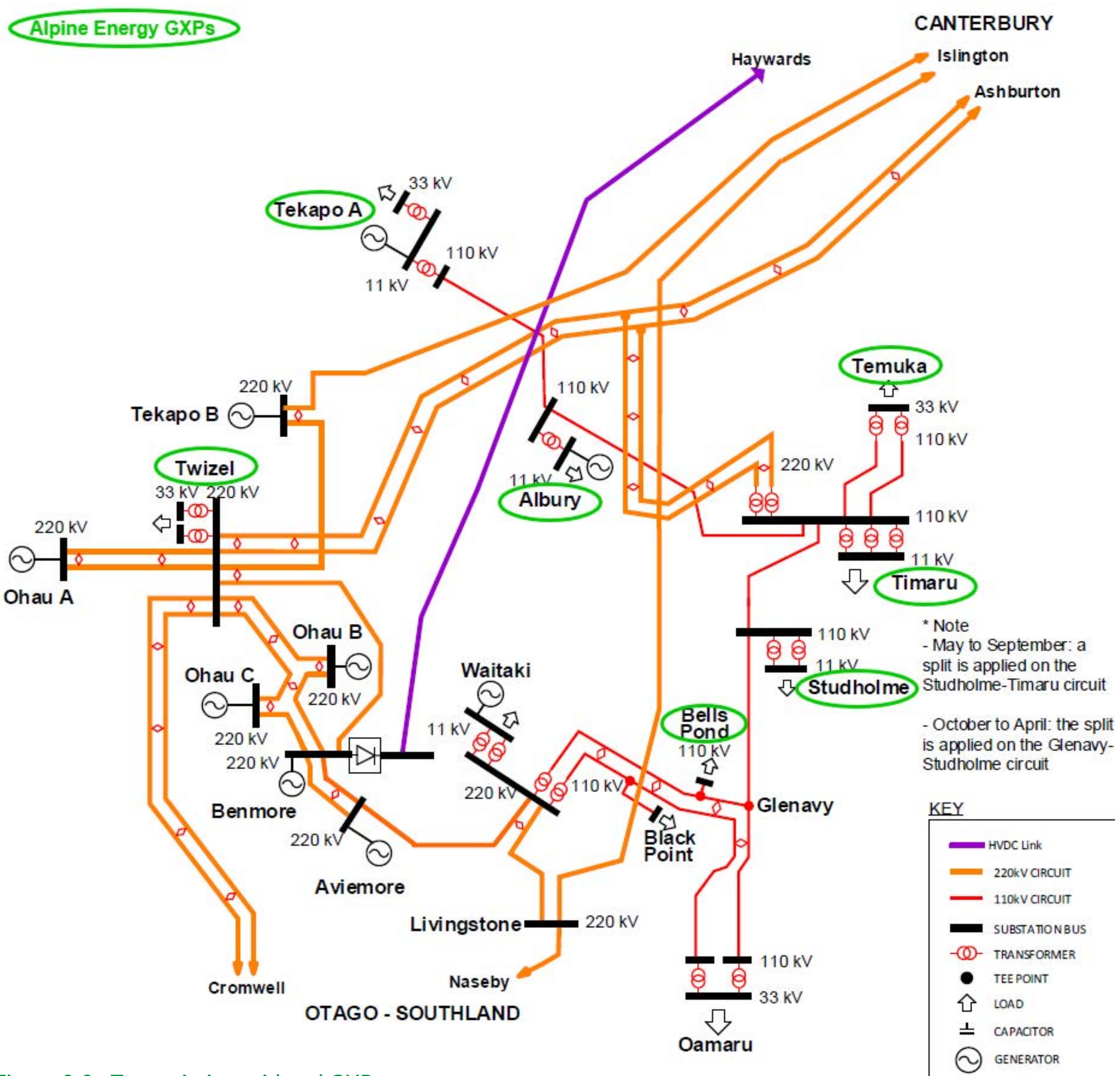


Figure 3.2: Transmission grid and GXPs

The transmission grid conveys electricity from generators throughout New Zealand to distribution networks and large directly connected customers. GXP assets are mostly owned by Transpower, although we do own the transformers, circuit breakers, and protection and control equipment at the Bells Pond GXP.

In general GXPs have secure capacity except in cases where the overall demand or load criticality does not justify the expenditure to have a secure supply. Examples of these are Albury and Tekapo. There are also instances where the load growth mainly due to dairying has resulted in the erosion of any secure capacity at some GXPs. Examples of these are Studholme and Temuka. More details of these GXPs are discussed in section 5.9.

3.3 REGIONAL NETWORKS

Our development as a utility included a number of mergers and acquisitions that have led to a wide range of legacy asset types and architectures. This Differing network designs and equipment requires an asset management approach that accounts for these differences, while seeking to standardise network equipment over time.

This section provides an overview of all our regions. Our seven planning regions form the basis for our Asset Management Planning function. Further details on these areas can be found in section 5.9.

Table 3.1 below presents a quick comparison of infrastructure and demand characteristics for the respective planning areas.

table 3.1 regional network statistics

Measure	Albury	Bells Pond	Studholme	Tekapo	Temuka	Timaru	Twizel
Customer connections	1645	622	3333	893	6861	18185	1550
Overhead circuit length (km)	590	202	552	250	915	944	62
Underground circuit length (km)	26	17	42	58	144	436	36
Zone substations	2	2	1	4	5	3	1
Peak demand(MW)	4.957	11.672	14.794	4.752	54.236	67.416	13.294
Energy con-sumption (GWhr)	13,578 -11,339*	38,163	57,118	19,258	275,777	349,946	14,165

* due to Opuha generation

3.3.1 ALBURY REGION

The Albury region stretches from Maungati in the south past Cave and Albury townships respectively past Fairlie township to Lochaber in the north, Raincliff in the east and Burkes Pass in the west. Apart from the townships all supply is rural and predominantly used for sheep and beef farming as well as some dairying.

The Albury GXP supplies all of this region via two zone substations and four rural feeders, two from Albury GXP and two from Fairlie zone substation with a third supplying the Fairlie township.

The Albury GXP received major upgrade work over the last five years both on our and Transpower's assets. Overall it is in excellent condition with major replacements not expected in the next ten years unless unprecedented load growth in the area requires us to upgrade it to a 33 kV GXP. The supply is considered secure with adequate capacity to meet a small growing demand, as detailed in Section 5.9.1.1

3.3.2 BELLS POND REGION

The Bells Pond area covers our most southern region, just north of the Waitaki River. The main load in this region is irrigation for dairying.

The Oceania Dairy Limited (ODL) dairy factory is located in this region near Glenavy. This dairy factory is the largest load in the region. The Waihao Down irrigation scheme is the second largest load.

The Bells Pond GXP supplies this entire region via two zone substations and six feeders.

Bells Pond was initially constructed in 2009 and the Cooneys Road zone substation in 2013. Overall it is in excellent condition with a second transformer being installed at the time of this publication and no major replacements expected in the near future. The supply is considered secure with adequate capacity to meet the growing demand, as detailed in Section 5.9.2.1.

3.3.3 MACKENZIE BASIN REGION

The Mackenzie region is sparsely populated and has three townships: Twizel, Tekapo and Mt Cook Village. The Twizel and Tekapo townships are experiencing unprecedented growth, mainly due to being popular holiday destinations.

The Twizel GXP and Tekapo A GXPs supply this region via five zone substations at Twizel, Tekapo, Balmoral, Unwin Hut and Lillybank respectively.

The supply in this region was initially constructed to establish Tekapo A power station, Pukaki dam and the Upper Waitaki Power Developments in the late 1950s and from 1968 onwards. Overall it is in average to good condition with some major upgrades and replacements expected in the next five years. The supply is considered secure with adequate capacity to meet the growing demand, as detailed in Sections 5.9.7.1 and 5.9.4.1 respectively.

3.3.4 TEMUKA REGION

The Temuka region has diverse land use. It has two main townships: Temuka and Geraldine, and has several small townships and hut communities. Temuka also includes large areas of irrigation land for dairy, which is mainly concentrated in our most northern area just south of the Rangitata River.

The region is home to the largest dairy factory in the South Island, the Fonterra Clandeboye dairy factory.

The Temuka GXP supplies this entire region via five zone substations, one each at Temuka, Geraldine, Rangitata and two at the Clandeboye dairy factory.

The infrastructure assets at these substations are in a fair to excellent condition with the Rangitata substation only six years old, the Clandeboye substations twenty and thirteen years old respectively. Geraldine substation is the oldest and we are planning to refurbish and upgrade the substation during this planning period. The supply is considered secure at Rangitata, Temuka and Clandeboye with adequate capacity to meet a small growing demand, as detailed in Section 5.9.5.1.

As a result of increasing demand at the Clandeboye milk factory, we are working with Transpower on a project to increase supply capacity of the Temuka GXP in order to maintain a secure supply into the future.

3.3.5 TIMARU REGION

The Timaru region encompases mainly the Timaru City and therefore the majority of the load is residential. The Timaru port with the Washdyke area, constitutes light industrial and commercial load, dominated by coolstores and food processing. There are two freezing works located in this region: the Alliance Group Ltd Smithfield plant and the Silver Fern Farms Pareora plant.

The Timaru GXP supplies all of this region as well as supplying the Transpower 110 kV transmission lines to Temuka and Studholme.

The Timaru GXP has been upgraded in the last six years with a new switchboard and new supply transformers and is in excellent condition. We are planning some replacement expenditure in our zone substation supplying Pareora and Pleasant Point. The distribution feeders are in a good condition and we are in the process of a network upgrade to increase capacity to the Washdyke industrial area. The supply in this area is considered secure with adequate capacity to meet the growing demand, as detailed in Section 5.9.6.2.

3.3.6 WAIMATE REGION

The Waimate region is located south of Timaru with the Waimate town as the centre. Most supply is rural and predominantly used for sheep and beef farming as well as some dairying. The Fonterra Studholme dairy factory is located in this area. A large irrigation scheme is planned for the region.

The Studholme GXP supplies this entire region. Overall it is in good condition with approximately seventy percent of the feeders having been refurbished in the last twenty years. We are planning to refurbish another 157 km of overhead lines in the first two years of the planning period. Major replacements and upgrades could be required if the Hunter Downs Water scheme proceeds or an increase in Fonterra's milk factory energy requirements. The current supply is considered secure but without the capacity to meet any of the above mentioned increased demand requirements. See section 5.9.3.1 for more details.

ASSET MANAGEMENT PLAN // 2018

4. SERVING OUR CUSTOMERS

4. SERVING OUR CUSTOMERS

4.1 OVERVIEW

This chapter details our approach to consumers' requirements for new connections and alterations to existing connections, the service levels that we strive to maintain, and a brief overview of our large consumers. Our performance requirements are also detailed with some historical performance levels.

4.2 GENERAL

Our new connections applications strategy focusses on three main areas namely:

- to be more customer needs focused
- optimise delivery timeframes
- communication with our consumers re connection to our network

We achieve this through clearly identifying the customer's requirements and how we can best accommodate their requirements through both network and non-network technologies, to provide a fit for purpose solution at an acceptable cost.

Solution or project delivery also presents the consumer with a number of options, including:

- design only option - where they can arrange and manage the project themselves using a network approved contractor or,
- a design and construct option - for us using our internal contractor Netcon, or
- a design and construct option - for us using the customer's preferred contractor.

Past communications were very much paper-based with little interaction between the customer and us with no visibility on progress between the customer, their electrician, our contractors and us. We have recently upgraded our website and are evaluating options for full workflow tools and customer job creation/visibility. This will allow all parties to track project progress.

4.3 CONSUMER SERVICE LEVELS

We conduct biennial surveys to establish consumer preferences for quality and security of supply. In 2015, we surveyed 580 of our consumers. We received 275 completed responses on perceptions of reliability, inconvenience, community disruption, and price. The key conclusions were as follows.

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

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

We decided to use the 2015 survey result as we have been receiving consistent responses from our customers for the past years. For the 2016 customer survey we put a new series of questions that are more focused on the customers' ability and willingness to participate in demand management initiatives.

We justify our service levels based on:

- ensuring we design, build, operate and maintain a safe and reliable electricity supply network that meets our stakeholders' expectations
- the preference of the majority of consumers for us to maintain historical levels of supply continuity and restoration for paying about the same price
- the need to prioritise network spend within the constraints of maximum line charge revenue permitted under the default price-quality path
- the physical characteristics and configuration of our network that represent an implicit level of reliability which is costly to alter, but can be altered if a consumer or group of consumers pays for the alteration.
- the diminishing returns of each dollar spent on reliability improvements
- consumer specific request and ability to pay for a particular service level (e.g. uninterruptable supply)
- a third party is imposing a service level or, in some cases, an unrelated condition or restriction that manifests itself as a service level (e.g. a requirement to place all overhead lines underground, or a requirement to maintain clearances).

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

4.4 LARGE CONSUMERS

This section provides details of our largest consumers. We define large consumers as those having an installed capacity of more than 1.5 MVA, or that have a significant impact on network operations or asset management priorities, or consumers with which we have a direct contractual agreement for distribution line services.

4.4.1 DAIRY SECTOR

Dairy farms are spread across our footprint, and are particularly dominant in the Rangitata, Waimate and Glenavy regions. Most dairy farms are part of the Fonterra Co-operative, with the remainder having supply contacts with Oceania Dairy. As a result both Fonterra and Oceania are large key customers of Alpine.

The peak demand in dairy industry occurs in spring and extends into early summer. Load requirements are for processing, on-farm milking, heating and cooling as well as irrigation. Reliability of supply is therefore very important in this industry. As a result most shutdowns for maintenance or network upgrade activities have to be planned for the dairy 'off' season.

At an individual farm level, operations are intensifying due to increasing cooling and holding standards. There is greater use of irrigation and new technologies. There is an increasing requirement for higher reliability of supply and better quality of supply than was previously the case. This growth has consumed most of our spare network capacity, with major new builds in areas where no infrastructure existed. Network planning and operations have become more critical and challenging as a result.

Large Dairy	Installed Capacity
Fonterra – Clandeboye plant	90 MVA
Fonterra – Studholme plant	6.5 MVA
Oceania Dairy – Glenavy plant	15 MVA

4.4.2 IRRIGATION

Irrigation forms a substantial portion of the summer load that we supply across our network. Irrigation developments occur in unison with most dairy farm developments. We currently have only one large backbone irrigation scheme taking a significant supply from our network as detailed in the table below.

Irrigation	Installed Capacity
Waihao Downs Irrigation	4.5 MVA

Irrigation loads occur in the summer months only and the magnitude varies year on year depending on the weather and resulting soil moisture levels.

4.4.3 MEAT WORKS

We are fortunate that in the declining meat works industry to still have two plants operating on our network. Details of these are given below.

Large Meat Processing Consumers	Installed Capacity
Alliance - Smithfield	7.8 MVA
Silver Fern Farms - Pareora	8.6 MVA

The demand in this industry is fairly constant with a slight reduction in processing for the months from June through to October.

4.4.4 INDUSTRIAL / COMMERCIAL SECTOR

Our large industrial and commercial consumers are mainly located in Timaru and more specifically around the port, Redruth and Washdyke areas.

Industrial Consumers	Installed Capacity
Holcim Cement – Timaru Port	6 MVA
McCain Foods - Washdyke	8.2 MVA
South Canterbury By-Products	2 MVA
NZ Insulators	750 kVA
Coolpak Coolstores[6]	3.45 MVA[6]
Polarcold Stores[7]	4.5 MVA[7]
Juice Products	1 MVA
Cavalier Woolscourers	2.5 MVA

[6] Approximately 2 MVA is shared with other consumers

[7] Approximately 1.5 MVA is shared with other consumers

4.5 PERFORMANCE REQUIREMENTS

This chapter details our network performance targets in support of our asset management objectives.

4.5.1. SAFETY AND ENVIRONMENT

Safety is one of the core values and as such we track and report in detail to our board on Health and Safety issues including all incidents on our network. Reporting includes third party, contractor and Alpine Energy staff incidents. Figure 4.1 below summarises the incidents reported and investigated over recent years.

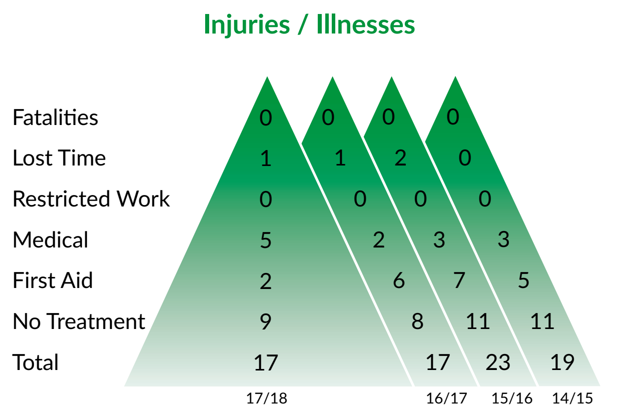


Figure 4.1 Summary of reported and investigated incidents

We also track our performance by lost time incident frequency (LTIFR) which is a normalised index. Performance is measured against the distribution industry average as depicted in Figure 4.2 below. The upward trend towards the end of the period is because we now also record our contractor Netcon's lost time incidents as well as improved and more detailed reporting.

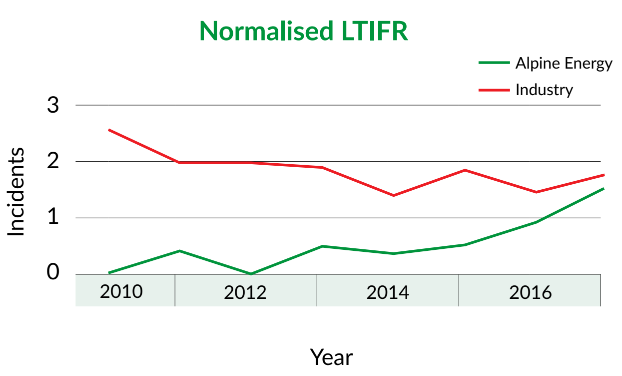


Figure 4.2 Normalised LTIFR

Sulphur hexafluoride is a greenhouse gas, and an excellent electrical insulator used in some of our equipment. The gas is harmful to the environment if it is leaked and hence we maintain a register for the recording of the total volume of gas contained within our equipment. We also used specialised and qualified suppliers to fill new and replenish losses in existing equipment. In that way we do not have to keep any of this gas in store.

4.5.2 LEGISLATIVE COMPLIANCE

It is our target to have full legislative compliance. In order to achieve this target we manage compliance via an external service provider ComplyWith, who maintains a register of all legislation that applies to us as an electrical distribution company. Our executive management team reports quarterly on compliance with all legislation applicable to their area of responsibility.

There are numerous pieces of applicable legislation, with the following being directly relevant to our safety and environmental performance:

- Electricity Act and pursuant Electricity (Safety) Regulations 2010 – applicable to multiple process reviews
- Health and Safety at Work Act 2015 – applicable to internal and contractor processes
- NZECP34 – alignment of maintenance and design requirements for overhead lines and switchgear
- Electricity Industry Participation Code – particularly applicable to distributed generation and protection relays

The quarterly results are reported to our board.

4.5.3 POWER QUALITY

Power quality is made up of components, most of them technical, such as voltage regulation, frequency, unbalance, harmonics, flicker, voltage dips/sags/surges to name the most common. Only two of these parameters are currently regulated namely frequency and voltage regulation.

With the program to roll out smart meters across our network we will be in a much better position to pro-actively action power quality issues related to voltage regulation. Access to the smart meter information is possible on meter by meter basis. The ownership of the data on the meter is a contentious issue. Our aim is to report on voltage regulation excursions once we have sufficient numbers of meters installed and data manipulation is improved.

More complicated power quality issues are handled on a case-by-case basis and involves collaboration with the affected party. This often involves detailed engineering modelling and specialised measurements to be taken to appropriately deal with the issues.

4.5.4 RELIABILITY

The reliability of our supply is measured at, and targets are set at a network level. Reliability is one of the regulator's quality criteria and is measured through SAIDI and SAIFI indices as defined below.

SAIDI and SAIFI

SAIDI: is a measure of the average duration that a consumer is without power in any one year as a result of both planned outages and emergency outages on the network.

SAIFI: is a measure of the number of times (frequency) that any individual consumer will be without power in a one year period.

It is important to note that these are aggregate measures and that individual consumers could have a different experience.

Our historical performance against these two measures are given in the figures below.

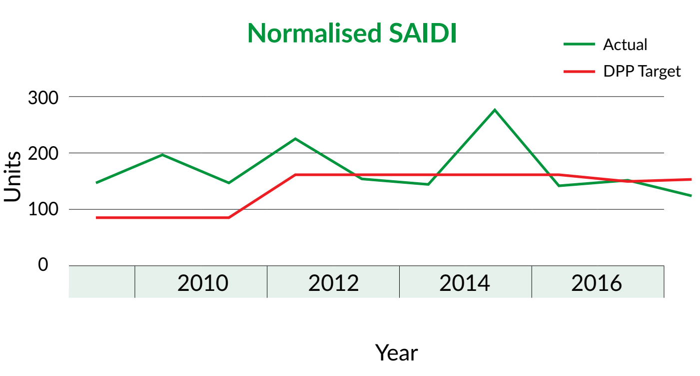


Figure 4.3 Historical normalised SAIDI performance

The breach of the target in 2014 was mainly due to the severe wind storm in October 2013 when multiple outages were experienced due to blown over and broken trees in the power lines.

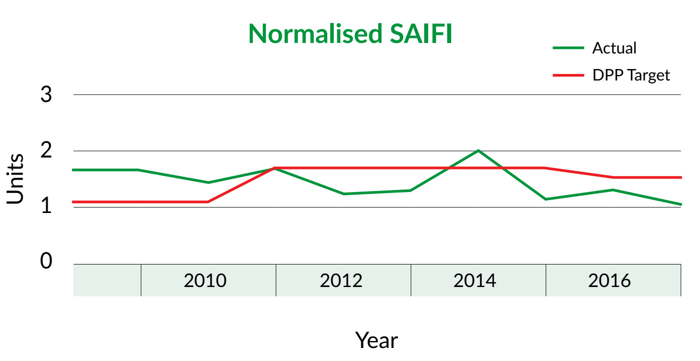


Figure 4.4 Historical normalised SAIFI performance

4.5.5 SECURITY STANDARDS

An aspect of our performance requirements is to be able to supply power with an appropriate level of security. Our definition of the various levels of security is detailed in the table below. This performance requirement also serves as a trigger for investment on our network.

Table 4.1 Security of supply classification

Security level	Description
N	N is the security level at which any outage will cause load to be lost and is often found where there is only one supply circuit or transformer that provides supply. Meaning the lost load will be restored in the time it takes to repair the fault.
N-0.5	N-0.5 is the security level at which an outage will result in some load to being able to be restored after ties have been made to other substations. Meaning the lost load will be partially restored (in this example 50%) after switching (reconfiguration of the network) and the remainder of the lost load will be restored in repair time.
N-1	N-1 is the security level that ensures supply after a single contingency event. Meaning no load will be lost due to a single failure.
N-2	N-2 is the security level that ensures supply after two contingency events. Meaning no load will be lost due to consecutive failures on two separate circuits.

Security levels for the different areas or types of consumers on our network are detailed in section 5.9.

ASSET MANAGEMENT PLAN // 2018

5. NETWORK PLANNING

5.0 NETWORK PLANNING

5.1 OVERVIEW

This chapter describes our processes for network planning and the criteria used to make decisions on network investments. Planning is governed through our AMF, starting with the asset management policy at the top. (refer to Section 2.4).

The main inputs to our network planning are:

- levels of service and security standards (section 4),
- demand forecasts,
- and our asset replacement program.

To produce the network development plans, we use the above inputs to establish network investment projects. Each network project is subject to an options analysis, which includes non-network solutions and new technology solution. The size of the expenditure and the criticality of the project determine the amount of detail in the options analysis.

Each project is ranked for priority based on our Risk Management Policy. More information on this can be found in Appendix A.3.

Our network planning is done over seven regions, which line up with the Transpower GXPs. The regions are Albury, Bells Pond, Studholme (Waimate), Tekapo, Temuka, Timaru and Twizel.

5.2 DEMAND FORECASTING

5.2.1 DEMAND DRIVERS

The main drivers influencing electricity demand in our area relate to weather and economic activity.

Economic activity in our area of operation strongly influences the configuration of our network. In addition our performance targets and service delivery dictates decisions on network configuration and any anticipated changes.

There has been significant growth in dairy farming and processing, bringing an increased demand from irrigation, along with the need to supply the Oceania Dairy Limited (ODL) dairy factory near Glenavy and the Fonterra dairy plants at Studholme and Clandeboye. Other large industrial consumers, such as the Alliance Smithfield and Silver Fern meat processing plants, impact on network configuration and augmentation. Overall, the viability of arable farming and the availability of water have a significant impact on the local economy and subsequently also on the design and configuration of our network.

Irrigation load is the main cause of summer peak loading at all the GXPs except Timaru, Tekapo, and Twizel although the increase in irrigation is tempered by local environmental restrictions on water use and nitrogen discharge.

Winter peak loading occurs mainly at Timaru and Tekapo GXPs, although other areas, like Fairlie and Geraldine, also have significant demand for load during the winter months.

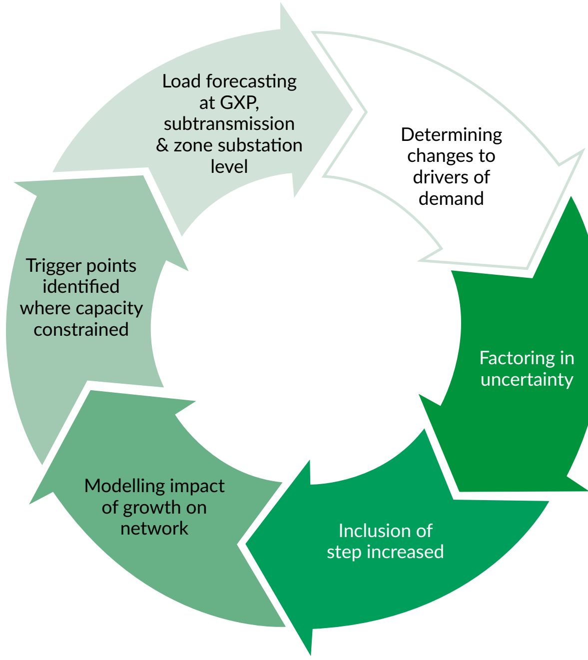


Figure 5.1 Demand forecasting process

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

The load forecast at the GXPs and zone substations is established through the use of historical demand data extracted from our SCADA system and applying the linear regression method. In addition to this method step increases are then added to the forecast.

When we establish the forecast system growth, we only include those builds which have a high level of certainty of proceeding, where capital contributions are paid or are expected to be paid. This is due to the size of the intended builds which involve significant investment on our part.

The results of this process are detailed in the forecast of the regional plans in Section 5.9 below.

5.2.2. DEMAND FORECASTING

The total energy consumed in 2016/17 was 836 GWh. Annually, energy consumed varies from year to year depending on wet or dry irrigation seasons, and severe or mild winters.

The coincident peak demand (CPD) is presently 137 MW[8]. Growth in CPD has been approximately 2.49% per year over the last 18 years.

Figure 5.2 shows the overall network demand for the last 20 years and the projected change for the next ten years.

The capacity of our distribution network is determined by the lowest rated equipment at a GXP or a zone substation. For this reason the lowest rated equipment has been plotted on the demand forecast plots. When demand forecast exceeds this equipment rating, this is a trigger point for a network investment.

[8]As reported in our 2017 information disclosures

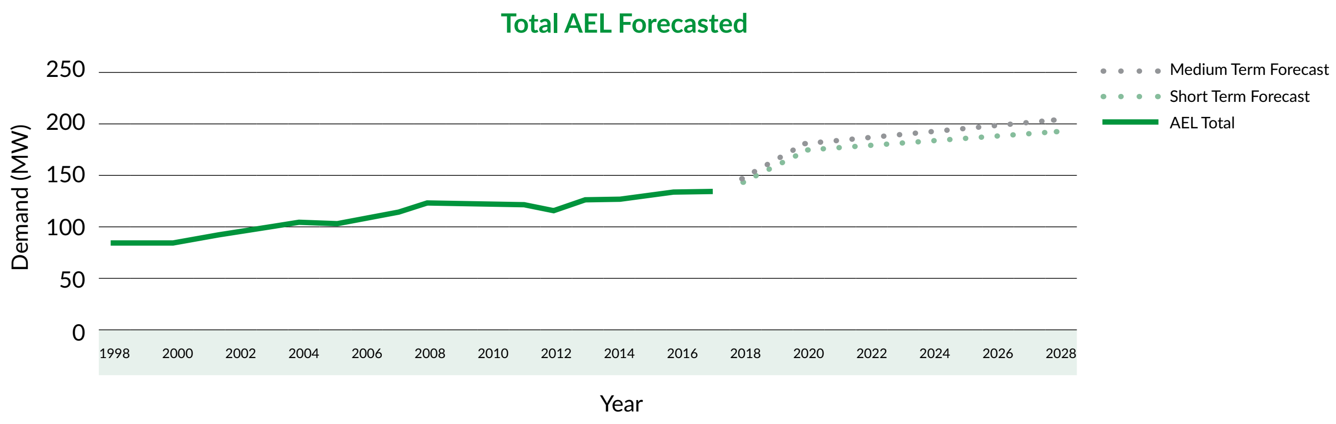


Figure 5.2 Total peak demand forecast

Our distribution network is supplied from seven GXPs. The land use and business activities in each region are very different. Therefore the CPD is not a good measure for network development and hence we do our forecasting and network planning by regions.

5.3 INVESTMENT DECISION PROCESS

As mentioned above, various inputs feed into our regional network development plans. These inputs are shown in Figure 5.3.

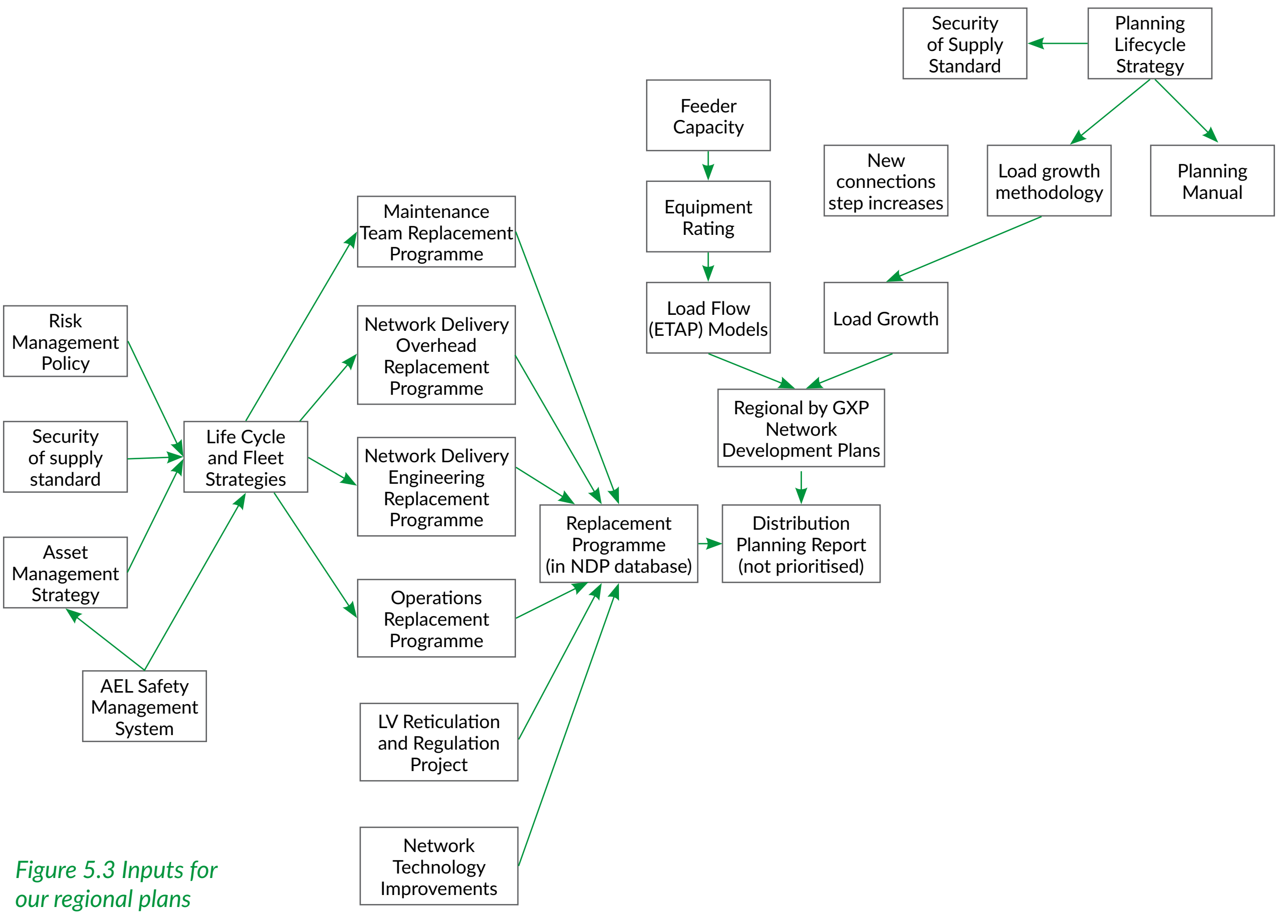


Figure 5.3 Inputs for our regional plans

All network investments are divided in the following types:

- Consumer connections
- System Growth
- Asset replacement and renewal
- Asset relocations
- Reliability, safety and environment
    - Quality of supply
    - Legislative and regulatory
    - Other reliability, safety and environment
- Replacements

These categories align with the Commerce Commission's EDB information disclosure requirements.

We maintain a database of opportunities and network projects. The database contains all the proposed network projects and allows us to rank these projects based on a set of criteria as detailed in Table 5.1.

After prioritisation of all projects, the works program for the next financial year is extracted from the database and submitted to the Board for approval.

5.3.1. INVESTMENT TRIGGERS

There are several investment triggers for network investment projects:

- Health and Safety (public and staff)
- Not meeting stakeholder (consumers) expectations
- Non-compliance with our Security of Supply Standard
- Exceeding equipment ratings
- Insufficient quality of supply (voltage levels, harmonics, flicker)
- Replacement and renewal
- Environmental

Each of these triggers are discussed in more detail in sections 5.4 to 5.8.

Table 5.1 Criteria for prioritising projects

Criteria for assessing options	Description
Safety	Projects that require execution to improve safety and/or remove hazards. Criteria include: public safety, workplace safety, and network operating safety.
Risk reduction	Projects that allow the risk to the company to be reduced in accordance with our Risk management Policy. This includes health & safety, reputation (branding), environmental, compliance and financial impact.
Reliability of supply	Projects that improve network resilience in the face of faults, undesirable events, and general use. Criteria include: improve network condition, interoperability, adaptability, flexibility, ease of use, and maintainability.
Security of Supply	Projects that ensure our network assets comply with our Security of Supply standard (currently we use the EEA Guide for Security of Supply) and improve the capacity of the network to meet stakeholders expectations.
Efficiency	Projects that improve the performance and costs of the network to meet stakeholder needs. Criteria include: network operating performance, organisation of network assets, improvement of network design, and a reduction in maintenance and operating time through selection of maintenance-free equipment with minimum operation requirements.
Economy	Projects that produce the best return in terms of network improvement for funds expended and provide a reduction in life cycle costs through selection of "maintenance-free" equipment with lowest inspection and operation overheads.
Ease of project implementation	Projects that are the easiest to implement with respect to multiple contractors and stakeholders, high internal resources commitment, implementation time and high risk of exceeding planned SAIDI.

5.3.2. OPTIONS ANALYSIS

Once a trigger point has been identified, we define the risks from the issue, and considering options to reduce the risk to an acceptable limit. An example is where we are no longer complying with our security of supply standard due to load growth. Table 5.2 described various options considered when capacity is exceeded or expected to be exceeded. The options are listed in order of preference.

Table 5.2 Options considered for capacity constraints

Option	Description of option	Example of a possible option
Do nothing	Simply accept that one or more parameters have exceeded a trigger point. In reality, the do nothing option would only be adopted if the benefit-cost ratio of all other reasonable options were unacceptably low and if option does not constitute an unacceptable risk as per our Risk Management Policy.	The voltage at the far end of an 11 kV overhead line falls below the threshold for a few days per year—the benefits (including avoiding the consequences) of correcting such a constraint are simply too low.
Operational activities	Switching the distribution network to shift load from heavily-loaded to lightly-loaded feeders to avoid new investment, or introducing a voltage regulator or capacitor bank to mitigate a voltage problem. A downside is that switching may increase line losses and reduce security of supply. This a typical example of an non-asset solution.	
Influence consumers	To alter consumer consumption patterns so that assets perform at levels below the trigger points through tariff structures and/or demand side management.	Shift demand to different time zones, negotiate interruptible tariffs with certain consumers so that overloaded assets can be relieved, or assist a consumer to adopt a substitute energy source to avoid new capacity.
Construct distributed generation	An adjacent asset's performance is restored to a level below the trigger points. Distributed generation would be particularly useful where additional capacity could eventually be stranded or where primary energy is underutilised.	Water being released from a dam that could be used in a hydro generator, or install a high pressure boiler for an electricity turbine, then use medium pressure outflow for industry.
Modify an asset	Essentially a sub-set of retrofitting, that generally involves less expenditure. Modifying an asset is more suited to larger classes of assets such as 33/11 kV transformers.	By adding forced cooling to a power transformer or considering cyclic overload parameters.
Retrofitting	Retrofitting equipment with improved technology devices that can exploit the features of existing assets.	Installing radios and actuators on reclosers and regulators for automation so that they can be remotely controlled and operated.
Install new assets	A greater capacity will increase the assets trigger point to a level at which it is not exceeded.	Replacing a 200 kVA distribution transformer with a 300 kVA transformer or replacing light conductor with a larger conductor. We research likely ground conditions to rate underground cables as high as possible to allow maximum power flow.

The preferred option is chosen during planning sessions with the network managers based on risk management criteria.

We have implemented a software-based decision making tool that will assess and balance competing demands for growth, safety, and financial return, to identify the best options. Combined with the experience and knowledge of our engineers the tool will greatly enhance the network planning process. Gathering and populating the tool with relevant data is our next focus.

5.3.3. NON-NETWORK SOLUTIONS

In addition to network solutions, non-network solutions are considered. These solutions may be considered as an alternative to network solutions, or in conjunction with network solutions.

Examples of non-network solutions are:

- Demand side management.
- Distributed generation, both renewable (PV, Wind, hydro, biomass) and non-renewable (diesel generation)
- Energy storage (batteries, heat or water storage)

The roll out of smart meters may make these solutions more practical and effective.

5.3.4. DISTRIBUTION PLANNING

We need to ensure that the capacity of our network and the voltage profiles at each point of supply are adequate to meet existing and future consumer load.

We do this by several approaches:

- Proactively analysing the performance of our 33 kV subtransmission and 11 kV distribution feeders using computer modelling[9]
- Consumer inquiries for new or increased capacity engineering investigations
- Consumer feedback and complaints investigations
- Specified studies of operational issues, for example exploring new back feed options.

These analysis and investigations typically result in network investments like feeder voltage support (improved zone substation voltage control, regulators or capacitor banks), distribution transformer upgrades, cable and line upgrades, new feeders, etc.

5.3.5. DISTRIBUTED GENERATION

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

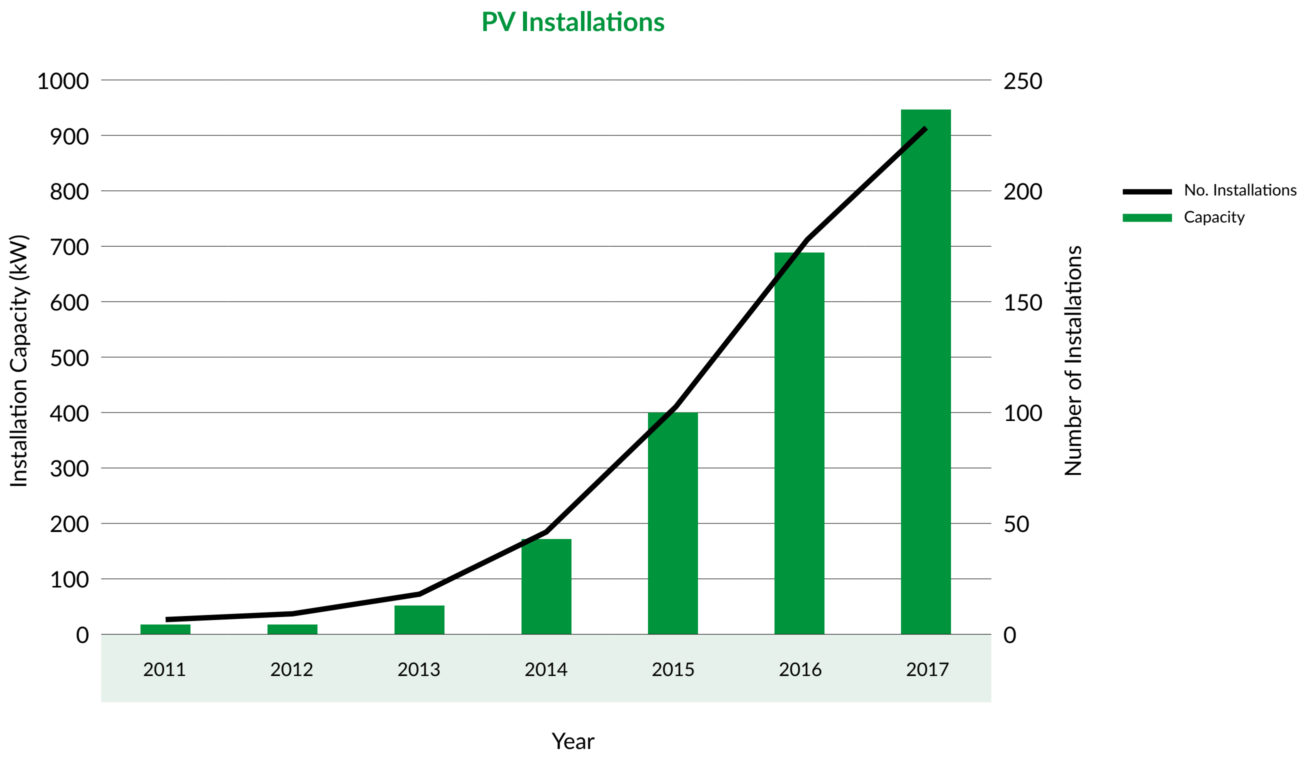


Figure 5.4 PV installations

[9] Using ETAP power system analysis www.etap.com

Those wishing to connect distributed generation on our network must ensure that a contractual agreement with a suitable party is in place to consume all injected energy—generators will not be permitted to lose energy in the network. Other key elements of our distributed generation policy include:

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

We have developed procedures with a simple series of steps that owners of distributed generation can follow to have small scale (less than 10 kW) and large scale (larger than 10 kW) distributed generation connected to our network. We adhere to the prescribed charges in Part 6 of the Electricity Industry Participation Code 2010. Distributed generation that requires a new connection to the network is charged a standard connection fee with adherence with Part 6 of the Electricity Industry Participation Code 2010. We may also recover the costs to reinforce the network from the distributed generator back to the next transformation point.

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

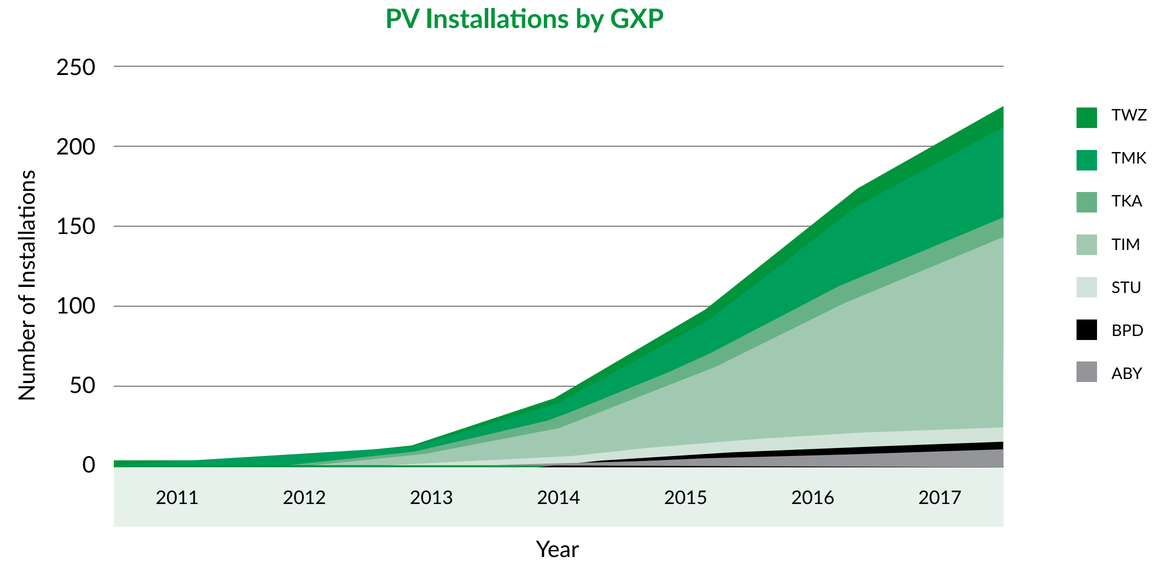


Figure 5.5 PV installations by GXP

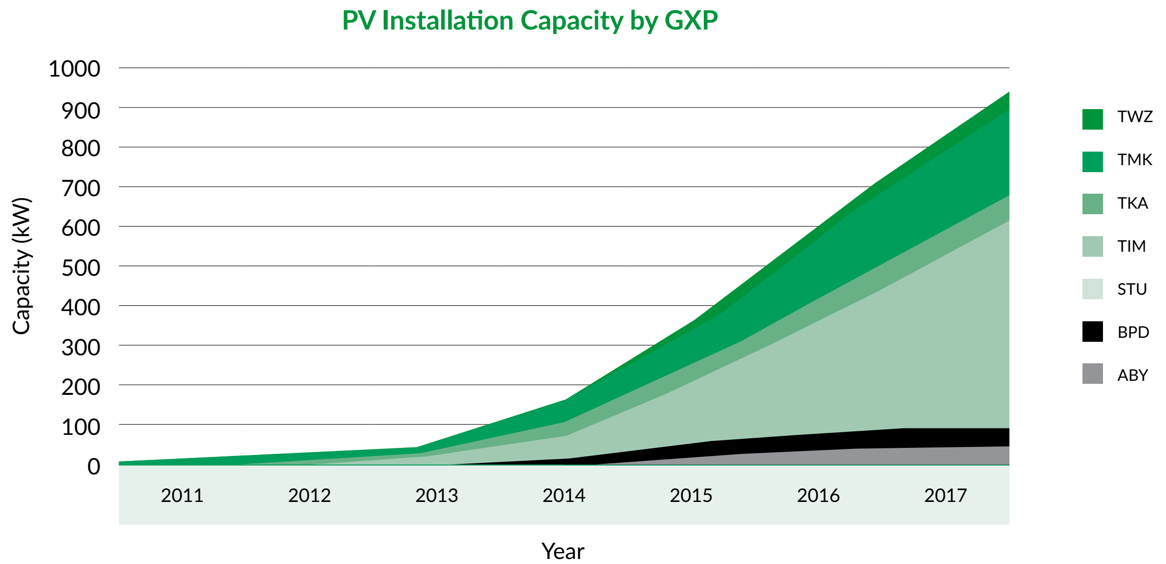


Figure 5.6 PV installation capacity by GXP

5.4 SYSTEM GROWTH & SECURITY SYSTEM GROWTH & SECURITY

5.4.1 CONSUMER EXPECTATION

In our planning we take into account our consumer's expectations. If these expectations change they may trigger a network investment. The sources of consumer expectations are:

- Requests for new or additional load by consumers.
- General consumers. This includes all residential and commercial consumers. These expectations are established by means of consumer surveys. You can find more detail on the survey data in Section 4.3.
- Requirements in use of system agreements with energy traders operating on our network. There are 22 Energy traders operating on our network.
- Specific contracts with consumers (for example Fonterra, Oceania Dairy Limited and Opuha Water Limited).

5.4.2 SECURITY OF SUPPLY STANDARD

A key component of security of supply is the level of redundancy that enables supply to be restored while a faulty component is repaired or replaced. Definitions of security of supply can be found in Table 4.1. Typical approaches to providing security of supply at a zone substation include the following:

- Provision of an alternative sub-transmission circuit into the substation, preferably separated from the principal supply by a 33 kV bus-tie.
- Provision of twin transformers with emergency rating, allowing one to cover the load of the other if it trips or faults.
- Provision of back-feed on the 11 kV from adjacent substations where sufficient 11 kV capacity and interconnection exists.
- Use of local generation (e.g. Opuha dam) or portable diesel generator set(s).
- Use of interruptible load (e.g. water heating or irrigation) to reduce overall load.

The difficulty with security is that it involves a level of investment beyond what is needed to meet demand. This comes at a cost.

We need to be careful that load growth and any step increases do not erode away security headroom.

We have adopted the EEA Guidelines for Security of Supply in our network, meaning that, on the subtransmission system, we will strive to achieve a N-1 security level.

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

The present levels of security of supply are listed in the regional plans in Section 5.9.

We have a project underway to review our security of supply standard to ensure alignment with stakeholder expectation, affordability and consideration of new technologies (for example battery storage).

[10]Such an arrangement requires that, firstly, the adjacent zone substations have spare capacity and, secondly, that the prevailing topography enables interconnection.

5.5. REPLACEMENT & RENEWALS

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

Overhead lines are routinely inspected and condition assessed as detailed in section 6.2.6 and the remaining strength of the support poles are assessed to determine end of life. Substation and plant inspections are undertaken either by the maintenance contractor as part of the routine maintenance programme or as part of a one –off condition assessment inspection by a technical expert. The information from these inspections is collated, reviewed, assessed, and used to inform our asset management decisions.

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

All replacement and renewal projects are submitted to planning to check alignment with system growth projects (to ensure the existing rating is sufficient for the planning period). After this check the replacement and renewal projects are prioritised together with all other network projects.

5.6. RELIABILITY, QUALITY, SAFETY & ENVIRONMENT

5.6.1 SAFETY

Safety always is one of our values.

In our asset management activities we ensure our network is safe for public, contractors and staff by means of our Safety Management and Public Safety Management systems. More details can be found in appendix A.4.

We are developing our own Safety in Design framework with the assistance of the Safety in Design guide from the EEA.

5.6.2 QUALITY OF SUPPLY

VOLTAGE REGULATION

Electricity regulations require us to control voltage at the Point of Supply to a consumer within ±6% of the standard voltage of 230/400 V, except for momentary fluctuations (voltage dips). In order to comply, we take care to select the appropriate capacity when choosing equipment that may influence voltage regulation. Equipment with influence on voltage control includes: power transformers fitted with on load tap changers (OLTCs), voltage regulators, capacitor banks, distribution transformers fitted with off circuit tap changers (OCTCs) switches, cables and overhead conductors sizing.

Increasing demand may cause voltages to be outside the regulatory requirements. Compliance with the regulations will trigger network investment projects, for example a line upgrade.

HARMONICS

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

- the New Zealand Electrical Code of Practice for Harmonic Levels, NZECP 36:1993, and
- the EEA Power Quality (PQ) guidelines 2013.

POWER FACTOR

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

5.6.3 RELIABILITY

We review faults on our network and investigate the causes to determine how interruptions can be reduced or avoided. Our reliability is measured using the system average incident duration index (SAIDI) and system average incident frequency index (SAIFI) in accordance with the Commerce Commission's Information Disclosure Determination 2012. Refer to section 4.5.4 for more detail.

Our consumers have voiced a preference to receive 'about the same' reliability in return for paying' about the same' line charges (see section 4.3).

There is no mandate to improve reliability simply because it can be improved, but there is a mandate to maintain supply.

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

- tree regrowth
- declining asset condition, especially in coastal marine areas
- extensions to the network that increase its exposure to trees and weather
- growing consumer numbers that increase lost consumer-minutes (SAIDI) for a fault
- installation of requested asset alterations that increase reliability risk
- increase in frequency and magnitude of extreme weather conditions due to climate change.

Reliability enhancement programme includes the following steps:

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

5.6.4 ENVIRONMENT

It is our obligation to conduct all activities considering the environmental impact. Our Environmental Policy gives effect to this obligation.

We will:

- integrate environmental considerations into all aspects of our business activities
- take all practical steps to avoid, remedy or mitigate any adverse environmental impact resulting from our activities, assets and services on the environment
- undertake continuous improvement in sustainability, and environmental management practices and performance
- enhance environmental awareness and responsibility by employees, contractors, and suppliers
- promote the responsible and efficient use of electricity, materials, and natural resources
- sustain a high level of environmental performance in addition to complying with all relevant legislation
- treat environmental emissions or waste in accordance with the applicable laws and regulations

For this reason we also consider environmental issues in our Risk Management policy and our prioritisation of network investment projects.

5.7. ASSET RELOCATIONS

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

The cost of underground versus overhead depends on several factors including cost of labour, materials, topography, and terrain.

We still have a significant amount of overhead LV reticulation in the town and country areas. Following the damage to underground cables during the Canterbury earthquakes, we decided to cease our programme of undergrounding existing overhead infrastructure and to consider undergrounding on a case-by-case basis. Undergrounding of existing overhead infrastructure is only done for engineering or safety reasons.

5.8. CUSTOMER CONNECTIONS

Every year we have hundreds of new connections applications ranging from the smaller typical house connection through to the commercial/agriculture connections and large industrial connections. This is all market driven work and all at the request of a third party. We also do a large number of alterations at existing sites which is mostly in the irrigation, dairy and industrial areas. The process for a new connection or alteration is documented in the New Connections and Extensions Policy which is available on our website. Most enquiries come in through the network applications process from electricians on behalf of the land owners, or developers/ civil surveyors. All costs associated with the additional requirements to extend the network as part of the customer connection is funded by the requesting party as a capital contribution.

We have recently seen a large increase in residential subdivisions and have had more large scale subdivisions than previous years. This has been most notable in the Timaru, Tekapo and Twizel areas with some subdivisions now completed and more scheduled to start in 2018. Small scale subdivisions where the land owners subdivide an existing property into one or two smaller sections has continued in the Temuka, Geraldine, Waimate and Timaru areas.

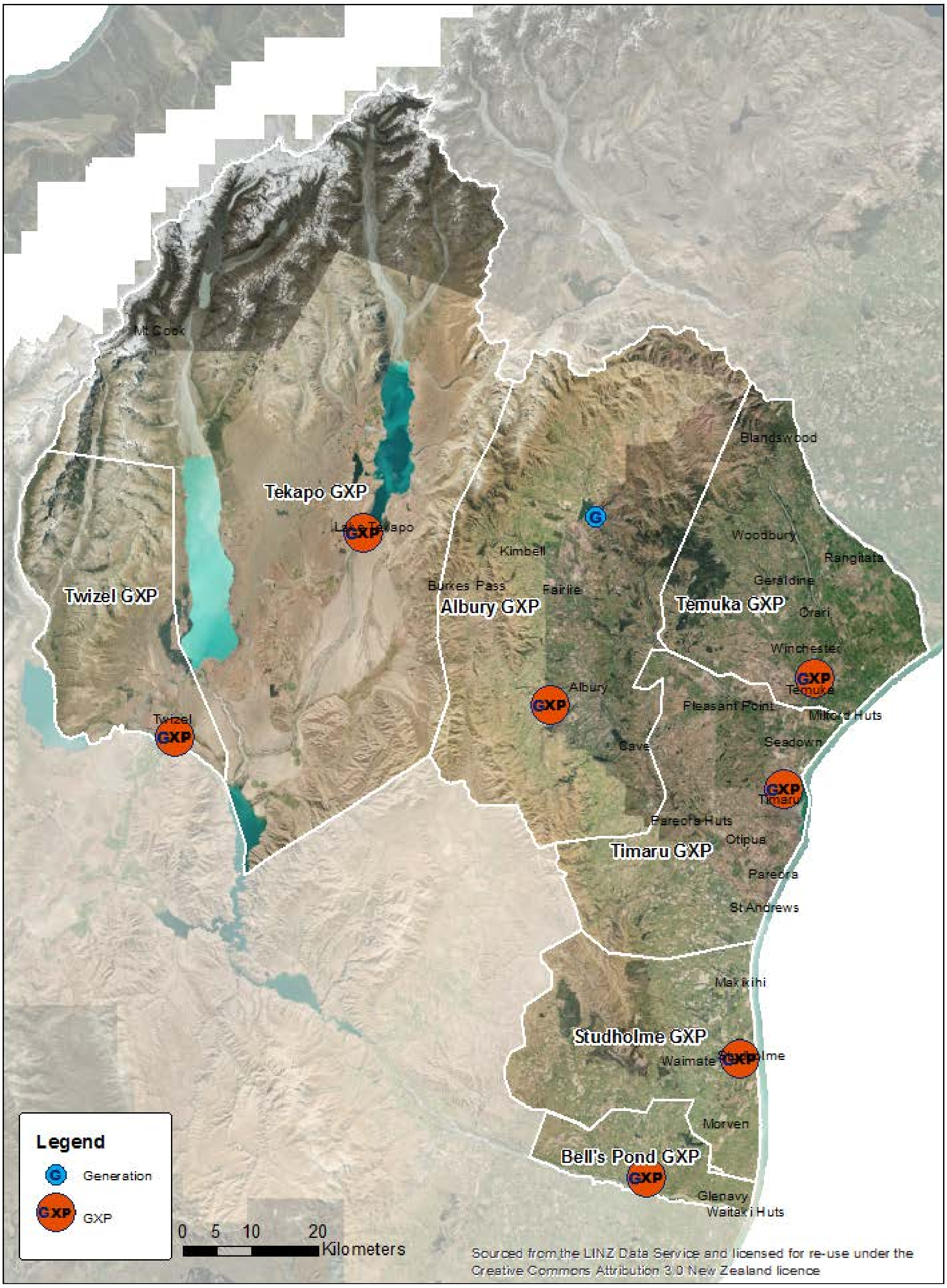
Industrial connections have also continued with current project work at the Fonterra Clandeboye site underway and additional work in the design phase. The Timaru port area has continued to expand with increased ship movements in and out of the Port, and additional container storage including planned expansion for reefer containers at multiple sites in the port area. Timaru Oil Services are also in the process of building a 44 million litre bulk fuel terminal with a new fuel line to the wharf area.

5.9. REGIONAL PLANS

This section summarises the network Development Plans for each of our seven planning regions (see Figure 3.1). Each planning region is supplied by its own GXP from Transpower (refer to Figure 3.2.

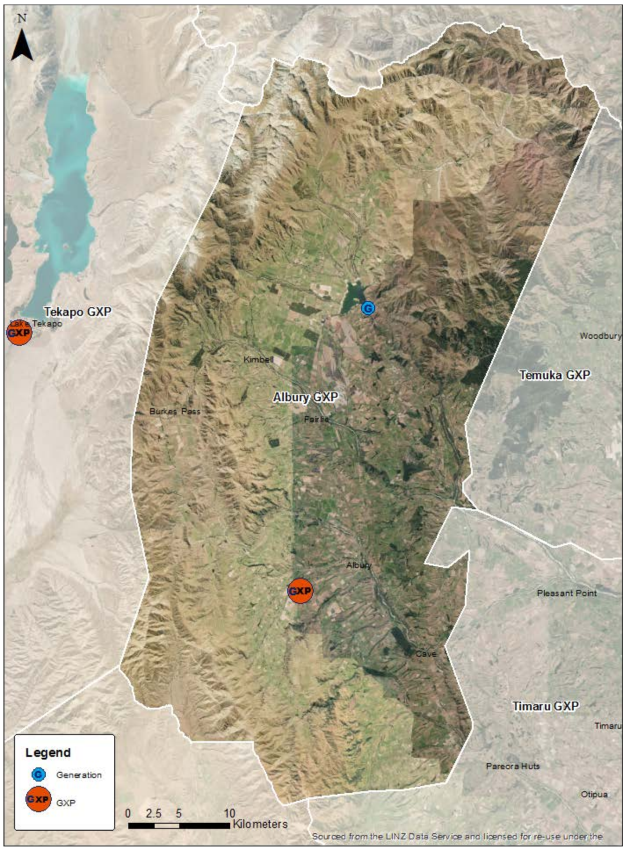
We have developed Network Development Plans (NDPs) for each region.

ALPINE ENERGY GXP GEOGRAPHIC AREAS



Appendix A.5 gives more detail on demand forecasts for each region.

ALBURY GXP GEOGRAPHIC AREA



OVERVIEW

The Albury region is mainly rural with the main farming activity being sheep and beef farming. There are two main townships, Albury and Fairlie; Fairlie being the largest.

Fairlie has a commercial area supplying services to the surrounding farms, but it also hosts for tourist travel from Christchurch to Tekapo and on to Queenstown.

Lake Opuha is located near Fairlie supplying the Opuha irrigation scheme. The scheme also owns and operates a 7 MW hydro power scheme embedded in our network (at 33 kV).

NETWORK CONFIGURATION

Appendix A.6.1 described the network configuration and shows the schematic diagram of the Albury GXP and zone substations.

5.9.1.1. DEMAND FORECAST

Demand forecasts for the Albury GXP, and regional zone substations are shown below with further details provided in Appendix A.5.

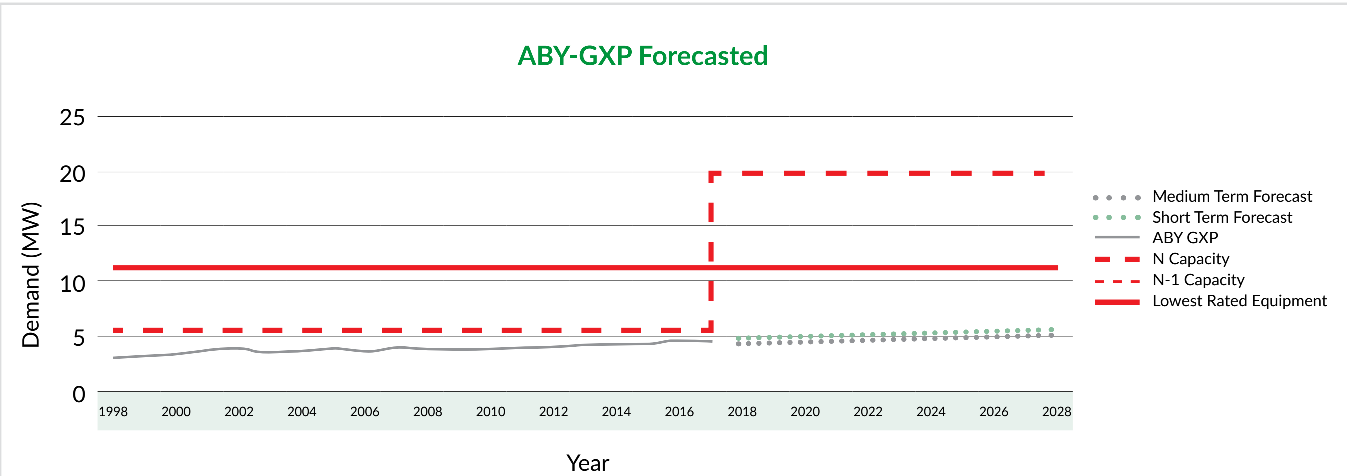


Figure 5.7 Albury GXP demand forecast

Table 5.3. Albury region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)
Albury GXP *	20	-	11.30	4.51	4.57	4.63	4.69
Albury zone substation	7.50	-	7.83	4.74	4.80	4.87	4.93
Fairlie zone substation	6.25	-	5.24	2.67	2.71	2.74	2.78

*Transpower equipment (refer to www.transpower.co.nz).

The demand is growing slowly and there are presently no significant step increases from new connections to the network.

5.9.1.2. SECURITY OF SUPPLY

Table 5.4 Albury and Fairlie security of supply

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
Albury Rural	N-0.5	N	Limited fault back up from adjacent feeders from Fairlie, Pleasant Point and Temuka. Encourages consumers to self-manage their risk mitigation for outages for example, during a civil defence emergency.
Fairlie	N	N	Limited fault backup. Possibility of some supply from Albury and Geraldine or islanding Fairlie onto our mobile generator (limited capacity) or Opuha. Opuha requires negotiation with generation management, careful islanding, does not have black start capabilities, and does have speed control issues due to the flywheel of the generator being too small. Encourages consumers to self-manage their risk mitigation for outages for example, during a civil defence emergency.

5.9.1.3. EXISTING & FORECAST CONSTRAINTS

Transpower installed a new 110/11 kV transformer in 2017. The new transformer's rating is based on the smallest economic size for purchase being 20 MVA for a 110 kV primary rating. There is, however, a capacity limitation (due to Transpower protection equipment rating) that makes only 11.3°MVA available to us[11]. Despite the limitation, this will still provide ample capacity for the planning period and beyond. The new transformer also restores this GXP with a functional tap changer. This will regulate the 11 kV voltages, aiding available capacity in the 11 kV feeders. The transformer's secondary connection is arranged so it can be reconnected for use at 33 kV in the future.

The Albury rural area has limited back up from adjacent 11 kV distribution feeders from Fairlie, Pleasant Point and Temuka. This is mainly due to the distances involved (voltage constraint).

The following backup options are currently present for the Fairlie township and rural areas:

- connecting our mobile generator at Fairlie zone substation;
- limited supply from adjacent 11 kV feeders from Albury and Geraldine;
- supply from Opuha power station. This option is limited due to no black starting capability and no accurate speed control. Approval by the generator operator (Trustpower) is required. Therefore the Opuha power station is not considered in any security of supply considerations.

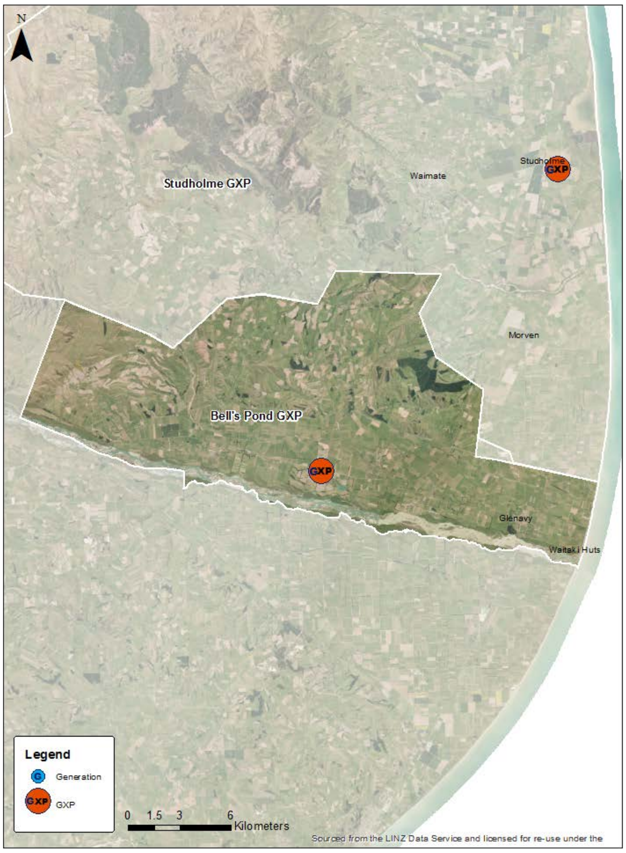
5.9.1.4. MAJOR GROWTH AND SECURITY PROJECTS

There are presently no major growth projects or security projects planned for the Albury region.

[11] A black start is the process to restore a power station or a part of an electric grid to operation without relying on the external transmission network.

[12]According to Transpower's Branch Rating Reports for Albury

BELL'S POND GXP GEOGRAPHIC AREA



5.9.2. BELLS POND

OVERVIEW

The Bells Pond area is predominantly irrigation dairy farming. The Oceania Dairy Limited (ODL) dairy factory is located near Glenavy just off State Highway One.

The largest irrigation scheme is presently the Waihao Downs irrigation scheme[13]

NETWORK CONFIGURATION

Appendix A.6.2 describes the network configuration and shows the schematic diagram of the Bells Pond GXP and zone substations.

5.9.2.1. DEMAND FORECAST

Demand forecasts for the Bells Pond GXP, and regional zone substations are shown below with further details provided in Appendix A.5.

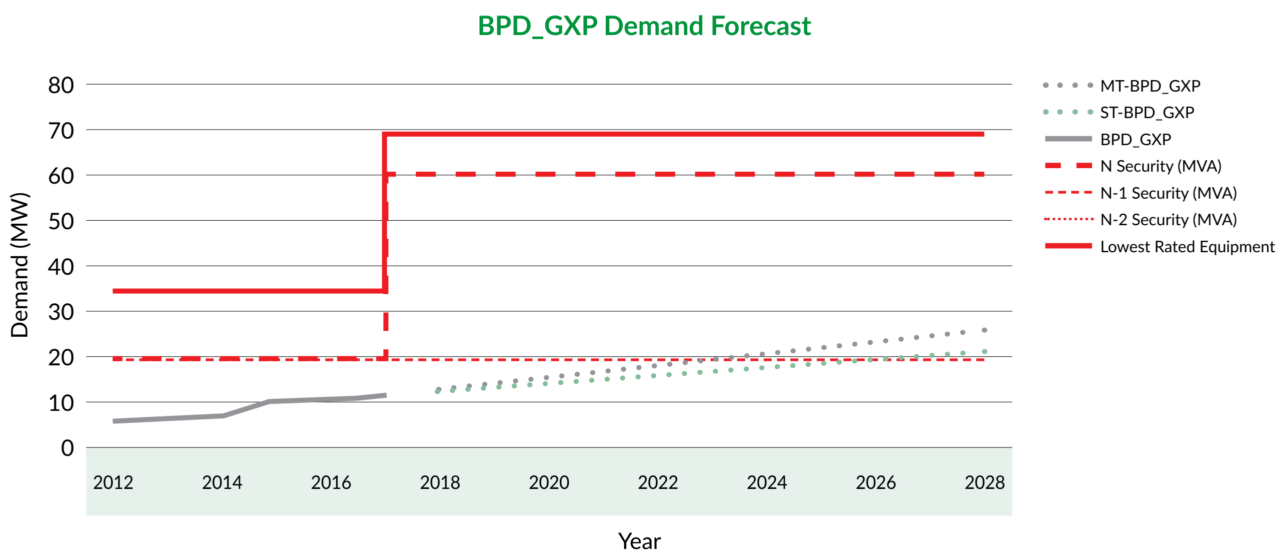


Figure 5.8 Bells Pond GXP demand forecast

[13] www.mgiirrigation.co.nz

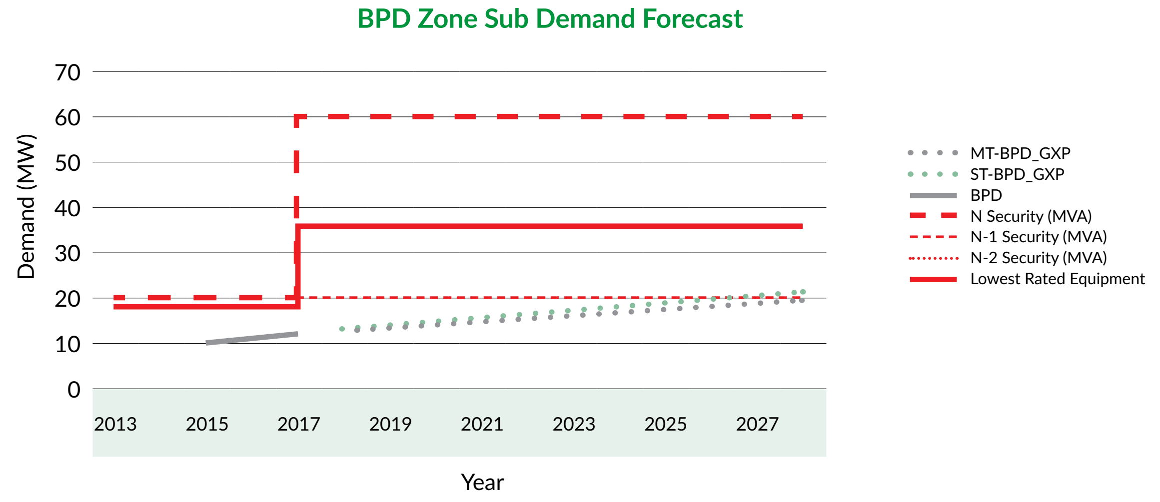


Figure 5.9 Bells Pond Zone Sub demand forecast

Table 5.5 Bells Pond region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)
Bell Pond GXP	60	20	34.29	13.68	14.89	16.09	17.29
Bell Pond zone substation	60	20	18.01	13.04	13.56	14.10	14.66
Cooneys road zone substation	15	-	22.4	3.45	3.45	3.45	3.45

Load continues to grow in response to the farming and irrigation activities in the area. To the best of our knowledge, no large irrigations schemes are planned in the region.

The ODL dryer 1 has been commissioned with a load 2.6 MVA and they have commissioned an ultra high temperature Treatment (UHT) and canning plant in 2017 which increased their total load to around 4 MVA. As the factory grows beyond what Bells Pond can supply at 33 kV, a permanent 110 kV supply will be required.

The Waihao Downs irrigation scheme currently takes up to 3.2 MW when all the pumps are running. A future stage 2 to this scheme could add another 3 MW to Bells Pond. We have not yet received a network application for the additional demand.

5.9.2.2. SECURITY OF SUPPLY

Table 5.6 Bells Pond and Cooneys Road security of supply

Zone sub/ load centre	Actual security level	Target security level	Shortfall from target
Bells Pond Rural	N-0.5	N	Back up supply from Studholme. Studholme can presently take the majority of the 11 kV load if both Studholme transformers are in service (the spare Studholme capacity will be eroded should Fonterra build a dryer at Studholme). Some irrigation and ODL would have to be disconnected to put Bells Pond on Studholme. Encourages consumers to be self-sufficient for their essentials, as for Civil Defence emergencies. Second transformer planned for 2017/2018.
Dairy processing ODL	N-0.5	N	Supply is not presently N-1, as agreed by ODL. 0.5 MW of back up supply from Studholme is available. Further investment will be needed if and when ODL want to increase supply security to N-1.

5.9.2.3. EXISTING & FORECAST CONSTRAINTS

The Bells Pond rural area has back up supply from adjacent 11 kV feeders from Studholme. Studholme zone substation can presently take the majority of the 11 kV load if both Studholme transformers are in service. This spare capacity at Studholme will be eroded should Fonterra build a dryer at their Studholme dairy factory (they have resource consent, but we have not received a network application for the additional demand).

The ODL dairy factory supply is presently N security, as agreed by ODL. 0.5 MW[14] of back up supply from an adjacent 11 kV feeder from Studholme is available. Further investment will be needed if and when ODL want to increase security to N-1.

With both Bells Pond and Studholme GXPs connected to the Waitaki-Oamaru-Timaru circuit 2, we are constrained in terms of our offtake at these two GXPs. This constraint will limit the amount of load growth we can accommodate. Transpower has implemented a special protection scheme (SPS) to curtail load in the event that one of the two Waitaki 110 kV circuits are lost.

The SPS will in certain instances allow us enough time to run our ripple injection plant with a view to shed irrigation load, thereby maintaining supply to dairy processing plants and milking sheds, in order to prevent the scheme from turning off all load indiscriminately. In addition Transpower will offload Studholme GXP onto the Timaru GXP with Bells Pond remaining on the Waitaki feed.

5.9.2.4. MAJOR GROWTH AND SECURITY PROJECTS

This section is a summary of major projects planned for the Bells Pond region.

Improve security of supply to the ODL dairy factory	
Estimated cost (concept)	Approximately $2 M
Expected project timing	T+2 year on request from ODL

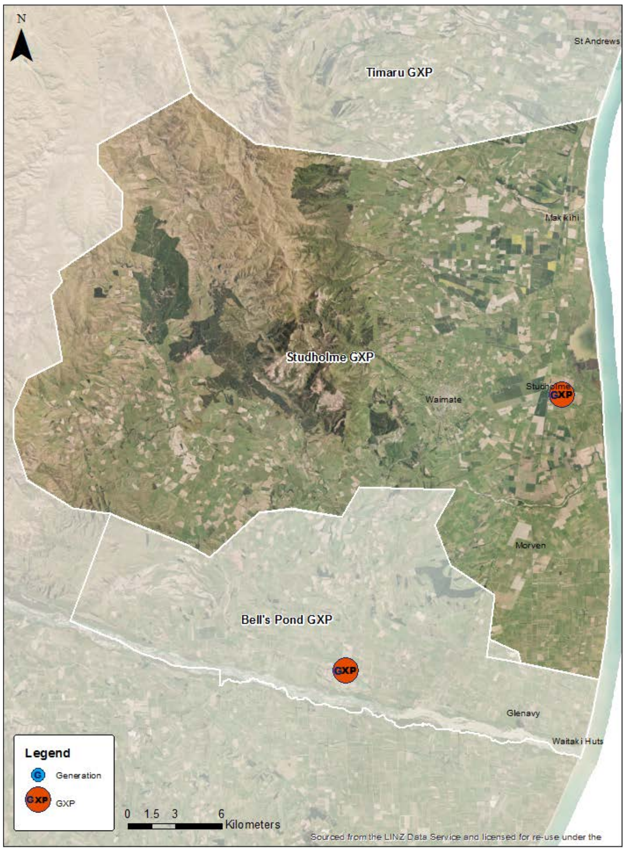
This investment will only occur when ODL requests the security of supply to be upgraded to above N security. Until requested, we will not include any projects in our planning.

Presently ODL has N security. There is a limited backup supply available (approximately 0.5 MVA) from an adjacent 11 kV feeder from Studholme zone substation. This supply is available only after manual switching. To provide solid[15] N-1 security, a second transformer will need to be installed at Cooneys Road zone substation with a second 33 kV subtransmission feeder circuit breaker at Bells Pond zone substation.

[14] Summer season

[15] Solid N-1 means no load will be lost due to a single failure

STUDHOLME GXP GEOGRAPHIC AREA



5.9.3. STUDHOLME (WAIMATE)

OVERVIEW

The Waimate area is administered by the Waimate District Council and is the southernmost area of South Canterbury. Sizeable irrigation development has occurred here, serving to stabilise the population of the Waimate township. Another irrigation scheme, Hunter Downs Water, is planned for the area between Studholme and St Andrews. The Oceania Dairy Limited factory is also a substantial employer in the region and thus supports a stable level of population for townships like Waimate.

Fonterra operate the Studholme dairy factory, which is located in close proximity to the Studholme GXP.

NETWORK CONFIGURATION

Appendix A.6.3 describes the network configuration and shows the schematic diagram of the Studholme GXP and zone substations.

5.9.3.1. DEMAND FORECAST

Demand forecasts for the Studholme GXP, and the regional zone substation are shown below with further details provided in Appendix A.5.

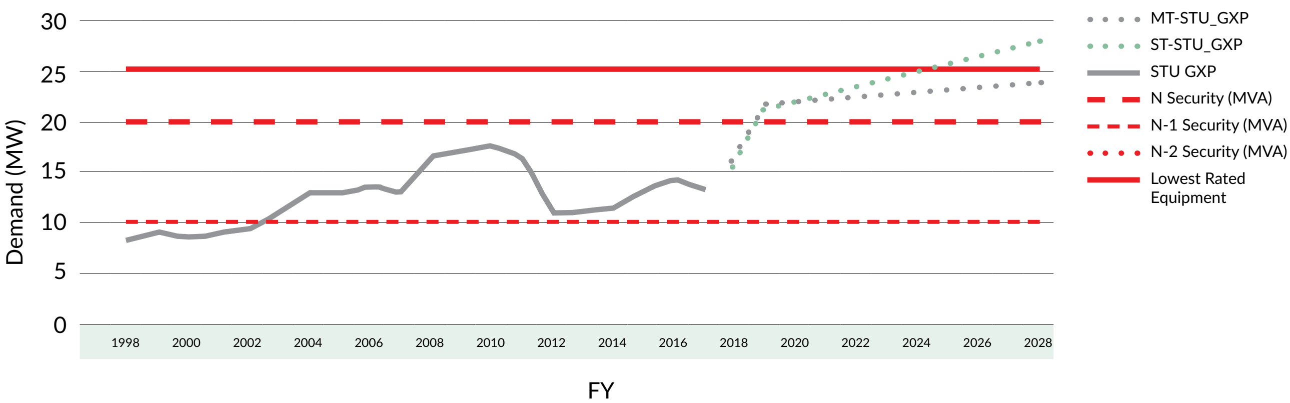


Figure 5.10 Studholme (Waimate) GXP demand forecast

Table 5.7 Studholme (Waimate) region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)
Studholme GXP*	20	10	25.20	16.44	21.49	21.77	22.04

*Transpower equipment (refer to www.transpower.co.nz).

The demand in this region is summer peaking from strong growth from the Studholme dairy factory, arable/dairy farming, and irrigation loads.

The Hunter Downs Water scheme[16] will proceed pending the approval of funding by the government. Hunter Downs Water's board of directors on 21 December 2017 confirmed the company had the shareholders it needed to proceed with the $110 million Hunter Downs Water scheme, which will cover 12,000 hectares of land between Waimate and Timaru.

Fonterra has resource consent for a second dryer at the Studholme dairy factory, but has not applied for additional demand or has indicated to us if or when this will proceed. Therefore this step increase does not feature in our load growth forecast.

5.9.3.2. SECURITY OF SUPPLY

Table 5.8 Studholme security of supply

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
Waimate Residential	N-1	N-1 (switched)	Limited 11 kV rings from Studholme. Limited fault backup from Bells Pond.
Waimate Rural	N-0.5	N-0.5	Limited fault backup from Bells Pond and Pareora Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
Fonterra 11 kV	N	N	Load over 3 MVA requires customer investment for dedicated feeders/cables. Present load restricting load growth and increasing voltage problems towards end of feeders.

5.9.3.3. EXISTING & FORECAST CONSTRAINTS

The existing load on Studholme GXP is greater than the N-1 security (offered from a single transformer). When Bells Pond GXP is taken out of service, the Studholme GXP and zone substation then supply as much load as the Studholme 11 kV distribution feeders to Bells Pond and Cooneys Road can support (voltage constraint).

The Studholme GXP and zone substation can supply up to 0.5 MW of load to the Cooneys Road zone substation to assist ODL when the main supply from Bells Pond is unavailable.

The Waimate residential area have limited 11 kV distribution feeder rings from the Studholme zone substation and has limited back up from adjacent 11 kV distribution feeders from Bells Pond mainly due to the distances involved (voltage constraint).

The Waimate rural area has limited back up from adjacent 11 kV distribution feeders from Bells Pond and Pareora also mainly due to the distances involved (voltage constraint).

There is a challenge throughout this region with keeping the voltage within the regulatory limits. This is evident by the number of voltage regulators deployed already.

For any load at the Studholme dairy factory over 3 MVA will require network investment for dedicated feeders/cables.

The feeders to the north of Studholme and south of Pareora will need network investments to support the Hunter Downs Water scheme load. These feeders already have the maximum number of voltage regulators and capacitors applied.

STU GXP presently has two 10 MVA transformers that are connected giving 20 MVA[17] capacity of N security. If one of the transformers fails, Transpower would disconnect the transformers while the supply is off and then re energise the healthy transformer and restrict demand to 10 MVA. Present loads indicate that if this occurred, some irrigation would have to be turned off until the faulty transformer has been repaired or replaced.

We have a temporary arrangement with Transpower for a 110 kV bus tie during the milk flush, to give the Fonterra Studholme dairy factory improved security. Transpower has

[16] www.hunterdowns.co.nz

[17] Each transformer is capable of running at 11 MVA each.

installed a special protection scheme at Studholme GXP to cater for the summer security needs. Transpower could still remove the tie; if this occurs the dairy factory will have N security of supply. Presently N security is contracted for with Fonterra.

5.9.3.4. MAJOR GROWTH AND SECURITY PROJECTS

This section is a summary of major projects planned for the Studholme (Waimate) region.

Fonterra Studholme dairy factory expansion	
Estimated cost (concept)	TBC
Expected project timing	T+2 year on request from Fonterra

This project will only be included in our planning process, when Fonterra provides us with an application for additional load. The capital investment is dependent on the size of the additional load, therefore options have not been established. As a minimum it would need to include dedicated feeders for the dairy factory to avoid voltage issues towards the end of the 11 kV distribution feeders. It also requires additional transformer capacity at the Studholme GXP.

Fonterra Studholme dairy factory N-1 security upgrade	
Estimated cost (concept)	TBC
Expected project timing	T+3 year on request from Fonterra

Similar to the previous project discussed, we will only include any projects to provide N-1 on request by Fonterra. The investment needed is increased transformer capacity at the Studholme GXP and discussions with Transpower on how the transmission grid can provide the N-1 security[18].

Hunter Downs Water (HDW) irrigation scheme pump station capacity	
Estimated cost (concept)	Approximately $23.96 M
Expected project timing	T+3 years on request from Hunter Downs Water

The last information received from HDW puts the total load at 8.5 MW. Based on last received information for required capacity and pump locations, the new load cannot be supplied from the Studholme GXP and zone substation. There are various options to supply the multiple pump sites. Wherever possible we will be using existing infrastructure. The HDW load is significant and spread across a wider area between the Studholme GXP and the Pareora zone substation.

When we receive final load and location information we will analyse and cost all the options.

The likely solution will be a combination of additional or new GXP capacity, new 33 kV subtransmission lines, new and upgraded 11 kV distribution lines and a combination of 33/400 V and 11/400 V distribution stations.

Hunter Downs irrigation scheme on-farm capacity	
Estimated cost (concept)	TBC
Expected project timing	T+3 year on request from farmers

No information has been received regarding on-farm load requirements. Based on the area of land to be irrigated and the load requirement of the existing Waihao Downs irrigation[19] on-farm requirement, we have carried out some preliminary assessments.

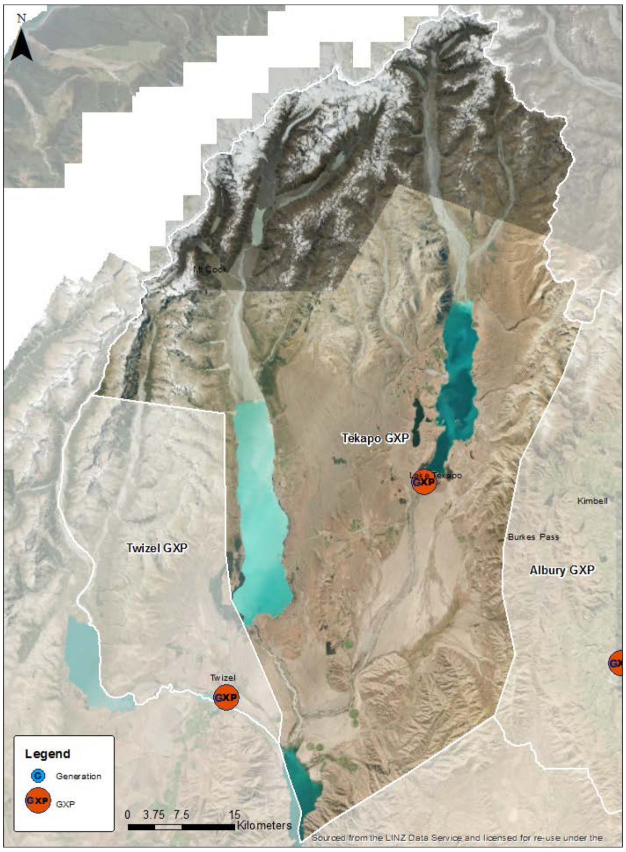
The existing 11 kV distribution feeder infrastructure will need upgrading. The majority of the distribution lines in the scheme area are single phase lines which, depending on the type and maximum demand of the on-farm load, may have to be re-built. Existing three phase circuits may not have sufficient capacity requiring a total rebuild.

We regard this project as an ideal opportunity to consider non-network solutions and new technologies such as standalone power systems using PV, batteries and diesel or biomass generation. Depending on the application, solar pumps could also form part of some solutions.

[18] Refer to System Security Forecast from Transpower.

[19] The Waihao Downs irrigation scheme is operated by Morven Glenavy Ikawai Irrigation Company Ltd.

TEKAPO GXP GEOGRAPHIC AREA



5.9.4. TEKAPO

OVERVIEW

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

Genesis Energy has generation assets at Lake Tekapo. Growth is occurring in the Tekapo area, with plans for further irrigation development in the Mackenzie Basin, and a new retail development in the Tekapo Township planned for 2017 onwards.

NETWORK CONFIGURATION

Appendix A.6.4 describes the network configuration and shows the schematic diagram of the Tekapo GXP and zone substations.

5.9.4.1. DEMAND FORECAST

Demand forecasts for the Tekapo GXP, and regional zone substations are shown below with further details provided in Appendix A.5.

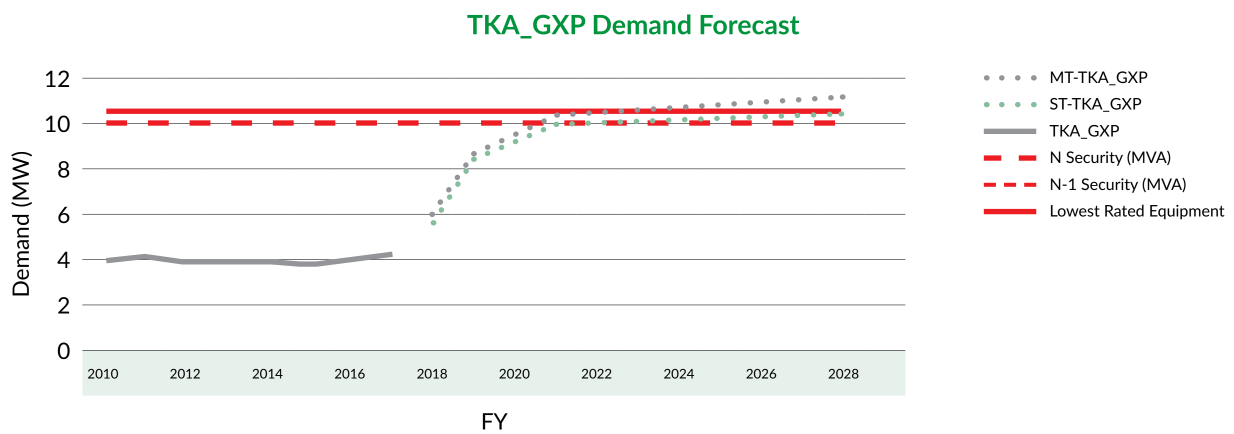


Figure 5.11 Tekapo GXP demand forecast

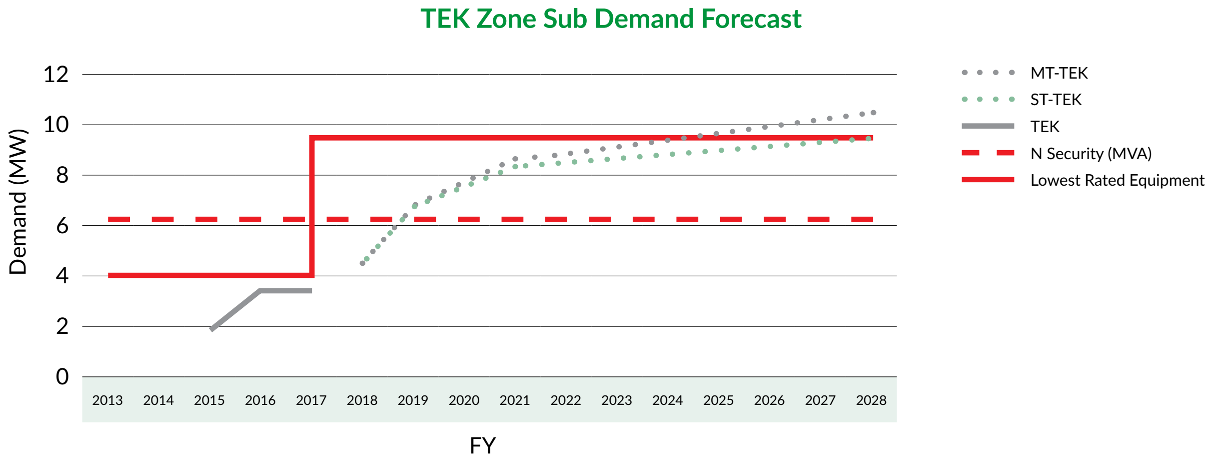


Figure 5.12 Tekapo Zone Sub demand forecast

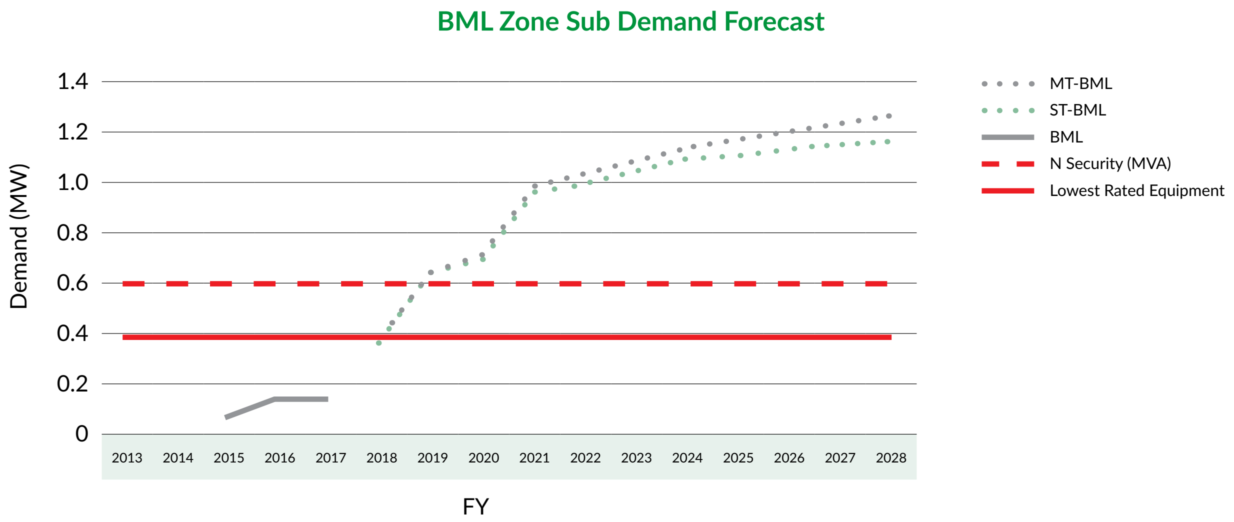


Figure 5.13 Balmoral Zone Sub demand forecast

Table 5.9 Tekapo region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)
Tekapo GXP*	10	-	10.50	6.00	8.55	9.58	10.22
Tekapo zone substation	6.25	-	4.04	4.60	6.72	7.82	8.56
HaldonLily Bank zone substation**	1	-	2.55	0.45	0.46	0.47	0.49
Balmoral zone substation**	0.60	-	0.38	0.36	0.63	0.70	0.98

5.9.4.2 SECURITY OF SUPPLY

Table 5.10 Tekapo, Mt Cook, Glentanner security of supply

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
Tekapo CBD	N-0.5	N-1 (switched)	No alternate supply to station. Mobile substation can be connected. Limited 11 kV rings. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
Mt Cook and Glentanner	N	N	No alternate supply to station. Mobile substation can be connected at Unwin Hut to supply Mt Cook. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
Tekapo Rural	N	N	Radial lines, little backup. Generator port on 11 kV at HaldonLilybank. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.

5.9.4.3. EXISTING & FORECAST CONSTRAINTS

There is considerable load growth occurring in and around the Tekapo township. This includes subdivisions, additional commercial central business district, and hotels. The Tekapo Springs complex is also increasing their demand.

The increasing demand leads to increased load on the feeders into the township. Because these feeders also continue on through the township into the rural area east of the township, they are becoming voltage constrained. With no voltage control capability at the Balmoral and HaldonLilybank zone substations, network investment is needed to remove the voltage constraints.

Between our Tekapo zone substation and the township, the 11 kV distribution feeders are overhead lines. There is a request by a landowner to underground or relocate these feeders to make way for a residential subdivision.

There is additional irrigation and dairy conversion load growth occurring at the end of our Simons Pass 22 kV distribution feeder.

The existing ripple injection plant is a 500 Hz rotary plant. The functionality of this plant will reduce our ability to consider demand side management as an option to defer network investments.

* Transpower equipment (refer to www.transpower.co.nz).

** HaldonLily Bank and Balmoral are 11/22 kV stepup transformer substations

5.9.4.4. MAJOR GROWTH AND SECURITY PROJECTS

Tekapo zone substation power transformer upgrade

Estimated cost (concept)	$2.5M
Expected project timing	2020-2022

As shown from the demand forecast plot (Figure 5.12), demand is expected to reach the transformer rated capacity of 6.25 by FY 2019. An Engineering investigation is required to determine the best upgrade strategy to ensure that the substation capacity will keep up with the growth in the region and improving the security of supply to the area. The timing of this project can be deferred if a supply is established from Twizel GXP to feed the Simons Pass proposed irrigation and dairy conversions.

TKA GXP stepup transformer upgrade

Estimated cost (concept)	TBC
Expected project timing	2020-2022

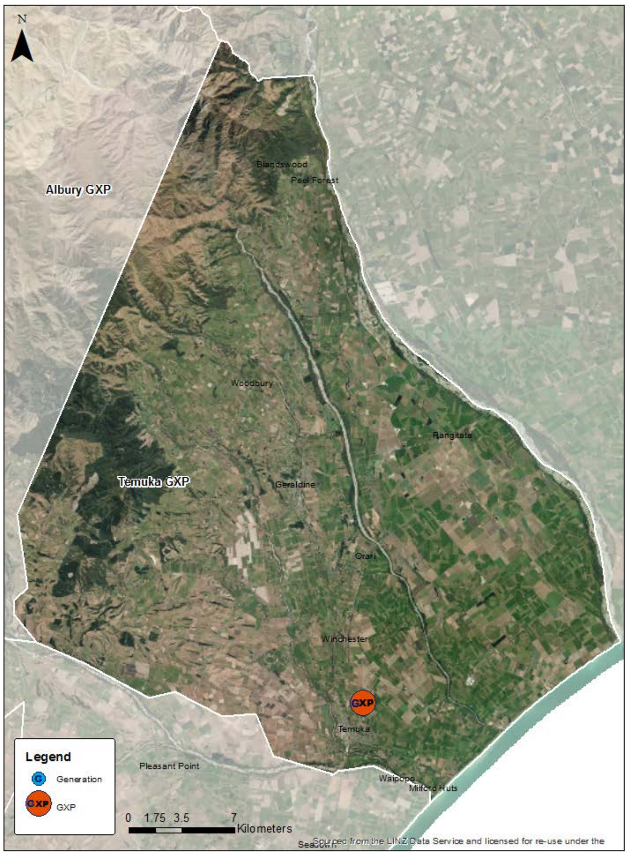
As per our load forecast the 10 MVA capacity of the GXP will be reached by 2021. Hence, we will need to approach Transpower to investigate the possibility of GXP capacity upgrade and whether improvement to the security is feasible given the growing tourism criticality of this area. The timing of this project can be deferred if a supply is established from Twizel GXP to feed the Simons Pass proposed irrigation and dairy conversions.

Balmoral zone substation rebuild

Estimated cost (concept)	$1.0M
Expected project timing	2018-2019

To supply the proposed irrigation and dairy conversions load increase in Simons Pass, the Balmoral substation will require an upgrade with on load tap changer (OLTC) capabilities. The substation will need to have bidirectional capabilities to ensure future proofing if a Twizel-Tekapo tie is built and utilised in the future.

TEMUKA GXP GEOGRAPHIC AREA



5.9.5.1. DEMAND FORECAST

Demand forecasts for the Temuka GXP, and regional zone substations are shown below with further details provided in Appendix A.5.

5.9.5 TEMUKA

OVERVIEW

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

The other larger urban area is Geraldine, a township with a population of 2300. Geraldine benefits from the passing of tourists on the way to Tekapo and Queenstown.

NETWORK CONFIGURATION

Appendix A.6.5 describes the network configuration and shows the schematic diagram of the Temuka GXP and zone substations

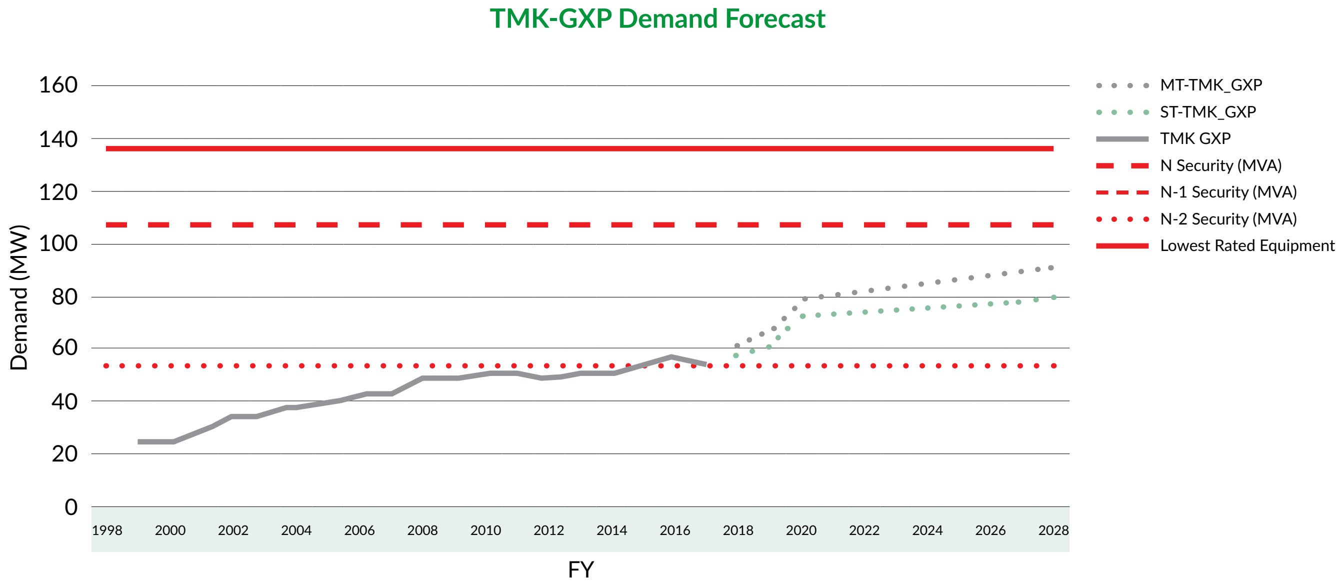


Figure 5.14 Temuka GXP demand forecast

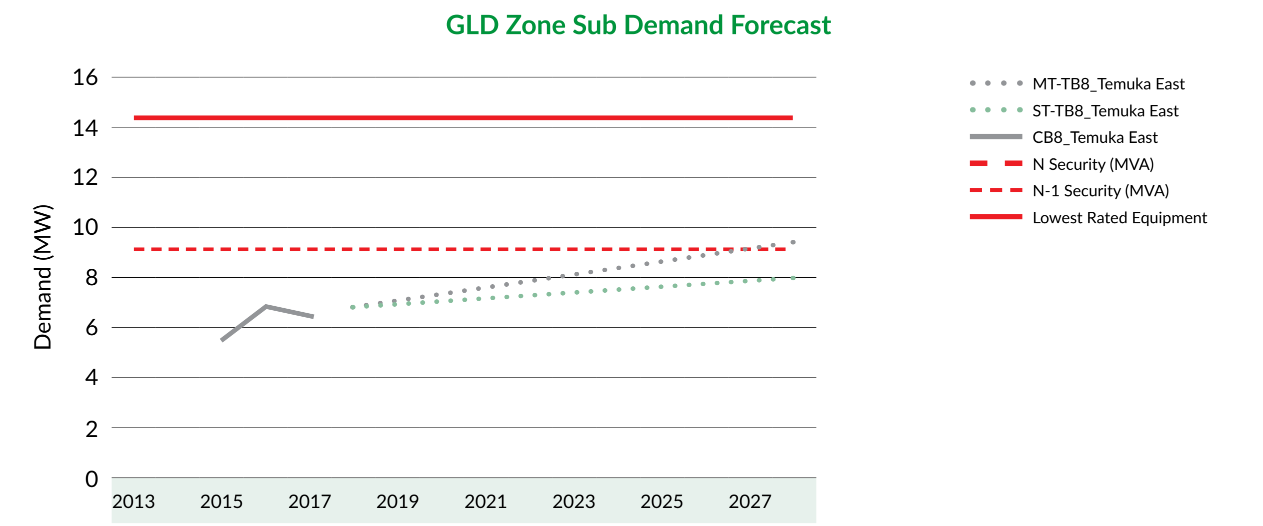


Figure 5.15 Geraldine zone substation demand forecast

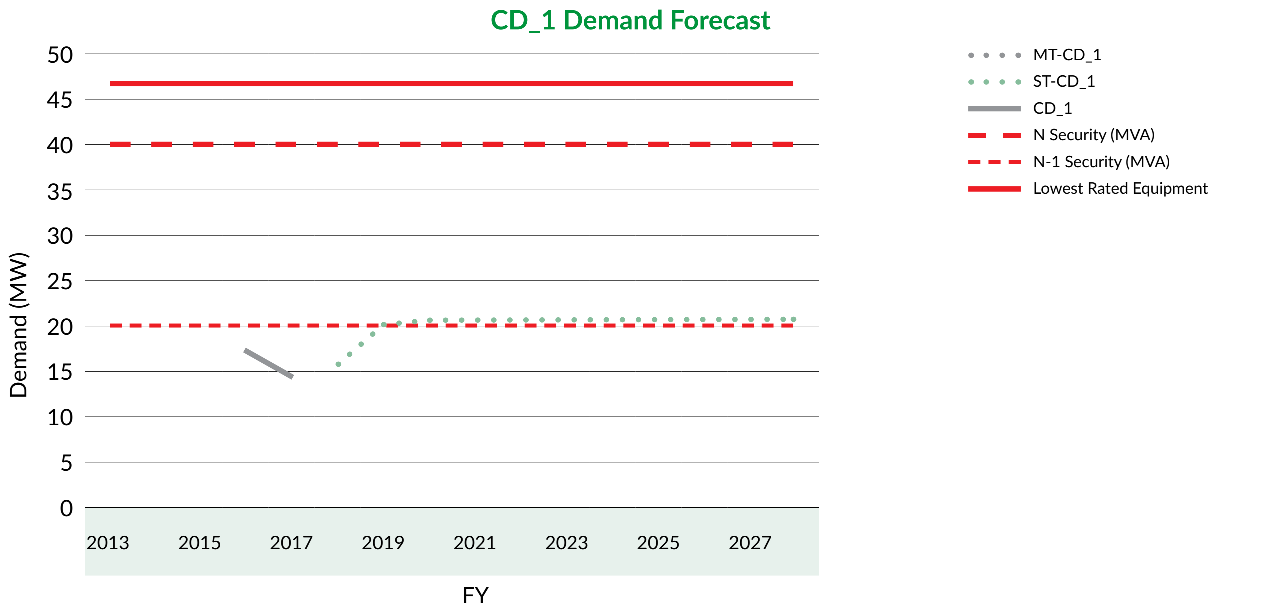


Figure 5.16 Clandeboye 1 Zone Sub demand forecast

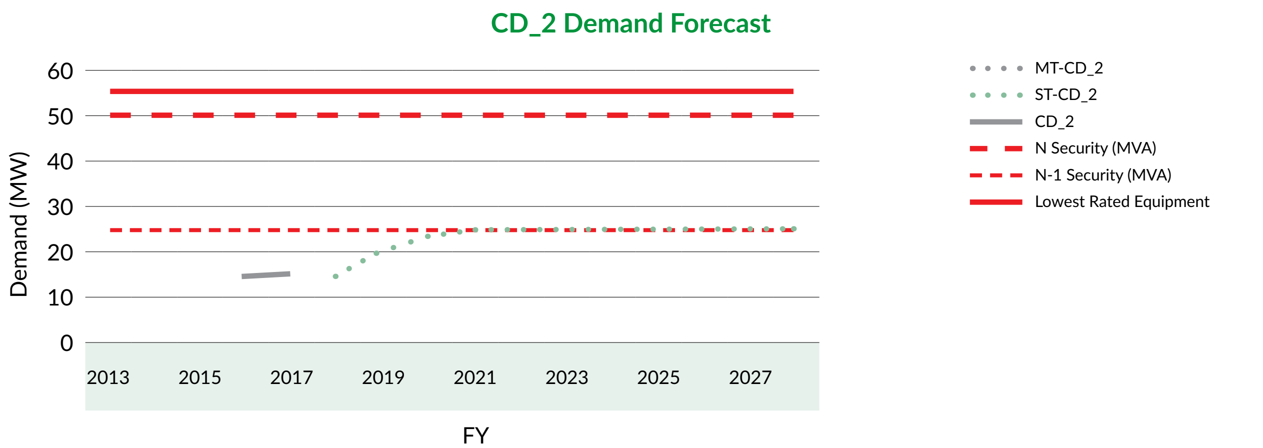


Figure 5.17 Clandeboye 2 Zone Sub demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)
Temuka GXP*	108	54	137.20	62.07	71.35	77.78	81.52
Temuka zone substation	50	25	20.38	12.84	13.23	13.64	14.06
Geraldine zone substation	9	-	14.29	6.84	7.05	7.27	7.49
Rangitata 1 zone substation	15	-	10	5.35	5.52	5.68	5.86
Rangitata 2 zone substation	15	-	7.20	4.02	4.14	4.27	4.40
Clandeboye 1 zone substation**	40	20	46.86	15.84	19.64	20.84	20.84
Clandeboye 2 zone substation**	50	25	55.84	15.16	18.96	22.52	24.60

* Transpower equipment (refer to www.transpower.co.nz).
** Clandeboye 1 and 2 zone substation are dedicated to the Clandeboye Fonterra dairy factory.

In this region peak demand occurs during summer based on the predominant dairy and irrigation load. The Fonterra Clandeboye load is increasing with plans for more processing capacity. With this increased load on the Temuka GXP, the GXP is no longer able to supply at N-1 security. Transpower has been commissioned for a concept design report (CDR) to upgrade the Temuka GXP.

5.9.5.2. SECURITY OF SUPPLY

Table 5.12 Temuka and Clandeboye security of supply

Zone sub/load centre	Actual	Target	Shortfall from target
Temuka Residential	N-1	N-1 (switched)	None.
Temuka Rural	N-0.5	N	Limited fault backup from Geraldine, Rangitata, Pleasant Point, and Timaru. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
Clandeboye CD1 and CD2	N-1 for 33 kV subtransmission circuits and zone substations.	N-1	None
Rangitata	N-1 for 33 kV circuits and zone substation transformers.	N	None. N-1 for 33 kV circuits only as long as the load is less than 10 MW. Some load can be shifted onto 11 kV backup from Geraldine and Temuka.
Geraldine	N-0.5	N-0.5	33 kV investments to be considered.

5.9.5.3. EXISTING & FORECAST CONSTRAINTS

The additional load at the Fonterra Clandeboye dairy factory will further erode the N-1 security at the Temuka GXP. Work is continuing with Transpower to fully reinstate the N-1 security. Engineering investigations are under way to establish the impact of the new load on the N-1 security on the 33 kV subtransmission feeders from the Temuka GXP to the Clandeboye zone substations.

For the Temuka rural area there is limited backup from Geraldine, Rangitata, Pleasant Point and Timaru zone substations. Backup capacity is being eroded because of steady load growth. A detailed engineering investigation will be undertaken next year to establish options to ensure we will continue to meet our security standards.

At the Rangitata zone substation we do not meet our security standards. There is no N-1 security due to the 11 kV bus coupler operated normally open. Also there is only N-1 security on the 33 kV subtransmission feeders to Rangitata zone substation for loads less than 10 MW. A detailed engineering investigation will be undertaken next year to establish options to ensure we will continue to meet our security standards.

The low voltage (230/400 V) reticulation in urban areas of Temuka and Geraldine are starting to show challenges in regard to voltage levels. Information is starting to surface that the voltage levels are on the high side. This can cause problems for distributed generation, in particular solar panels. This is also a challenge for the many hut communities in the area. A project has been initiated to establish the extent of the challenges and then determine options to resolve any challenges identified. In the meantime the hut community reticulation has been added as a congested area for distributed generation and published on our website in accordance with Part 6 of the Electricity Industry Participation Code[20].

5.9.5.4. MAJOR GROWTH AND SECURITY PROJECTS

Temuka GXP upgrade	
Estimated cost (concept)	$9.25M GXP substation $15M 110 kV transmission line upgrade
Expected project timing	2018-2020

We have asked Transpower to commission a Concept Design Report (CDR) for the Temuka GXP upgrade. The CDR was received on 22 December 2017.

The upgrade project will make the special protection scheme on the 110/33 kV transformers obsolete.

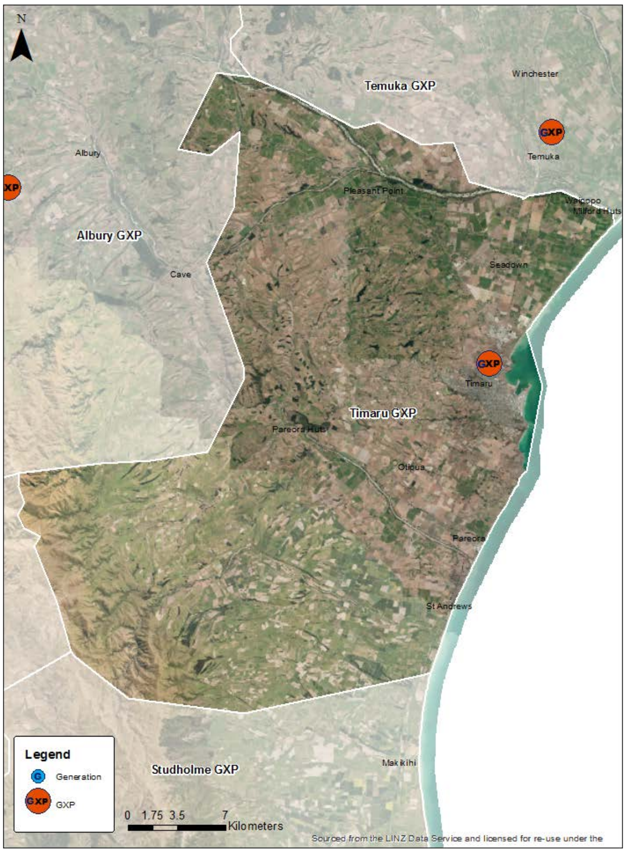
The upgrade will be in two parts: upgrade of the GXP substation and the upgrade of the 110 kV transmission lines from Timaru to Temuka.

Geraldine transformer upgrade	
Estimated cost (concept)	$1.5M
Expected project timing	2022-2023

The Geraldine area load is steadily increasing. This is prompting a power transformer upgrade at the Geraldine zone substation by 2022.

[20] The Electricity Industry Participation Code from the Electricity Authority is a mandated code under the Electricity Industry Act 2010.

TIMARU GXP GEOGRAPHIC AREA



5.9.6. TIMARU

OVERVIEW

The majority of our 32,829 consumers live in the Timaru area on the east coast, with approximately 13,500 living in or near Timaru City. Timaru is the hub of South Canterbury, connecting the road networks west, north, and south. The city serves a CBD, a main residential population, and a range of industries and commercial businesses including two meat processing plants; a container, timber, and bulk cement port; a brewery; wool scour; and food processing plants. The majority of load growth in the city comes from industrial development in the Washdyke area and the port area.

The port operations at PrimePort Timaru[21] continue to be an important part of the region's economy. Holcim started its operations at PrimePort Timaru (a partner of the Port of Tauranga) for the movement of its bulk cement in December 2015 and is now running at full load having added a combined load of up to 3 MW to the supply from Grasmere Street and North Street substations.

5.9.6.1. NETWORK CONFIGURATION

Appendix A.6.6 describes the network configuration and shows the schematic diagram of the Timaru GXP and zone substations.

5.9.6.2. DEMAND FORECAST

Demand forecasts for the Timaru GXP, and regional zone substations are shown below with further details provided in Appendix A.5.

[21]More information about PrimePort Timaru can be found at www.primeport.co.nz.

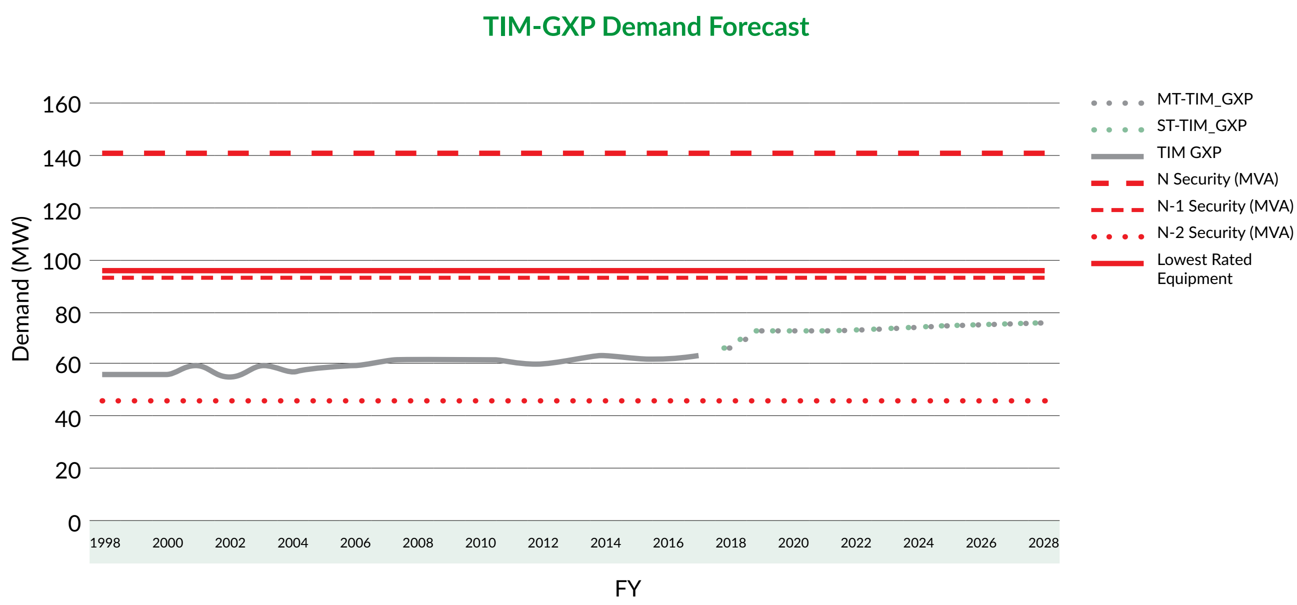


Figure 5.18 Timaru GXP demand forecast

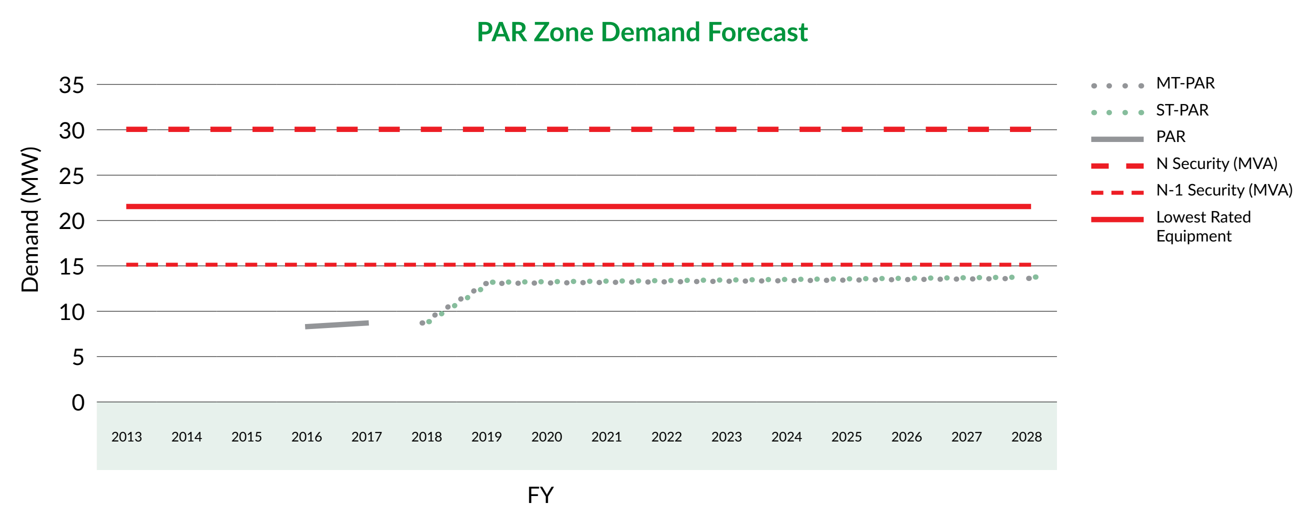


Figure 5.19 Pareora Zone Sub demand forecast

Table 5.13 Timaru region demand forecasts

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)
Timaru GXP*	141.00	94.00	96.60	66.38	71.85	72.21	72.58
Timaru zone substation	141.00	94.00	96.60	66.65	72.13	72.54	72.95
Pleasant Point zone substation	6.25	-	14.63	4.90	4.93	4.95	4.98
Pareora zone substation	30.00	15.00	21.61	8.87	13.12	13.19	13.27
Grasmere zone substation**	31.29	23.46	-	27.12	28.18	28.34	28.50
North Street zone substation**	30.89	15.44	-	13.28	13.36	13.43	13.51
Hunt Street zone substation**	22.46	16.85	-	9.78	10.73	10.79	10.85

* Transpower equipment (refer to www.transpower.co.nz).

** Grasmere, North Street and Hunt Street are switching stations (no transformation of voltages).

Timaru is seeing load steadily increase in the Port and Washdyke areas along with the residential subdivisions that are taking place in the western area.

The Timaru District Council has adopted an in-fill policy, that is, they are promoting higher density residential in the existing urban areas. This policy could lead to network investment on the low voltage reticulation. Presently only overhead upgrades up to 50 meters in length is permitted under the district plan. We have been lobbying the Timaru district Council to have overhead upgrades over 50 meters to be a permitted activity. This has been done through the District Plan review process and their Growth Management Strategy consultation.

5.9.6.3. SECURITY OF SUPPLY

Table 5.14 Timaru, Pareora, Pleasant Point security of supply

Zone sub/load centre	Actual security level	Target security level	Configuration and options
TIM 33 kV step up zone substation	N-1 for Pareora N for Pleasant Point	N-1 for Pareora N for Pleasant Point	Two step-up transformers feed a split 33 kV bus arrangement. Pareora on each side of bus and Pleasant Point is fed off one bus with short duration loss with outage to that bus, until a tie is made to the remaining 33 kV bus.
Timaru Residential	N-1 (switched)	N-1 (switched)	None
Timaru Rural	N-0.5	N-0.5	Limited fault back up from adjacent feeders from Timaru and then as second resort Pareora, Pleasant Point and Temuka. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.
Washdyke/Seadown	N-1 (switched)	N-1 (switched)	Four new 33 kV cable circuits from Seadown to Timaru to run at 11 kV have been installed in 2017.
Timaru CBD (Grassmere, Hunt Street, and North Street)	N-1 (switched)	N-1 (switched)	None
Redruth	N-1 (switched)	N-1 (switched)	None
Port	N-1 (switched)	N-1 (switched)	None
Pareora 33/11°kV zone substation	N-1 for transformers, 10 MVA for sub-transmission circuits	N-1 for all periods.	Some load can be transferred to Studholme and Timaru in an emergency.
Pleasant Point 33/11 kV zone substation	N-0.5	N	Some load can be transferred from Pleasant Point to Albury, Temuka and Timaru in an emergency. Encourages consumers to self-manage their risk mitigation for outages for example, a Civil Defence emergency.

5.9.6.4. EXISTING & FORECAST CONSTRAINTS

Timaru GXP: The 220/110 kV inter-connection transformers supply the growing loads of Albury, Tekapo, Temuka, Timaru and Studholme. On occasion, additional load is required to be supplied south to Bells Pond and Oamaru. During the dairy season Studholme is tied through. A tripping of the Waitaki feed into Studholme will lead to the inter-connection transformers combined load being taken beyond their 120 MVA individual rating; a special protection scheme is mitigating overloading the transformers by shedding load. Transpower is investigating how to remedy this in the long term.

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

- The compact MED is supplied at 11 kV from TIM GXP mainly via underground assets.
- Due to a difference in phase angle between the then MED (Timaru metro area) and the surrounding SCEPB areas, (Temuka and Geraldine) the networks cannot be easily meshed to improve security of supply. These networks must first be turned off before they can be connected to improve reliability.
- There are areas of supply at the boundary of the historical areas that can be improved by greater integration of the assets of the two legacy networks (e.g. by upgrading 11 kV lines and cables, and introducing additional, or upgraded, points of connection between the two networks).

The subtransmission circuits to Pareora zone substation are voltage constrained if total load exceeds 20 MW, or 10 MW in a contingent event (e.g. one of the circuits or a Pareora power transformer out of service).

Part of the 11 kV feeders into the port area requires undergrounding to provide improved safety around loading areas. In conjunction with this undergrounding a reconfiguration of the 11 kV system in the port area is to be undertaken to improve security and maintainability.

In the Western area of Timaru there are 11 kV distribution feeders that are run through the back of residential sections. This is becoming a maintainability issue in relation to access. Projects are underway to replace these feeders with underground cables in public roads.

5.9.6.5. MAJOR GROWTH AND SECURITY PROJECTS

CBD underground substations	
Estimated cost (concept)	$2.5M
Expected project timing	2019-2024

The Timaru CBD area is supplied from underground distribution substations. These substations include HV switchgear, 11/0.4 kV transformers and LV reticulation protection. These substations are subject to confined space considerations and arc flash hazards. There is no one solution to all substations. This project is considering each substations solution options for refurbishment, replacement or relocation.

400V Lucy link box replacements	
Estimated cost (concept)	$2.25M
Expected project timing	2019-2024

From a full condition assessment on all our Lucy boxes (in-ground link boxes in the Timaru CBD area), it was found a number of them to be inoperable and a large proportion had over heating issues. This project will replace all Lucy boxes with modern above ground equivalents.

Western Timaru 11 kV distribution feeder relocation	
Estimated cost (concept)	$1.97M
Expected project timing	2019-2021

This project continues the work to relocate overhead high voltage feeders from the back of private properties to underground cables located in the public road. The Orbell feeder relocation is one example of this work.

This project also includes the relocation of overhead lines to underground in the port area (Dawson street) due to safety concerns regarding vehicle movements and loading activities.

Ripple Plant & building renewal	
Estimated cost (concept)	$0.5M
Expected project timing	2018-2019

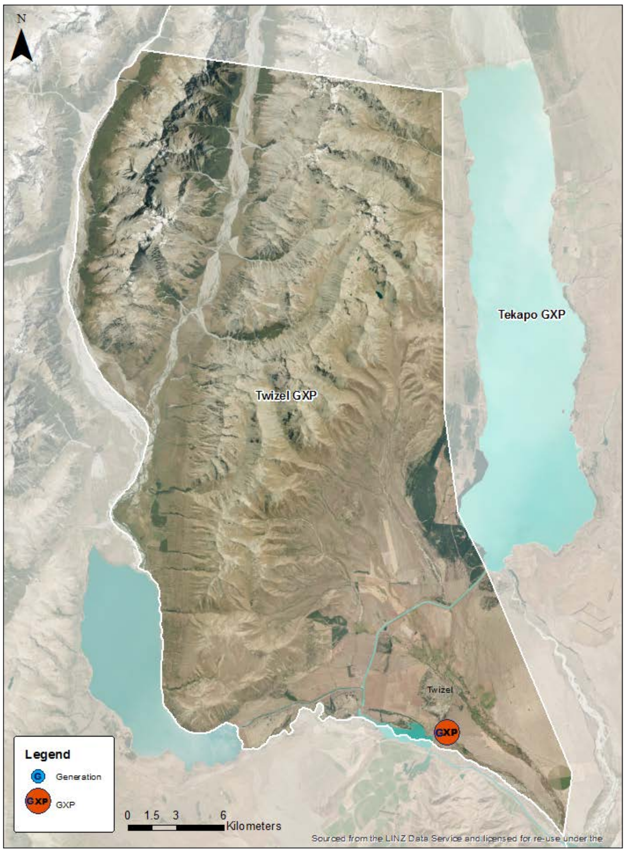
The existing timaru ripple load control plant consists of three main parts: the coupling cell (including isolating/earthing switch, capacitors, inductors and isolating transformer); the static frequency converter; and the injection controller.

The existing Zellweger SFU-3/25 converter and its coupling cell are approximately 36 years old and they have exceeded their normal service life by at least 10 years. It has therefore been decided to replace the plant, coupling cell, and injection controller. In addition, the ripple plant building's exterior cladding contains asbestos and it has corrugated asbestos cement roofing. Consequently it is prudent to replace the whole plant including the building. The budget for 2018-19 will include for planning, design, and procurement of new plant and building.

33 kV Zone Substation switchgear upgrade	
Estimated cost (concept)	$3.7M
Expected project timing	2020-2022

The switchgear, protection and controls of the 33 kV switchyard at the existing Timaru zone substation is nearing the end of its useful life. It is difficult to remove from service to maintain and protection grading is a challenge. This project will replace the equipment with modern circuit breakers and protection relays with suitable ratings and functionality.

TWIZEL GXP GEOGRAPHIC AREA



5.9.7. TWIZEL

OVERVIEW

Twizel is an expanding town that is popular as a holiday and tourism centre, being the nearest town to Mt Cook. It also serves as the main service centre in the Mackenzie Basin supporting agriculture, general engineering works, salmon processing and providing permanent accommodation for substantial numbers of Meridian Energy and Department of Conservation staff.

Near Twizel, Meridian Energy has generation assets at Lake Ohau, Lake Ruataniwha, and Lake Benmore.

NETWORK CONFIGURATION

Appendix A.6.7 describes the network configuration and shows the schematic diagram of the Twizel GXP and zone substation.

5.9.7.1. DEMAND FORECAST

Demand forecasts for the Twizel GXP, and regional zone substations are shown below with further details provided in Appendix A.5.

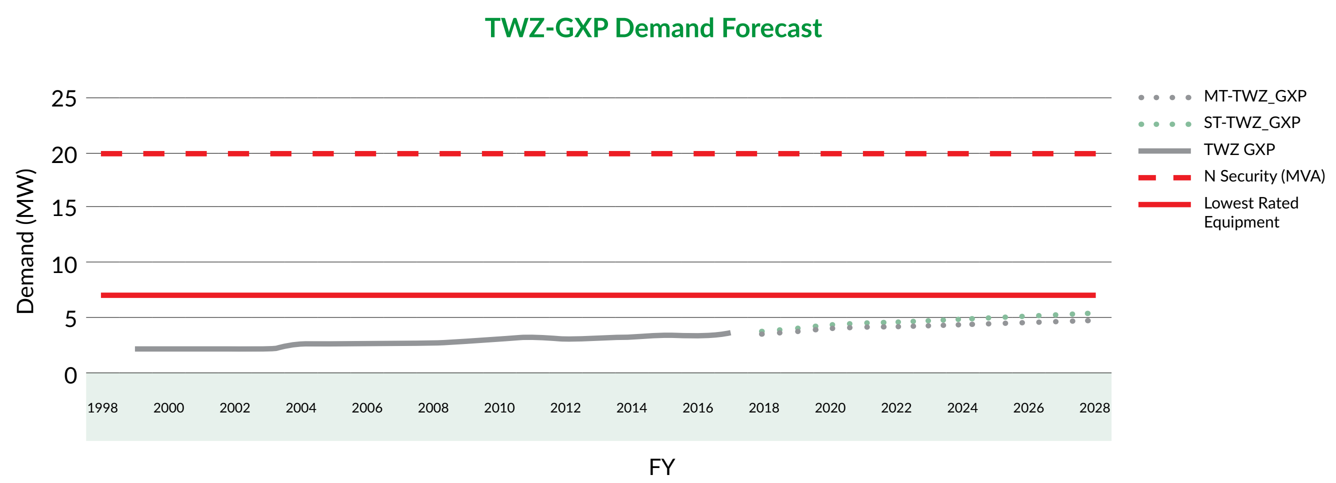


Figure 5.20 Twizel GXP demand forecast

Table 5.15 Twizel region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)
Twizel GXP*	20	-	6.86	3.49**	3.62	3.76	3.90
Twizel Village zone substation	6.25	-	6.86	3.49	3.62	3.76	3.90

* Transpower equipment (refer to www.transpower.co.nz).

** Twizel GXP forecasted values exclude Meridian Energy utilisation component.

There are no major step change load growth projects (that we know off).

The exception to that is if the Simons Pass load growth as discussed in the Tekapo region section above is supplied from Twizel. This is one of the options (least favourite) for the proposed increased Simons Pass load.

5.9.7.2. SECURITY OF SUPPLY

Table 5.16 Twizel region security of supply

Zone sub/load centre	Actual security level	Target security level	Shortfall from target
Twizel CBD	N-0.5	N-0.5	Limited 11 kV rings. We encourage consumers to self-manage their risk for outages for example, a Civil Defence emergency.
Twizel Rural	N	N	We encourage consumers to self-manage their risk for outages for example, a Civil Defence emergency.

5.9.7.3. EXISTING & FORECAST CONSTRAINTS

The Twizel zone substation has a transformer rated at 5/6.25 MVA. The transformer is fitted with an on-load tap changer (OLTC) which is important as the Twizel GXP 33 kV bus voltage changes with differing generation patterns; this keeps the 11 kV voltages stable.

Transpower's TWZ 33 kV GXP bus is run split, and is fed from two 20 MVA 220/33 kV OLTC transformers. The 33 kV bus was originally split as the 33/11 kV transformers are not able to withstand the full fault level. There is no 33 kV bus coupler or bus bar protection so running the bus tied would be problematic during a fault.

Our 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 supply transformer is lost or released, Transpower can easily tie the two bus halves to the remaining transformer.

The ripple injection plant at the Twizel GXP is used by Network Waitaki. Currently all ripple relays in the area are controlled via its time clock function. Future ripple injection plant development will be based on an economic analysis. With the introduction of smart meters, there may be alternative ways to provide demand side management.

There are limited low voltage reticulation ties in the Twizel township. This issue will be covered by the voltage regulation project discussed before.

5.9.7.4. MAJOR GROWTH AND SECURITY PROJECTS

Twizel zone substation asset replacements	
Estimated cost (concept)	$4.16m
Expected project timing	2020-2022

Most equipment at the Twizel zone substation is original and is near end of life. The land use requirements do not allow for upgrading of assets, only maintenance and like for like replacements. An engineering investigation will determine more exact detail on asset condition and the need (if any) for upgrades. From there, we will decide the course of action and timing for the Twizel zone substation work.


Irishman Creek
THE PRESS

ASSET MANAGEMENT PLAN // 2018

6. FLEET MANAGEMENT

6. FLEET MANAGEMENT

This chapter explains our approach to the life cycle management of our asset fleets. We provide further detail on this approach and how it will support our asset management objectives over the planning period.

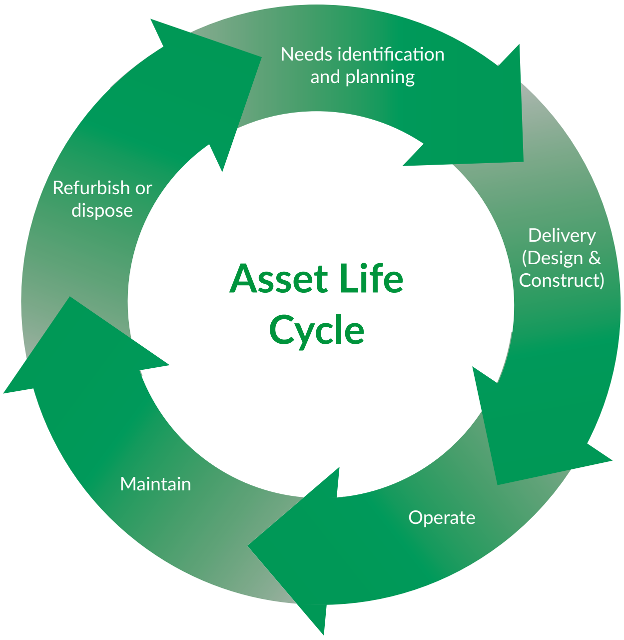


Figure 6.1 Asset management life cycle

Our fleet management approach includes the following five life cycle stages:

- Needs identification and planning
- Delivery (Design and Construct)
- Operate
- Maintain
- Refurbishment (Rehabilitating or modifying) or disposal

To support our five asset management lifecycle strategies we use a set of asset fleets which forms the basis of our day-to-day asset intervention strategies. We are in the process of developing a comprehensive set of asset fleet strategies that will set out our approach to managing individual fleet assets.

6.1 NETWORK-WIDE OPERATIONS

This chapter sets our approach to operating and maintaining our network assets. It describes our maintenance activities and sets out our forecast network Opex for the planning period (the expenditure directly associated with operating and maintaining our network). Good asset management requires balancing Opex and Capex to effectively manage assets over the long-term.

6.1.1 NETWORK CONTROL

6.1.1.1 CONTROL CENTRE

The prime role of network operations is to ensure a continuous supply of electricity to our customers and to maintain the network in a safe condition 24 hours a day, 7 days a week.

In our Control Centre network controllers monitor network status and load in real time, and take appropriate actions including planned and unplanned switching as well as load control to maintain supply through our network. We manage both the HV and LV networks in our Control Centre.

The Control Centre also performs the dispatch function, communicating with customers and our contractor to dispatch field staff where work is necessary to maintain or restore power supply.

6.1.1.2 SUPERVISORY CONTROL & DATA ACQUISITION

Our SCADA system is one of the primary tools used by the Control Centre to monitor network status and performance. This includes the loading, current and voltage at key locations, the position status (open/closed) of circuit breakers, switches and reclosers, as well as the status of a wide range of alarms such as power transformer oil temperature.

SCADA is also used to perform load control functions and to remotely operate circuit breakers and switches across the network. All these network control points are connected to our SCADA master station through telecommunications links. It is therefore imperative that our communications infrastructure is fit for purpose and has the necessary scalability to support increasing use of automation and real time monitoring.

Our SCADA system is continually developed and maintained by in-house SCADA specialists.

SCADA is managed as part of our secondary systems portfolio and is further discussed in section 6.8.

6.1.1.3 OUTAGE MANAGEMENT

Currently our network controllers handle outage related calls and liaise directly with customers. They also manage outage restoration efforts including tracking interruptions to customers, updating relevant outage information on our website as well as an interactive voice recording system. They carry out all these without the assistance of an integrated tool.

We have acquired the outage management system (OMS) module that can be integrated into the SCADA system and are currently implementing it. Once implemented (expected early in 2018) the OMS will become a core tool in managing and improving the Control Room workload. We expect significant improvement on our fault responsiveness.

6.1.1.4 RELEASE PLANNING

Release planning is another task that the Control Room manage on a daily basis. It is the process of isolating and releasing sections of the network to enable work to be carried out. Release requests are processed and coordinated to ensure that outage frequencies and durations are minimised while allowing us to effectively manage multiple works during individual outages to minimise disruption to customers.

6.1.2 SWITCHING

Switching is carried out to disconnect sections of the network for safety isolation to enable maintenance or new connections to be undertaken, or to restore supply in the event of a fault. We can switch devices that have been automated remotely from the control room while all other devices are switched manually. All our major zone substations are automated as well as approximately 75% of our reclosers. Planned upgrading of our communications systems in the planning period will provide the ability to control more devices in the Mackenzie basin and around Fairlie.

There are two principal switching methods – remote switching, which is done by the Control Room via SCADA, and field switching which is carried out by our contractor under the direction of the Control Room. Switching is prepared and written in the Control Room and then distributed to the contractor.

6.1.2.1 FUTURE OPPORTUNITIES

As part of improving our asset management approach we have identified a number of opportunities for operational systems development. These include:

- Automation of more field devices to improve operational responsiveness. These include more reclosers, remote control voltage regulation devices and remote telemetery fault passage indicators.
- Embedding OMS into daily operational routine, and then identifying enhancements that further improve its usability.
- Moving the switching process from the manual approach to an integrated electronic workflow. This will reduce processing time and will reduce the potential for switching errors.

6.1.2.2 SYSTEM INTERRUPTIONS AND EMERGENCIES

The system interruption and emergencies (SIE) portfolio entail reactive interventions in response to unplanned network events.

The main types of activities are as follows:

- First response: this involves the attendance of a Netcon fault person to assess the cause of an interruption, potential loss of supply, or safety risk. They assess the cause of the fault and may undertake switching or cut away a section of line in order to make safe or to alleviate the imminent risk of a network outage.
- Fault restoration: this is undertaken by the Netcon fault person and includes switching, fuse replacement or minor component repair in order to restore supply.
- Second response: this is where an initial fault response has restored supply but additional resource or equipment is required to restore the network to its normal state.

SIE work is prioritised and dispatched by the Control Room with the physical work carried out by our contractors. There is limited forward planning for SIE work other than ensuring there are sufficient resources on standby to respond to network faults. Failure to respond to SIE in a timely manner adversely affects the service provided to our customers and may pose risks to public safety.

At all times Netcon maintains sufficient resources for fault response. These are dispatched based on a number of factors such as potential safety risks and the need to maintain service levels for customers and to consistently meet contractual response times.

SIE work volume is driven by a variety of factors including asset condition, weather, environmental conditions, and our protection philosophies.

We have identified the high level objectives for our SIE activities as detailed in Table 6.1 below.

Table 6.1 SIE portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	Reduce fault response time to reduce the potential risk of public safety. Reduce safety hazards by prioritising safety driven faults.
Service levels	Minimise outage events and durations to support our regulatory reliability objectives.
Cost	Consider the use of alternative technology to reduce cost of reactive works and improve fault response times.
Community	Minimise landowner disruption when responding to network faults. Reduce fault restoration times to ensure we return supply to customers promptly.
Asset management capability	Consider better use of asset rating information to enhance load limits for greater network backfeed during faults.

To achieve these objectives we have set up the following key strategies below.

- Safety culture – hold regular safety days throughout the year to recognise the importance of safety. Also carry out field safety audits to ensure consistence approach to safety at work.
- Public awareness – continue to promote awareness of the risk and danger of electricity networks by educating the public and customers through regular community engagements.
- Resource management – ensure the availability of adequate resources and equipment to undertake SIE works, with relevant spares and materials available at all times.
- Systems enhancements – drive improvements through systems and tools available to the Control Room, including communication systems, SCADA and GIS. These will help to optimise network operations management and decision-making.

Our SIE expenditure forecast for the planning period is shown in Figure 6.2 below.

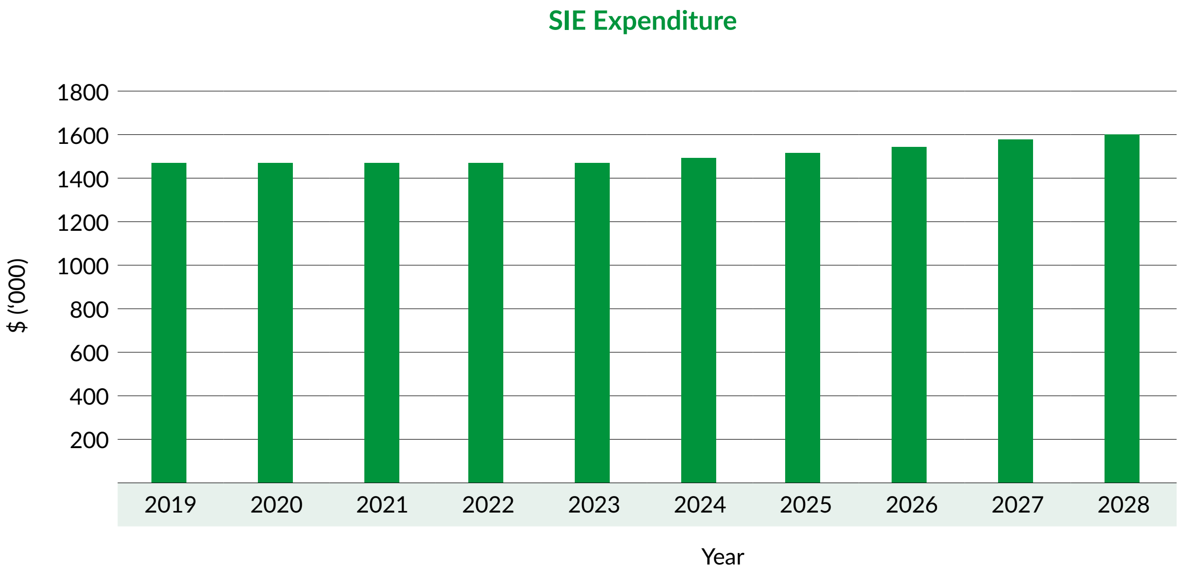


Figure 6.2 Forecast expenditure on SIE

We expect expenditure on SIE activities will remain relatively stable over the next 10 years as the impact of our vegetation management programme, increased asset renewals, and increased network automation takes effect.

6.1.2.3 FUTURE OPERATIONAL IMPROVEMENTS

As part of improving our asset management approach we have identified a number of opportunities for operational systems development. These include:

- Automation of more field devices to improve operational responsiveness. These include more reclosers, remote control voltage regulation devices and remote telemetered fault passage indicators.
- Embedding OMS into daily operational routine, and then identifying enhancements that further improve its usability.
- Moving the switching process from the manual approach to an integrated electronic workflow. This will reduce processing time and will reduce the potential for switching errors.
- Enhanced communications network – with the introduction of digital mobile radio we will extend our coverage, improve worker safety, response times and reliability.
- Field mobility solutions – will provide field staff with ease of access to asset data including standards, technical specifications, schedules and historical maintenance data, enabling more informed and timely decisions and actions.

6.1.3 MAINTENANCE STRATEGY

Maintenance is the care of assets to ensure they will provide their required capability in a safe and reliable manner from their commissioning through to their disposal, and can evolve as the condition and performance requirements of the assets change over time. Maintenance involves monitoring and managing the deterioration of an asset as it is operated over time or, in the case of a defect or failure, restoring the condition of the asset. Maintenance activities may also include modifications to an asset to improve performance and reliability.

We maintain the network to meet network operational and security requirements, taking into account safety, statutory compliance, sustainable operations and overall cost. These requirements are drawn from the shareholders, customers, regulators, and other stakeholders (such as the communities in which we operate).

We undertake network maintenance as:

- routine maintenance
- maintenance projects
- vegetation maintenance[22]

6.1.3.1 ROUTINE MAINTENANCE

Netcon, and other contractors carry out routine maintenance to keep assets in an appropriate condition, ensure that they operate as required, and to proactively manage failure risk. Routine maintenance also covers our response to failures and defects as these occur.

We classify routine maintenance within four work types:

- Preventive: Routine servicing or inspections to prevent failure or understand asset condition in line with an established schedule
- Corrective: Unforeseen maintenance to respond to a fault, or correct failed equipment and defects.
- Predictive: Maintenance performed based on known equipment condition, identified by remote monitoring or preventive maintenance inspections.
- Proactive: Improvements initiated by reliability or engineering analysis.

[22]Refer to section 6.1.5 for more detail.

The four work types are summarised below.

PREVENTIVE

Preventive maintenance is undertaken on a scheduled basis to ensure the continued safety and integrity of assets and to compile condition information for subsequent analysis and planning. It is generally our most regular asset intervention, so it is key to providing effective feedback to the overall asset management system. Preventive maintenance comprises three activities:

- Inspections: checks, patrols and testing to confirm safety and integrity of assets, assess fitness for service, and identify follow up work.
- Condition assessments: activities performed to monitor asset condition and provide systematic records for analysis.
- Servicing: routine tasks performed on the asset to ensure asset condition is maintained at an acceptable level, such as cleaning, adjustment, and lubrication.

CORRECTIVE

Corrective maintenance is undertaken to restore an asset to service, make it safe or secure, prevent imminent failure or address defects. The key distinguishing feature is that the work is initiated in response to unforeseen damage, degradation, or an operational failure. Corrective work is usually identified as a result of a fault or during preventive inspections. Failure to undertake urgent corrective work may result in reduced network reliability. Less urgent repairs are able to be scheduled at the appropriate time when access, resources and parts are available.

Corrective work activities include:

- Fault restoration: immediate response to a fault, or urgent repairs to equipment that has safety, environmental, or operational implications.
- Repairs: unforeseen work necessary to repair damage, prevent failure, or rapid degradation of equipment.
- Corrective Inspections: patrols or inspections used to check for public safety risks or conditions not directly related to the fault in the event of failure.

PREDICTIVE

Predictive maintenance is scheduled in response to condition-based inspection and monitoring programmes. This includes activities to replace components or repair assets in order to correct defects, wear and tear so as to return the asset to a defined standard that keeps it operational. Predictive maintenance also includes any additional targeted condition monitoring (such as thermographic imaging) to validate an existing condition assessment, or to predict likelihood of failure.

PROACTIVE

Proactive maintenance is improvement work initiated as a result of formal analysis and investigation by the engineering or reliability teams to reduce risk or provide an efficiency gain. Examples are asset modifications, one-off adjustments to scheduled activities, and condition monitoring programmes to provide more information or validate findings.

6.1.3.2 MAINTENANCE PROJECTS

'Maintenance project' is the term we use for a programme of works that addresses prevalent asset condition issues identified within routine maintenance. Maintenance projects will typically consist of programmes of small repairs or replacements of certain components of larger assets which are scheduled annually, distinguishing these works from routine maintenance. An example of where this might occur is where a common failure mode has been identified for an asset, leading to the need to replace or repair the same component on many assets.

These works also differ from capital projects because they involve replacing components of assets rather than the assets themselves (such as attachment points on a steel tower). Unlike refurbishment, which is capital expenditure (capex), these works would not be expected to extend the useful life of the larger asset but rather restore the asset to expected condition. These works are typically managed as planned projects and are budgeted for and scheduled in advance. Undertaking maintenance works as a formal project rather than as a large number of individual activities ensures the works programme is optimised and delivered more efficiently.

6.1.4 MAINTENANCE ACTIVITIES

We group our maintenance activities under two headings: Maintenance Specification and Maintenance Delivery.

- Maintenance Specification is the specification of the maintenance to be delivered, the skills and resources required; and the inventory practices to be applied. Critically, this involves the analysis of work history, asset and performance data; and the application of reliability processes to continually improve our maintenance and supply requirements. It is supported by our engineering team that ensure our maintenance approach takes into account all asset design, servicing and compliance requirements.
- Maintenance Delivery is the delivery of all maintenance work by qualified staff in a controlled manner that ensures the safety of all stakeholders, and the timely provision of all necessary materials and parts. This includes the medium-range planning and scheduling of the work programme, together with the detail planning of network and land access, resources and work scope for each job, all supporting execution of the work.

Maintenance Specification and Maintenance Delivery are interdependent within an improvement cycle:

- Maintenance Specification activities define our technical and quality requirements governing Maintenance Delivery (generally an AEL task)
- Maintenance Delivery is the planning and execution of the work (generally a contractor task)
- The outcomes of Maintenance Delivery (costs, equipment condition and performance, new work) are assessed within our Maintenance Specification activities to improve our maintenance requirements and provide advice to address reliability and performance risks (generally an AEL task).

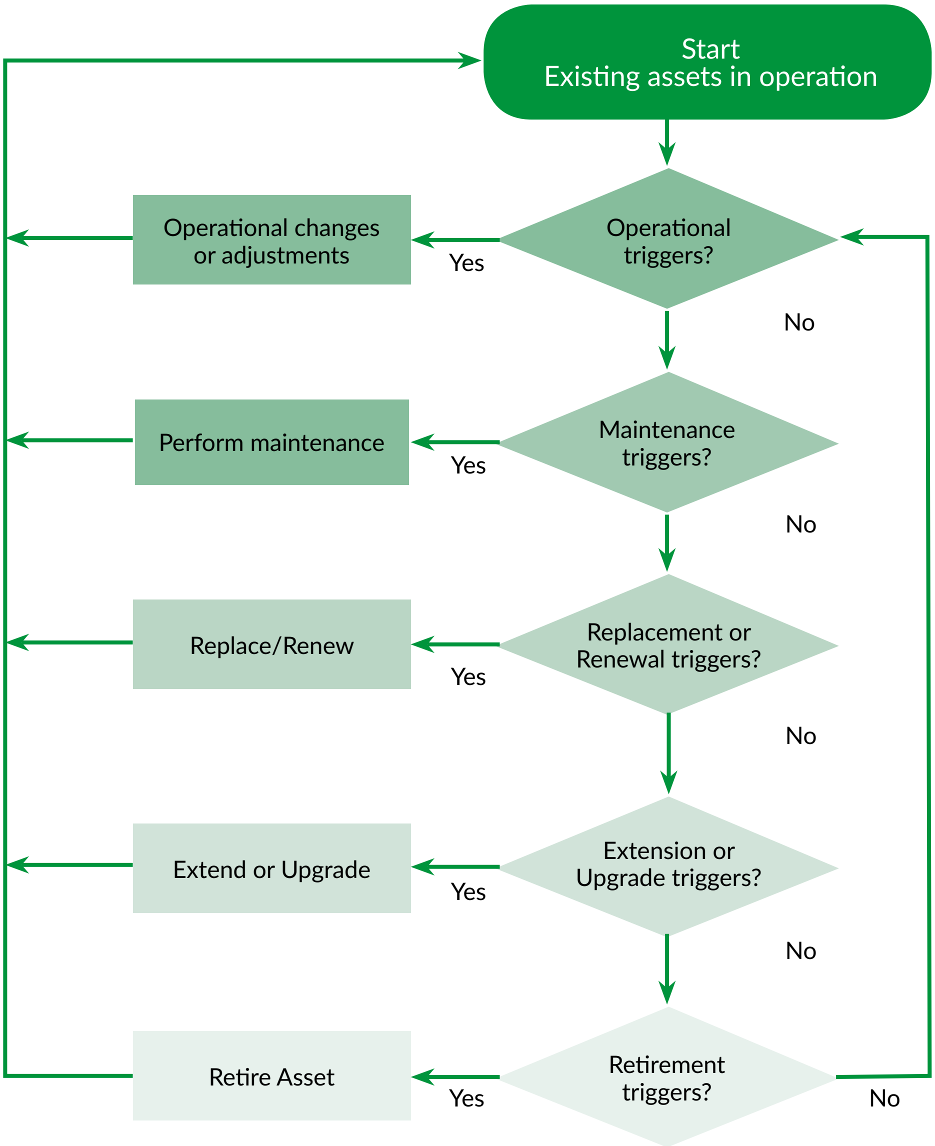


Figure 6.3 Maintenance life cycle

Table 6.2 Asset replacement & renewal strategic objectives

Asset maintenance objective	Portfolio Objective
Safety & environment	All work is done without any risk to the public, our staff and our contractors
Service levels	Minimise the outage time to customers as a result of planned maintenance activities Execute as much work as practicable under any single outage through appropriate planning
Cost	Ensure cost effective spending of budgets by reviewing work scope against costs, pricing of jobs before proceeding and monthly reporting of expense vs budgets
Community	Inform all consumers in a timely manner of any planned outages Minimise disruption to traffic and general consumer movements around maintenance sites
Asset management capability	Utilise our new EAM system to capture asset condition data, implement maintenance schedules for various asset types. Use EAM system to better schedule tasks in same areas and on same assets

6.1.5 VEGETATION MANAGEMENT

We undertake vegetation management to meet our safety obligations of keeping trees clear of overhead lines. This will in turn minimise vegetation related outages in support of our reliability targets like SAIDI and SAIFI. The appropriate planning and management of tree trimming is highly effective in reducing these outages.

6.1.5.1 KEY ACTIVITIES

The main activities undertaken in the vegetation management portfolio are:

- Surveys – periodic inspections of tree sites to determine whether trimming is required.
- Liaisons – interactions with landowners to identify those trees that require trimming or removal.
- Tree trimming – the physical works involved in trimming or removal of trees.

6.1.5.2 STRATEGIES AND OBJECTIVES

Vegetation management has a significant impact on network reliability and public safety. Prior to 2016 our network performance was adversely affected by an increasing number of interruptions caused by vegetation as shown in Figure 6.4.

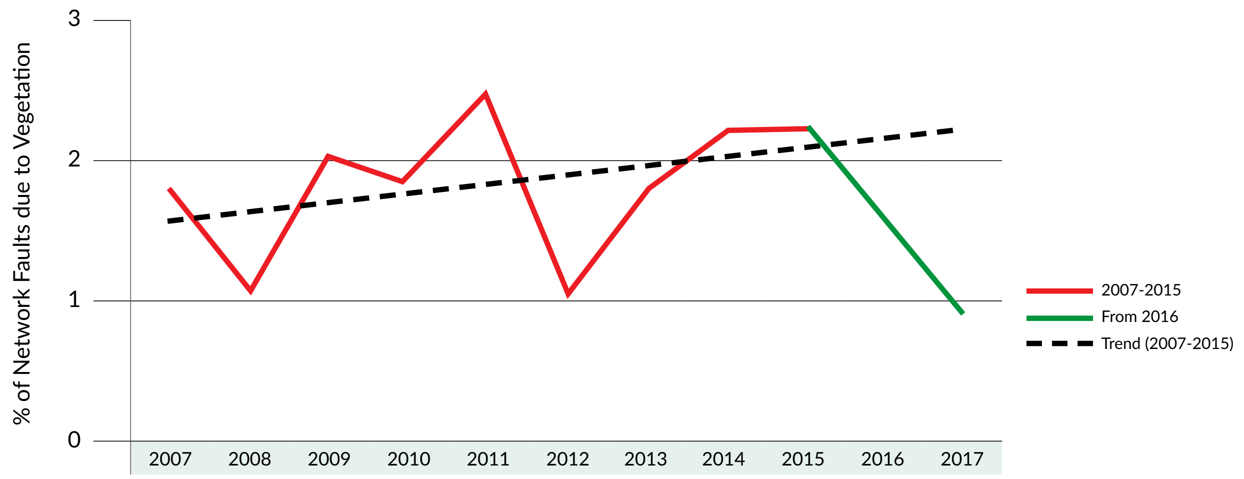


Figure 6.4 Vegetation related interruptions

Since 2016 we have placed an emphasis on vegetation management to help reduce unplanned outages by employing an in-house vegetation coordinator and increasing our vegetation opex budget. We also turned our approach to vegetation management from being reactive to proactive. This has seen considerable improvement in the fault trend due to vegetation.

To guide our strategy and activities during the planning period we have identified a number of high level objectives for our vegetation management activities.

Table 6.3 Vegetation management portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	Reduce the potential risk of incidents affecting tree owners undertaking trimming work to improve public safety. Have a risk based approach by prioritising higher risk trees.
Service levels	Ensure vegetation maintenance is undertaken by competent and network approved contractors and meets all H&S requirements.
Cost	Remain within budget and ensure a decline in operating costs by ensuring the appropriate parties are taking financial responsibility for any vegetation maintenance undertaken.
Community	Align vegetation maintenance schedules with other network maintenance to minimise disruption to customer supply. Have a proactive approach by providing advice, consultation and solutions for tree owners that aim to achieve the needs of all related parties.
Asset management capability	Better cataloguing of information using our asset management system and GIS, and using the systems to map and forecast tree growth rate.

To achieve the above objectives, our key strategies are:

- Cyclical schedules – implement routine vegetation maintenance schedules across our network to improve reliability.
- Risk-based proactive approach – routine surveying and scoping of our network for encroachment and high risk tree hazards and provide solutions and advice to all tree owners and contractors.
- Contractors engagement – actively engage with all our network approved contractors to ensure H&S and regulations compliance
- Public awareness – improve education to the public by supplying information regarding the risks of vegetation near power lines, unauthorised trimming/cutting of trees, planting advice and the responsibilities of tree owners.
- Record enhancements – develop robust record keeping of vegetation data to help identify problematic areas and assist in planning maintenance schedules.

6.1.5.3 FUTURE OPPORTUNITIES

The use of technology as well as collection of information is going to be important as we strive to maximise the value of our vegetation opex.

We plan to improve our infield surveying software, mapping systems and apply growth rates to assist in proactive planning and identify potential encroachment issues.

We will integrate our vegetation records within our asset management system and utilise the capabilities within the system for robust record keeping and data administration.

We will actively manage the relationships with tree owners to ensure financial responsibilities are met by the relevant parties.

6.1.5.4 VEGETATION MANAGEMENT OPEX FORECAST

Our vegetation management expenditure forecast for the planning period is shown in Figure 6.5.

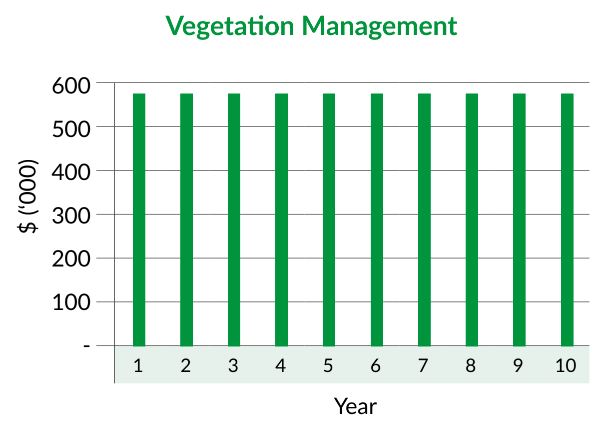


Figure 6.5 Vegetation management opex ($ real 2018)

In 2016 we recognised that our risk profile in relation to tree encroachment near our lines was higher than we would like. We will continue consolidation of the 2016 and 2017 effort and build on the momentum we have achieved to date.

6.2 OVERHEAD STRUCTURES

6.2.1 OVERVIEW

This chapter describes our overhead structure portfolio and summarises the fleet management plans for these assets. An overview of the assets fleets are presented including population, age and condition. Forecast expenditure for replacements and renewal for the planning period is also detailed. The portfolio includes the following asset fleets:

- Hardwood poles
- Softwood poles
- Concrete poles

PORTFOLIO SUMMARY

Investment in overhead structures for the planning period is forecast at $4 M over the planning period. This portfolio accounts for 56% of the renewals expenditure over the planning period.

In January 2014, a review of softwood poles sourced from fast growing immature forests concluded that they would no longer be used on the network. Following the review, the estimated life span of existing softwood poles has been reduced from 40 - 50 years to 25 - 50 years. Any adjustment of estimated life will be based on condition assessment. A small percentage of earlier generation softwood poles, installed between 1985 and 1986, have performed much better as they were sourced from mature forests with more dense timber.

Figure 6.6 Wood pole left and concrete pole right

A review of our mass reinforced concrete pole making factory in 2013 determined that it was no longer sustainable. The factory was subsequently closed and all new concrete poles are pre-stressed and purchased from industry compliant suppliers. The remaining fleet of mass reinforced poles will be managed until end of their safe and useful life.

All new pre-stressed poles have a superior pole top strength compared to the mass reinforced poles. These have performed well to date. A small percentage of other brands of pre-stressed poles are included in the fleet and have also given good service.

We have a large percentage of naturally durable and treated hardwood poles which have performed well over the last 70 years. The introduction of steel poles is being considered initially for larger double circuit structures and as a cost-effective alternative to hardwood in snow areas.

6.2.2 PORTFOLIO OBJECTIVES

Table 6.4 Overhead structures portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	Safety in Design considered for all structures. Replace structures using condition information before failure. Responsible disposal of obsolete poles and components. Ensure hardwood crossarms are sourced from sustainable forests.
Service levels	Continual refinement of condition based renewal techniques to improve feeder reliability (SAIDI & SAIFI) and end of life predictions.
Cost	Provide cost effective designs, construction, operational and disposal techniques for all structures and lines.
Community	Minimise planned outages to customers by coordinating replacement with other works. Minimise landowner disruption when undertaking renewal work.
Asset management capability	Provide adequate and appropriate resources to effectively design, build, operate, maintain and support a safe and reliable overhead network.

6.2.3 POPULATION AND AGE STATISTICS

The number of and type of poles are summarised in Table 6.5 below.

Table 6.5 Number and estimated life of pole types

Type	Number	% of total	Estimated life (years)
Hardwood	13,983	34	40-60
Softwood	5332	12	25-50
Concrete	22,299	54	60-100

As illustrated in Figure 6.7, the majority of the 33 kV subtransmission network was installed in the 1960's and 1980's to meet the growing demand from the rural network. The growth spike of 1996 was due to the construction of the 30 MVA dairy factory at Clandeboye. In 2004, a new line was constructed to supply Rangitata substation. In 2013, a new double circuit 110 kV designed line, energised at 33 kV, was constructed to supply the ODL dairy factory at Glenavy.

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

The majority of poles, including softwood, hardwood, and concrete, are more than 35 years old.

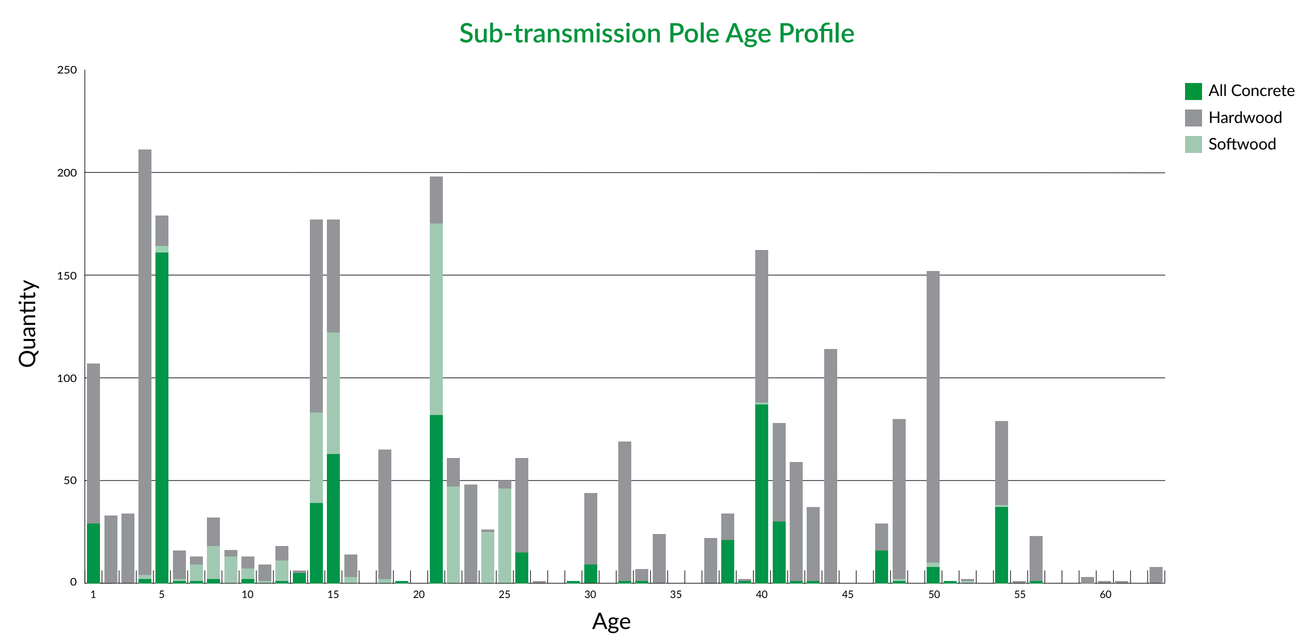


Figure 6.7 Subtransmission pole age profile

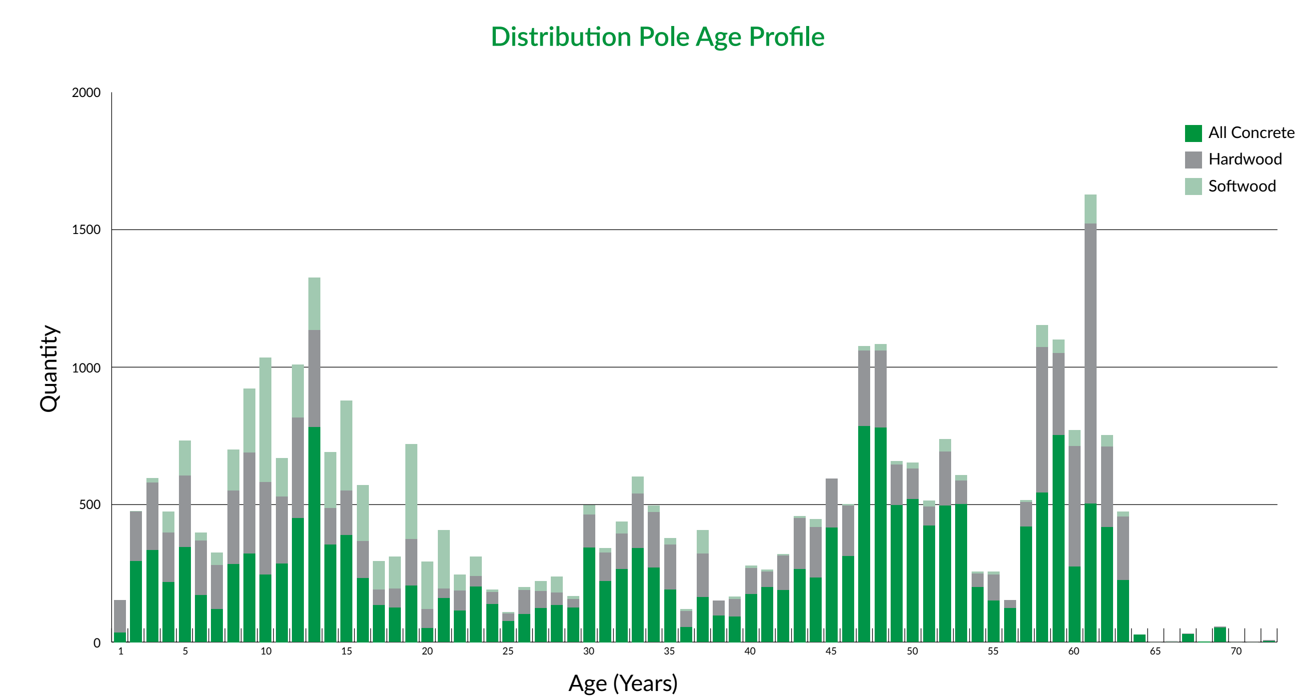


Figure 6.8 Distribution pole age profile

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

Existing overhead infrastructure will only be undergrounded if:

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

Existing overhead lines will be maintained with like-for-like overhead components.

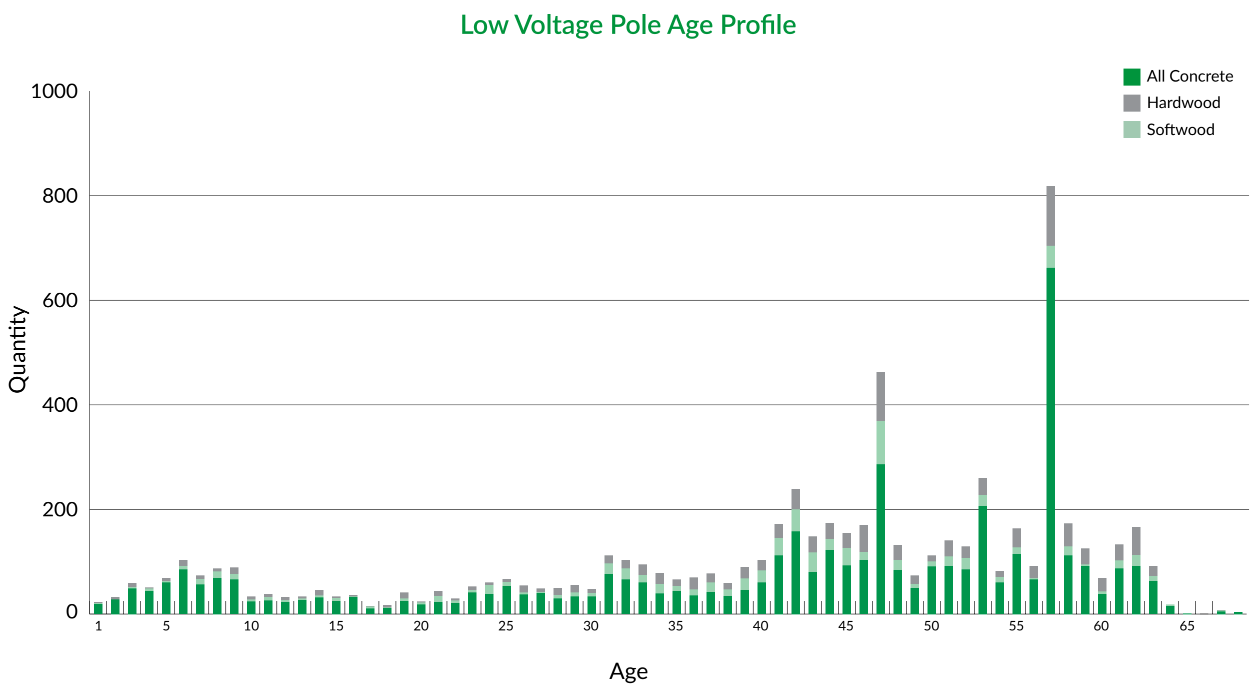


Figure 6.9 Low voltage pole age profile

6.2.4 CONDITION, PERFORMANCE AND RISKS

The challenges relating to the condition and performance of poles include:

- Risk of premature softwood pole failure, due to brown rot or structural degradation. We inspect poles prior to their 25th year in service and more frequently towards end of life. We liaise with other networks that have experienced similar issues to discuss appropriate strategies. We no longer use softwood poles and a replacement programme is in place.
- Mass reinforced concrete poles have generally performed well: There are few signs of premature condition deterioration and failures are mostly due to vehicles, imbalanced snow loads, inherently weak conductor breakage or third party influences such as trees. A very small percentage has failed due to chloride or carbonation penetration. These penetration failures could be attributed to poor quality concrete and/or workmanship on any given day of manufacture.
- The pre-stressed concrete pole fleet is relatively young and to date they have performed well. They are lighter, offer superior strength and have a longer life expectancy. Some of the longer length poles however are susceptible to damage during fitting and erecting due to deflection from their own mass.
- Naturally durable and treated hardwood poles have performed well but require routine inspection below ground after their 25th year in service. This inspection identifies 99% of threatening defects however we have had the odd failure below the 500 mm deep inspection zone.
- Hardwood crossarms have a life of 30 to 40 years and are therefore generally replaced before the poles' end of life. Crossarms are replaced when condition assessment determines that they are no longer capable of supporting serviceability loads.

6.2.5 DESIGN AND CONSTRUCT

Our legacy network was designed using first principals of solid engineering practice and that continues today through a combination of "in-house" design spread sheets, continually developed since 1995, and more recently with proprietary software, CATAN, which supports the requirements of AS/NZS 7000:2016 Overhead Line Design and its related standards. The principals of safety in design were introduced in 2016.

99.9% of all overhead line design is done in-house and the remaining 0.1% has been contracted to consultants familiar with our standards. Although we have solid design standards and construction methods these are scheduled to be formally documented in the near future using the PowerCo Standards documentation template.

Netcon carries out the majority of our overhead line work to ensure consistent construction methods and standards.

33 kV sub-transmission lines are high priority due to their potential impact on network reliability. Subtransmission lines are designed and built to the highest standards and, in the case of Clandeboye and Pareora, have duplicate circuits to provide security of supply. The remaining lines are single 33 kV circuits.

The 11 kV distribution lines and cables are typically open-ringed in the Timaru CBD and industrial areas, as well as in the denser loaded suburban and rural, areas. LV lines and cables also have interconnection in densely populated urban areas, but are typically short spur lines in other areas.

Historically, in the days of dry farming and cropping, lightly loaded rural areas were arranged as a single spur overhead line. With load density growing markedly due to dairying and irrigation, rural lines are built or upgraded to be open-ringed, providing alternative supply routes where possible.

6.2.6 OPERATE AND MAINTAIN

Our condition assessment programme is designed to identify and replace defect poles before failure and we aim to carry out:

- A detailed inspection of every pole, after 25 years' service, on a rolling 10 year basis, covering 10% of the route length each year.
- The condition assessment data is reviewed and a replacement solution implemented.
- Crossarm condition based renewals are carried out during pole replacement.

Our condition assessment programme was introduced in 1985 and initially focused on areas predominantly reticulated with hardwood poles installed between 1955 and 1961 with approximately 10% to 20% of poles being replaced after each inspection. Initial inspections of urban areas also focused on wood poles however a full condition assessment programme for urban reticulation, including all small townships, has now been introduced.

Each timber pole is visually inspected over its length above ground and below ground to a depth of 500 mm via excavation. The excavation inspects the integrity of the timber in the zone of soil bacteria activity and involves the removal of sapwood to measure the remaining healthy timber. The diameter of the healthy heartwood is used to determine the remaining serviceability life of the pole, based on the ultimate design load being met for a further 10 years. A GoPro camera fixed atop a hot stick is used to scrutinise pole top component condition.

Our cyclic 10 year condition based renewal process ensures a level of confidence in the condition of the oldest remaining poles and effectively staggers the capital required for end of life replacement. The aim of inspection is to identify and document all components that may not be able to support serviceability and ultimate design loads, and to comply with clearances of New Zealand Electrical Code of Practice for Electrical Safe Distances 2001.

A two coloured tag system is used to identify suspect poles. A standard red tag identifies poles at risk of failure under serviceability loads, requiring replacement within three months of inspection. A standard yellow tag is used to indicate that a pole may not be capable of supporting ultimate design loads beyond the next 10 years. Applying a safety factor of two, the yellow tagged poles are replaced within five years of inspection. Poles found to be incapable of supporting ultimate design loads are replaced in conjunction with red tag poles.

In an attempt to remove human subjectivity, new technology for wood pole assessment is being trialled to establish the best combination of available tools. Although still in infancy, none of the technological solutions evaluated today have instilled confidence in the ability to assess pole condition accurately. This is a work in progress.

Our defects system data is received from the field and/or public and corrective maintenance or asset replacement is scheduled based on the severity of the defect priority. Our five defect priorities codes range from urgent (correction within 48 hours) to trivial (routine maintenance cycle).

The sub-transmission lines built in recent years are due for inspection and maintenance in the 25th year of service, unless condition suggests otherwise. Our subtransmission line inspections are prioritised based on age and recent performance.

6.2.7 RENEW OR DISPOSE

Concrete poles have an estimated life of 60 to 100 years, softwood poles 25 to 50 years, and hardwood poles 40 to 60 years. New softwood poles and the reuse of softwood poles is banned on the network.

A programme to replace the existing fleet of softwood poles over a number of years has been prioritised as follows:

- Conjoint 33 kV and 11 kV lines
- 33 kV lines
- 11 kV lines with heavy conductor
- All others during refurbishment, unless required earlier.

Very few concrete pole replacements are expected due to age in the next 30 years. Hardwood poles are replaced at end of life however in some cases where a busy pole has failed at ground level, but still in good condition atop, it is reinforced with a galvanised steel splint to extend its useful life.

An age based replacement estimate would indicate that, on average, 260 to 330 poles would need replacing each year. However, adequate maintenance of lines renders the age-based replacement philosophy unrealistic. We use actual condition to inform the replacement of wooden poles.

We have approximately 30,000 poles over 25 years' old so to inspect these over ten years requires 3,000 to be inspected annually. Inspections have been increased to achieve this target.

Disposal of treated wood poles is expected to pose an issue until an environmentally friendly method can be found. Present disposal consists of them being sold to public to recycle or given to non-profit organisations for community projects.

Damaged concrete poles are either gifted to landowners or crushed and recycled by local contractors.

Untreated hardwood is sold for fire wood or recycling.

6.3 OVERHEAD CONDUCTORS

6.3.1 OVERVIEW

Our overhead conductor fleet consists of copper (Cu), galvanised steel (Fe), steel reinforced aluminium (ACSR), all aluminium (AAC) and more recently all aluminium alloy (AAAC). In the 1950's some of the ACSR conductor was ungreased however we do not know the full extent or location of this conductor. Most areas of its use have been discovered over time and these are monitored closely for corrosion. Early identification is critical and some non-greased conductors have been replaced already.

All legacy single strand 13mm^2 copper and steel 11 kV conductors have been replaced. While copper conductor in general has given good service, smaller copper conductor is inherently more susceptible to tensile failures than ACSR and have been stretched over repeated storm events. These have been identified and their replacement will be ongoing for the foreseeable future.

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

Early storm event data reports did not distinguish between conductor failure and joint failure which lead us to believe that some conductors had begun failing. This however was not the case as it was discovered that most reported conductor failures were in fact joints failing through a mixture of poor design, incorrect application and incorrect size.

The circuit kilometres of all overhead network lines, by three-phase, single-phase, and single wire earth return (SWER), are shown in Table 6.7

PORTFOLIO SUMMARY

Investment in overhead conductor for the planning period is rolled into the pole structures budgets above. We are currently only replacing short sections of weaker conductor that has failed due to extreme weather events causing vegetation to be blown into the lines.

6.3.2 PORTFOLIO OBJECTIVES

Our overhead conductor portfolio objectives are summarised in Table 6.6 below.

Table 6.6 Overhead conductor portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	No injuries to the public or contractors as a result from conductor failure. No property damage as a result from conductor failure.
Service levels	Reduced SAIDI and SAIFI by timely conditioned based renewals. Continual refinement of end of life predictions techniques.
Cost	Provide cost effective designs, construction, operational and disposal techniques for all lines. Establish a balance between electrical conductivity and mechanical strength in conductor choice.
Community	Minimise planned outages to customers by coordinating replacement with other works. Minimise landowner disruption when undertaking renewal work.
Asset management capability	Provide adequate and appropriate resources to effectively design, build, operate, maintain and support a safe and reliable overhead network.

6.3.3 POPULATION AND AGE STATISTICS

Table 6.7 details the overhead conductor length for various voltage levels and type of construction, while Table 6.8 details the conductor quantities in the various types on our network.

Table 6.7 Overhead circuit length in km

Voltage	3-phase	1-phase
110 kV	24	N/A
33 kV	243	0
22 kV	28	116
11 kV	1937	830
400 V	226	139

[22] High frequency and low amplitude vibration caused by smooth (non-turbulent) winds (3-24 km/h)

Table 6.8 Overhead Conductor type length and percentage of total

Type	Length (km)	% of total
AAAC	34	1
AAC	94	2
ACSR	2766	70
Cu	373	10
*other	672	17

* This conductor information exists on paper records only but will be loaded into our AMS as part of a planned asset audit project.

6.3.4 CONDITION, PERFORMANCE AND RISKS

Early ACSR conductors used an ungreased galvanised steel core and are susceptible to premature corrosion in the comparatively hostile coastal environment. The condition of this type of conductor is closely monitored, especially around joints and terminations.

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

Some areas of the network were reticulated using smooth body ACSR conductor strung at 40% of its ultimate tensile strength due to designs incorporating many large spans. Some of this conductor has been subject to Aeolian vibration[22] over its life time however this has proven to not have been damaging.

Corrosion of ACSR conductors has also become prevalent under the older type parallel groove (PG) clamps, resulting in a small number of premature conductor failures under the clamp. PG clamps are now routinely replaced with modern equivalent connectors during maintenance.

Some ungreased conductors installed in coastal environments between Studholme and Glenavy are showing signs of corrosion. Due to capacity demands, a large amount of the rural overhead network has been rebuilt in recent years, resulting in the replacement of the older, inherently weak and corrosion susceptible conductors. Replacement continues.

The network's all aluminium conductors (AAC) and all aluminium alloy (AAAC) conductors are in good condition.

A new industry wide initiative is looking to provide a more informative method of identification for predicting remaining life of conductor.

6.3.5 DESIGN AND CONSTRUCT

Our overhead lines are designed to the AS/NZS 7000:2016 Overhead Line Design standard.

Choosing a conductor wire size and material involves considering electrical, mechanical, environmental and economic factors. Our new lines are constructed with modern ACSR and AAAC conductors with superior strength. The modern design has greatly reduced the structure and pole damage associated with the tensile failures of older inherently weak conductors.

The requirements of AS/NZS 7000:2016 Overhead Line Design is more conservative with its span lengths for distribution lines due to increased design snow and ice load requirements. Designs to this standard will increase the life of conductors and reduce the tensile failure damage resulting in more resilient networks. High strength conductors such as Magpie, Wolf, Cub, Snipe, etc. installed on large spans and in snow prone areas are closely monitored.

Distribution ties have recently been approved on our network to secure conductors to insulators. Advantages include speed and ease of installation, overall cost reduction, a resiliency to permit longitudinal displacement over the insulator and reduced radio interference voltage (RIV) issues.

The use of helicopters for stringing operations is becoming increasingly more common, due to the ease and speed of construction, and it reduces the impact on landowners and the wider public (e.g. when working alongside a roadway).

6.3.6 OPERATE AND MAINTAIN

Condition assessment of conductors is non-intrusive and is carried out in conjunction with structure inspections on a 10 year cyclic programme. Intrusive inspections are performed, through conductor sampling, only when required to support renewal decisions.

Old parallel grove clamp connectors promote corrosion between the conductor and clamp. These are routinely replaced as mentioned earlier.

Conductors with broken strands are repaired with wrap on sleeves or armour rods to prevent further damage.

Out of sag spans are routinely re-pulled to prevent conductor clashing.

6.3.7 RENEW OR DISPOSE

The dairy and irrigation industry has driven renewal of many old and less resilient conductors, especially at network extremities.

By overlaying storm damage data maps we have been able to identify areas of repeat conductor damage. This evidence allows us to prioritise conductor renewals based on an assessment of risk, security of supply, economic impact and safety.

We expect overhead conductor replacements to remain fairly constant over the next 10 years and then start increasing beyond the current planning period.

Old conductor is generally sold for scrap with a selection of older types, in good condition, retained for emergency repairs.

6.4 UNDERGROUND CABLES

6.4.1 OVERVIEW

This chapter describes our underground cables portfolio and summarises our associated fleet management plan. The portfolio includes three fleets:

- Subtransmission cables
- Distribution cables
- LV cables

This section provides an overview of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

6.4.1.1. SUBTRANSMISSION CABLES:

The subtransmission cable fleet predominantly operates at 33 kV, though we also classify our 11 kV Timaru supply cables to the CBD as subtransmission cables because of their relative importance and mesh configuration compared with the open ringmain 11 kV feeder cables. The assets include cables, joints and pole terminations. The two types of cable used are XLPE and PILC.

6.4.1.2. DISTRIBUTION CABLES:

The distribution fleet operates at 11 kV. The main assets within the fleet are cables, joints and pole terminations. We have two main types of cable insulation in the network at the distribution level – XLPE and PILC.

PILC has been used internationally for over 100 years and manufactured in New Zealand since the early 1950's. PILC uses paper insulating layers impregnated with non-draining insulating oil. The cable is generally encased by an extruded waterproof lead sheath covered in wrapped and tar impregnated fibre material, PVC, or polyethylene. PILC cables have a good performance record in the industry.

The first XLPE cables were installed in our network after the mid-1970's. Consequently our XLPE cables are of the recent technology and their construction, operational integrity and safety features are improved over the earlier generation of XLPE cables. All cables installed on our network today, including repairs to existing PILC cables, are XLPE.

6.4.1.3. LV CABLES:

The LV cable fleet operates at below 1 kV (230/400 V). The main assets within the fleet are cables, link boxes, LV cabinets, in-ground boxes, and pillar boxes.

The number of consumers on a particular LV network section depends on the load density. The distance from the distribution transformer to the furthest consumer is usually limited to around 400 metres.

Customer service lines connect to our LV cable network by a cable from a pillar box usually located on the property boundary. The integrity of pillar boxes is a key public safety concern. We have a variety of different styles and materials installed on our network.

PORTFOLIO SUMMARY

Investment in underground cables for the planning period is forecast at $ 17.22 M over the planning period. This includes asset relocations (i.e. overhead to underground conversions), replacement and renewals, and growth projects. This portfolio accounts for 13% of the total expenditure over the planning period.

6.4.2 UNDERGROUND CABLE PORTFOLIO OBJECTIVES

Table 6.9 below summarises our underground cable portfolio objectives.

Table 6.9 Underground cable portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	No public safety incidents by coming into contact with our cable network. Manage all excavating on our network via beforeUDig process.
Service levels	Minimise interruptions to consumers when performing asset management activities on our cable network. Keep consumers informed of planned outages. Continue program to construct mobile generation connection points across our cable network.
Cost	Ensure investment is appropriate through risk assessment and risk reduction. Plan and resource maintenance activities to minimise plant outages.
Community	Appropriate traffic management to minimise disruption in event of cable repair in roadways. Ensure access to private properties when trenching in roadways.
Asset management capability	Load and populate asset data on our AMS. Develop fleet maintenance strategy and program and implement on AMS. Continue staff training on various asset types through Engineering NZ and EEA.

6.4.3 POPULATION AND AGE STATISTICS

Our network contains over 600 km of underground cabling of both XLPE and PILC varieties. The cables supply power at 230/400 V, 11 kV and, to a lesser extent, 33 kV.

The quantity of cable for various voltage levels on our network is shown in Table 6.10 below.

Table 6.10 Underground cable circuit lengths

Voltage	Length (km)	% of total
33 kV	41.4	5.45
22 kV	4.5	0.6
11 kV	366	48.22
6.6 kV	7.23	0.96
400 V	340	44.78

The ODV handbook gives us a lifespan of approximately 70 years for PILC cables. We assume a life of approximately 40 years for XLPE cables installed prior to 1986, and a life of 50 years for those installed afterwards. The difference is due to advances in XLPE materials and construction made in 1986 that led to XLPE cables having a significant longer service life. It should be noted that our lifespan assumptions are conservative as the areas in which the bulk of our cables are laid are considerably drier than those for which the ODV handbook figures were calculated.

All 33 kV cables on our network are less than 38 years old. The age profile of our subtransmission cables is shown in Figure 6.10.

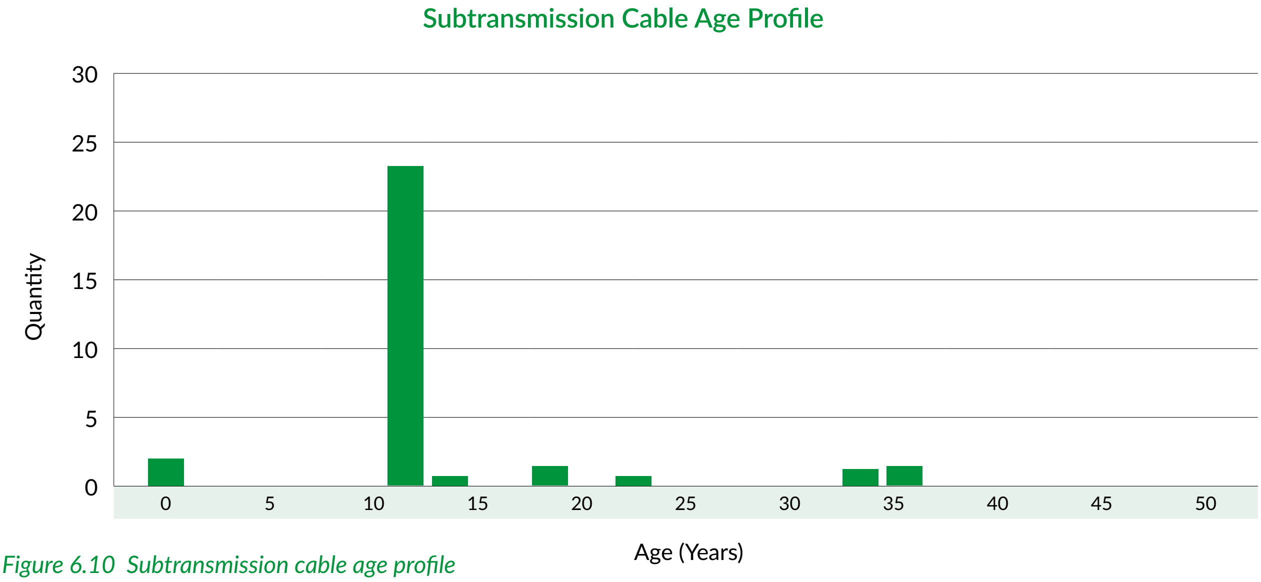


Figure 6.10 Subtransmission cable age profile

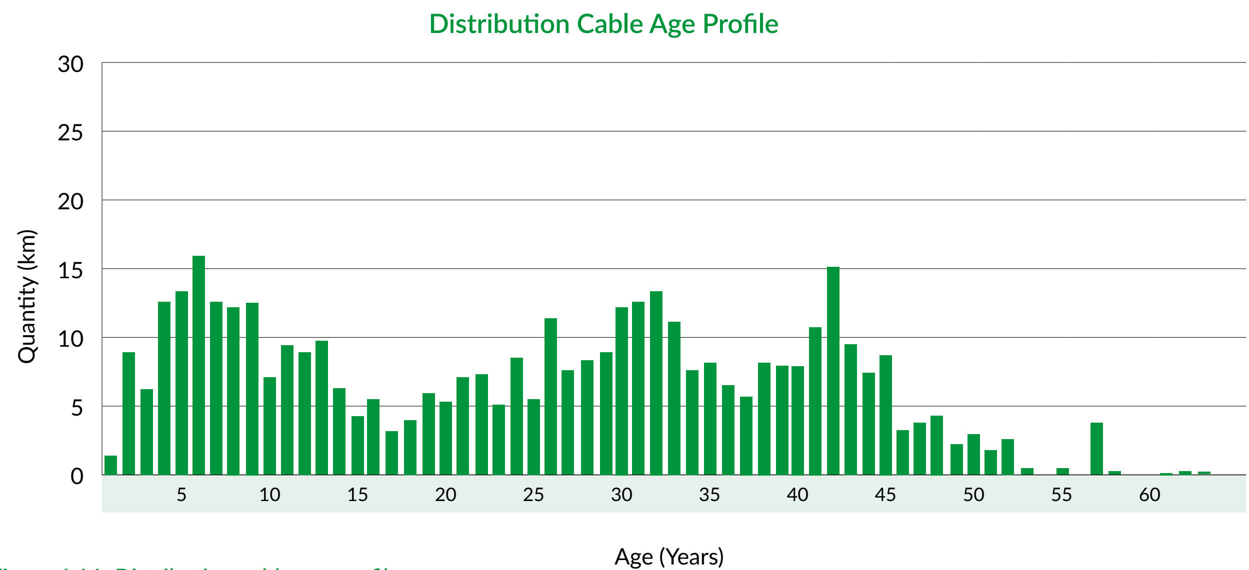


Figure 6.11 Distribution cable age profile

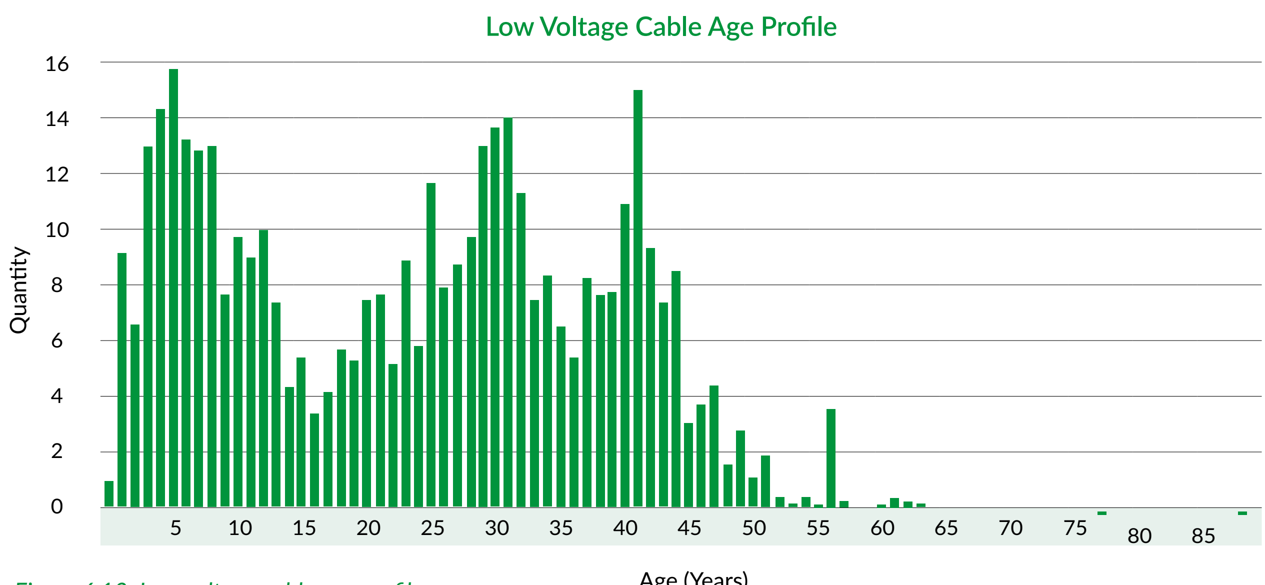


Figure 6.12 Low voltage cable age profile

The HV and LV distribution networks include distribution boxes, oil switches, and ring main units. Most of these assets have been installed in the last 20 to 40 years (the estimated life is 60 to 80 years). Fifty percent of the underground 11 kV distribution network was installed in the last 25 years. The majority of the oldest cables are of PILC construction, which has a 70 year life.

The more recently installed cables (20 to 40 year age group) are of PVC sheathed, XLPE core insulation construction, and have an expected service life of 55 years.

The LV cables are predominantly PVC and, more recently, XLPE insulated, with a small quantity of older LV PILC cables.

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

6.4.4 CONDITION, PERFORMANCE AND RISKS

Our cable fleet is generally in a good condition. We continue to monitor the trends in cable condition assessment and use the knowledge gleaned from premature failures to reassess the remaining population's future performance.

LV PVC cables are susceptible to water ingress through the PVC and joints to the cable conductor and subsequent corrosion of the aluminium conductor. XLPE insulation is impervious to water but water may still enter at joints if not adequately sealed.

The LV cable circuits in the Timaru CBD include main reticulation cables buried in the street feeding a legacy conduit system attached to the fronts of buildings. Our approach is to maintain the LV conduit system above ground unless the building is to be demolished. The cost to replace the LV conduit system with an underground system is relatively high and not always economically justifiable. The seismic status of the CBD buildings may result in either strengthening or replacement of many of these buildings. We will replace the conduit system in stages as these building changes occur.

In the past, major Timaru CBD subtransmission 11 kV cables were offline partial discharge tested every five years to monitor condition. Recent joint failures to the sub-transmission cables have caused us to increase the very low frequency (VLF) partial discharge to a biennial test as a means to determine change in cable joint condition. Our cable faults tend to be due to joint failure, unfavourable installation conditions, or foreign body or mechanical interference. We have not found a quantitative analysis method to accurately predict the occurrence of faults.

6.4.5 DESIGN AND CONSTRUCT

Standardisation assists us in our ongoing management of this asset fleet. Using standard designs and equipment, we are able to ensure cost effective capital and maintenance expenditure.

The standard cable sizes we use on out network are listed in Table 6.11.

Table 6.11 Standard cable sizes

Type	Description
Sub-transmission	11 kV and 33 kV, 1C and 3C, Al: 300 mm², 400 mm²; 33 kV 1C Al: 1200 mm².
Distribution	11 kV, 1C and 3 C, Al: 35 mm², 95 mm², 185 mm², 300 mm², 400 mm²
Reticulation	LV neutral screen, 95 mm², 185 mm², and 300 mm²

These cables are aluminium with XLPE insulation. Multicore and single core cables are used according to the applications. Other conductor sizes may be used, such as when additional current rating is required.

6.4.6 OPERATE AND MAINTAIN

Cables themselves are generally maintenance free as they are buried for most of their length. We perform inspections and diagnostic testing on above ground components such as terminations every thirty months. We routinely inspect above ground exposed sections of cable and associated terminations to identify any condition degradation (UV is a major cause of degradation).

We operate a system to log 11 kV and 33 kV cable faults, building up a history of statistical data to monitor cable performance and record failure modes. The average number of faults in 11 kV underground cables over the last six years (not including cables damaged by human error) has been two and a half, with the greatest number in one year being four and the least being zero.

For our more important cables (i.e. 33 kV and 11 kV subtransmission cables) we have adopted VLF partial discharge testing as the preferred HV cable test technique to avoid treeing[23] of the XLPE insulation from HVDC test techniques. For commissioning of cables we use megger tests. For cable and joint fault finding we will use HVDC test equipment on a lower voltage setting to locate the fault to avoid over stressing the healthy cable sections.

LV distribution boxes and link boxes are the largest maintenance item for the LV reticulation, particularly the older painted steel and concrete boxes. The newer boxes made with galvanised steel internal frames and ultra-tough UV stabilised polyethylene plastic covers are relatively low maintenance and consequently are expected to have longer life.

6.4.7 RENEW OR DISPOSE

Cable faults most commonly occur due to third party interference such as digging. When cables or their protection have degraded or been damaged we undertake repairs to avoid a fault occurring. Corrective actions for cables include:

- Replacement of damaged cable termination mechanical protection on poles.
- Replacement of cable terminations due to degradation.
- Fault repairs due to third party damage or other cable faults.

Spare cable and associated cable jointing equipment is held in our Washdyke depot critical spares store to enable fault

[23]A damaging process due to partial discharges and progresses through the stressed dielectric insulation, in a path resembling the branches of a tree. Treeing of solid high-voltage cable insulation is a common breakdown mechanism and source of electrical faults in underground power cables.

repairs to be undertaken.

Our renewal approach for cables is to replace based on condition or age.

Cable insulation generally degrades over time, with the largest influences being operating temperatures and exposure to UV (which in turn influences the life of insulation, screens and cable finishes). Condition assessment, inspections and multiple failures can indicate a cable in poor condition and these cables are replaced.

Planning of cable replacement due to asset health and end of life should take cognisance of the load requirements for the cable to be replaced. For example, a number of our oldest Timaru CBD cables are reaching their capacity limits owing to their relatively small size compared with our present day size standards. One or more of these may need to be replaced or supplemented before 2030 for reasons of capacity. New technology uptake may influence the planning of cable replacements in future.

A programme was commenced in 2014/15 to replace all the subsurface Lucy boxes within the CBD's main LV underground reticulation system with above ground mounted distribution/link boxes to eliminate operational constraints posed by the deterioration of the Lucy boxes. These box replacements will also allow easier access to the underground and other distribution substations for refurbishment, maintenance and operation. To date we have completed 14 replacements and have planned ten replacement per annum for the first five years of the planning period.

6.5 ZONE SUBSTATIONS

6.5.1 OVERVIEW

This portfolio includes the following six main fleets, plus other zone substation assets:

- power transformers
- indoor switchgear
- outdoor switchgear
- buildings
- load control plant
- protection relays

The chapter provides an overview of asset population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

PORTFOLIO SUMMARY

During the planning period we expect to invest $13.14 M in zone substation renewals. This portfolio accounts for 17.6% of the total renewals budget for the planning period. This investment is needed for:

- New assets due to load growth
- Renewal of assets due to load growth
- Renew aged assets
- Manage safety risk

A zone substation typically takes supply at a voltage level and either steps up or down to distribution or sub-transmission levels through power transformers. Switching stations without power transformers are also included in our fleet of zone substations. Prudent management of these assets is essential to ensure safe and reliable operation.

6.5.2 PORTFOLIO OBJECTIVES

The portfolio objectives for this fleet are given in Table 6.12.

Table 6.12 Zone substation portfolio objectives.

Asset management objective	Portfolio objective
Safety & environment	Safety incorporated in all designs. No lost time incidents due to arc flash faults. Maintain SF6 register and log gas quantities during maintenance.
Service levels	Continual refinement of condition based maintenance to maximise reliability (SAIDI & SAIFI). Provide mobile substation connection points at all appropriate zone substations.
Cost	Provide cost effective designs, construction, operational and disposal. Ensure fit for purpose infrastructure based on risk mitigation and supply security standard.
Community	Minimise planned outages to customers by coordinating replacement with other works. Consult with respect to aesthetic impact of new designs. Use low noise designs for replacement transformers.
Asset management capability	Provide adequate and appropriate resources to effectively design, build, operate, maintain and support a safe and reliable zone substation fleet.

6.5.3 ZONE SUBSTATION TRANSFORMER FLEET MANAGEMENT

6.5.3.1 FLEET OVERVIEW

Zone substation transformers, with capacities ranging from 0.6 to 25 MVA, transform power supply from one voltage level to another, generally 33/11 kV (or 11/33 kV), but some are 110/33/11 kV and 11/22 kV. The zone substation transformers are all three phase units, with the exception of one case, where three single phase units are installed. Figure 6.13 shows a typical zone substation power transformer.

Figure 6.13 Zone substation transformer – Cooneys Road substation

6.5.3.2 POPULATION AND AGE STATISTICS

There are 26 zone substation transformers on our network, of which 23 are 33/11 kV units (with three connected as step-up 11/33 kV), one is 110/33/11 kV and two are 11/22 kV. The Table 6.13 summarises our population of transformers by rating. Of the 26 units listed one is a 33/11 kV, 3 MVA spare, one is a 33/11 kV, 5/6.25/9 MVA spare and one is a 33/11 kV, 9 MVA mobile substation.

Table 6.13 Zone substation transformer population

Rating	Number	% of total
< 5 MVA	4	15
≥ 5 and < 9 MVA	5	19
≥ 9 and < 20 MVA	8	31
≥ 20 MVA	9	35
Total	26	

Our zone transformers age profile is shown in Figure 6.14. 65% of our zone substation transformers are 20 years old or younger. The rest are between 35 and 57 years old. The single installation (comprising three single phase units, counted as a single unit in this list) is in excess of 50 years old and is located at the Balmoral substation. This substation of 600 kVA capacity supplies mainly rural households and some irrigation load. This transformer is due for replacement three phase unit next year in response to load growth in the area.

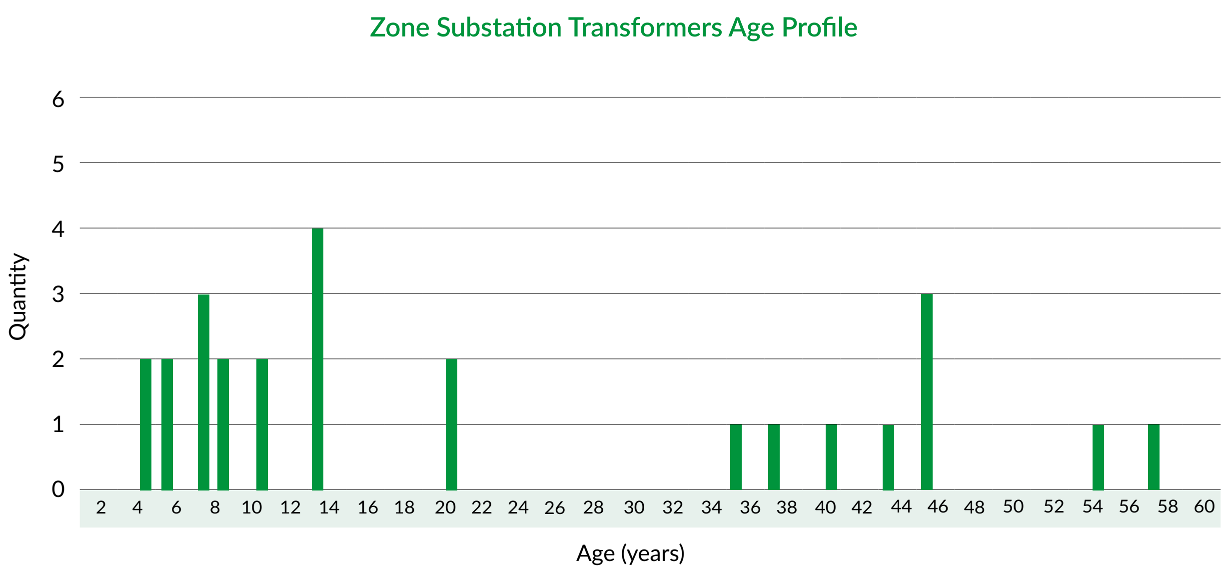


Figure 6.14 Zone substation transformer age profile

6.5.3.3 CONDITION, PERFORMANCE AND RISKS

The zone substation transformer population is in good condition. The older transformers are typically at sites with low yearly average loads and have been refurbished mid-life to ensure they reach expected service life of at least 50 years.

Power transformer failures are relatively rare. The main causes are likely to be manufacturing defects or occasional on-load tap changer failures due to mechanical issues.

6.5.3.4 DESIGN AND CONSTRUCT

We have a good design specification for power transformers which together with design reviews ensures we get quality assets from our suppliers. We procure our transformers from a small group of transformer manufacturers.

To ensure good operational flexibility across the network we now order transformers in standard sizes. However, from time to time we have purchased transformers that are not in our standard range.

Standard sizes for 33/11 kV transformers are:

- 9/15 MVA
- 20 MVA
- 19/25 MVA

The result of having standard sizes is that sometimes a replacement power transformer is larger than the load forecast suggests is required. However this is offset by the ability to use spares across a number of units.

We specify all our transformers with low noise emission irrespective of the installation location. This is to ensure the community impact by noise is minimised, even if a transformer is moved to a different substation.

6.5.3.5 OPERATE AND MAINTAIN

Power transformers and their associated ancillaries (such as tap changers) undergo routine inspections and maintenance to ensure their continued safe and reliable operation. These routine tasks are summarised in the table below.

Table 6.14 Power transformer maintenance and inspection tasks

Maintenance and inspection task	Frequency
General visual inspection of insulating systems, cooling, bushing and insulators, tap changer compartment, foundations and other ancillaries.	1 monthly
Routine planned maintenance: Service dehydrating breathers. External paintwork touch-ups. Automatic voltage regulator operation checks. Buchholz gas check. Acoustic emission, thermal imaging and external partial discharge diagnostic tests, and oil sampling for laboratory dissolved gas analysis tests.	1 yearly
Routine planned maintenance: transformer, tap-changer, and mechanical/electrical auxiliaries. Insulation and winding resistance tests.	4 yearly and as required by manufacturers' manuals and counters

Where possible, we recycle transformers between sites to ensure full utilisation of the life of the transformers. Some units have been refurbished before redeployment to ensure continued satisfactory operation to end of life. The relatively high cost of refurbishment limits the degree of refurbishment and whether it is undertaken. The decision to proceed with a refurbishment is taken on a case-by-case basis.

MOBILE SUBSTATION

Many of our rural zone substations have a single power transformer supply. Some maintenance or planned replacement work requires an outage to the communities supplied by these substations. Over the past few years it has become increasingly difficult to justify outages due to increased focus on reliability.

Our mobile substation is used to eliminate the need for outages or, in some cases, reduce the extent of the outages. It is also used to improve reliability of supply during emergencies. Our mobile substation, rated at 9 MVA, was procured in 2014.

6.5.3.6 RENEW OR DISPOSE

We have defined a set of triggers for our zone substation assets renewal. These are listed in Table 6.15.

Table 6.15 Triggers for renewal of assets

Asset	Trigger
Fences and enclosures	Condition based replacement or maintenance unless costs exceed replacement.
Buildings	Maintenance costs exceed replacement.
Bus work and conductors, 33 kV switchgear, transformer, 11 kV switchgear	Condition based replacement or maintenance costs exceed replacement. Load growth. Supply security.
Cable terminations, cable boxes, joints	Condition or age based replacement.
Batteries and chargers	Age or condition, whichever is sooner .
Instrumentation	Maintenance costs exceed replacement or equipment obsolete or age limit reached.

A power transformer is usually replaced because it is in poor condition or the required load forecast exceeds its rating. As part of our planning we ensure that a new power transformer can serve its expected future load at the zone substation. However, significant increase in load due to irrigation has required some transformers to be replaced prior to and of life. The replaced transformers have usually been recycled on the network and used at other substations.

Most of our power transformer renewals have been triggered by load growth rather than the transformer condition.

Zone substation supply security requirements can be a reason for additional transformers. In this planning period, we are intending to add two power transformers in two zone substations to improve supply security.

Power transformer replacements are among the larger projects undertaken within a zone substation. For delivery and cost efficiency we often coordinate other zone substation works (such as outdoor switchgear replacements) with transformer projects.

To help with long-term forecasting of power transformer replacements we are developing a condition-based asset health model. Asset health indices provide a more accurate assessment of remaining reliable service life than age alone.

Our power transformer asset health model will be based on work by the EEA Asset Health Indicator (AHI) Guide, influenced by IEC 60599:2015 and Cigre TB 296, and supported by our experience and asset information. Condition indicators that will be used in the model include dissolved gas analysis (DGA), general condition, age, typical degradation path, bushings condition, external factors (such as coastal salt air) tank condition and known issues.

6.5.4 INDOOR SWITCHGEAR FLEET MANAGEMENT

6.5.4.1 FLEET OVERVIEW

Indoor switchgear comprises individual switchgear panels assembled into a switchboard. These contain circuit breakers, isolation switches, busbars along with associated insulation and metering equipment. They also contain protection and control devices along with their associated current and voltage transformers.

Indoor switchgear is generally considered to be more reliable than outdoor switchgear and also has a smaller footprint than outdoor installations.

33 kV ZONE SUBSTATION INDOOR SWITCHGEAR

There are six 33 kV CB panels that are indoor type. These were installed in 2011 at Pareora substation (PAR).

Each 33 kV CB panel has two SF_6 insulated chambers, one containing an off load isolating/earthing switch and the other a vacuum circuit breaker (CB).

These six 33 kV indoor vacuum/SF_6 CB panels have a manufacturer's assurance of 40 years maintenance free operation. Routine inspection and monitoring only is required for the life of the switchgear.

11 kV ZONE SUBSTATION INDOOR SWITCHGEAR

There are 159 11 kV indoor switchgear units making up 16 indoor 11 kV switchboards in our zone substations. The majority of our 11 kV zone substation indoor switchgear are vacuum circuit breakers (VCBs), 17 are of the bulk oil variety. The vacuum type CBs are used for all new installations and where bulk oil CBs are being replaced.

Figure 6.15 11kV Indoor switchboard at North Street substation

6.5.4.2 POPULATION AND AGE STATISTICS

The table below summarises our indoor switchgear population by type and number of circuit breakers and switchboards.

Table 6.16 Indoor switchgear population by type

Type	Circuit breakers	Switchboards
Oil	17	3
Vacuum	142 +1*	12
Vacuum in SF_6	6*	1
Total	166	16

*33kV VCB panels.

The following two figures show the age profiles for indoor type 33 kV and 11 kV circuit breakers respectively.

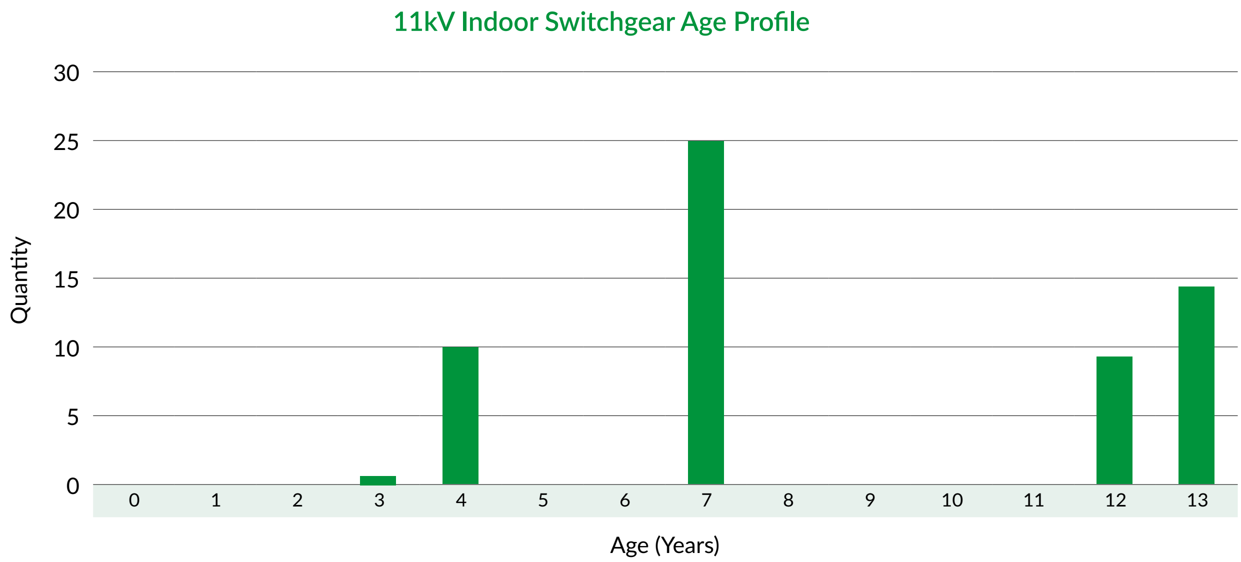


Figure 6.16 11 kV indoor switchgear age profile

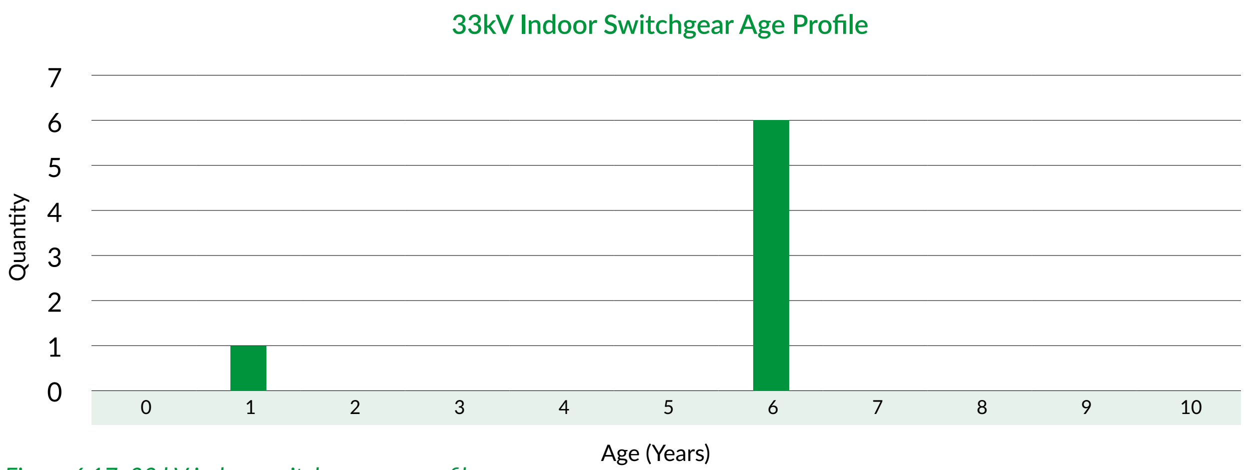


Figure 6.17 33 kV indoor switchgear age profile

6.5.4.3 CONDITION, PERFORMANCE AND RISKS

INDOOR SWITCHGEAR ASSET HEALTH

For indoor switchgear we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely and the switchgear should be replaced. The switchgear health is primarily evaluated using asset age, typical expected lives and condition assessments.

Table 6.17 Condition assessments of zone substation indoor switchgear

Table 5: Condition Assessments of Zone Substation Indoor Switchgear

Zone Substation:	Voltage kV:	Number of Bank:	Age: years:	Remaining Life (RL) (years)*:	Age based Condition:	AMP "G" Condition:	Est. EEA Guide AEL AHI - AHI from Condition	Est. EEA Guide AEL AHI - AHI from Non-condition	Summary of EEA AHIs:	Overall condition assessment:
Bell's Pond	11	T1	0	60	Excellent	Excellent	H5	H5	Excellent	Excellent
Bell's Pond	11	T2	7	53	Excellent	Excellent	H5	H5	Excellent	Excellent
Clandeboye No.1	11	T1	20	40	Excellent	Excellent	H5	H5	Excellent	Excellent
Clandeboye No.1	11	T2	20	40	Excellent	Excellent	H5	H5	Excellent	Excellent
Clandeboye No.2	11	T1	13	47	Excellent	Excellent	H5	H5	Excellent	Excellent
Clandeboye No.2	11	T2	13	47	Excellent	Excellent	H5	H5	Excellent	Excellent
Cooney's Road	11	T1	3	57	Excellent	Excellent	H5	H5	Excellent	Excellent
Fairlie	11	T1	3	57	Excellent	Excellent	H5	H5	Excellent	Excellent
Grasmere Street	11	Bus A	5	55	Excellent	Excellent	H5	H5	Excellent	Excellent
Grasmere Street	11	Bus B	5	55	Excellent	Excellent	H5	H5	Excellent	Excellent
Hunt Street	11	Bus A	33	27	Good	Good	H4	H4	Good	Good
Hunt Street	11	Bus B	33	27	Good	Good	H4	H4	Good	Good
Mobile Substation (AMS)	33	T1	3	57	Excellent	Excellent	H5	H5	Excellent	Excellent
Mobile Substation (AMS)	11	T1	3	57	Excellent	Excellent	H5	H5	Excellent	Excellent
North Street	11	Bus A	6	54	Excellent	Excellent	H5	H5	Excellent	Excellent
North Street	11	Bus B	6	54	Excellent	Excellent	H4	H5	Good	Good
Pareora	33	T1	6	54	Excellent	Excellent	H5	H5	Excellent	Excellent
Pareora	11	T1	9	51	Excellent	Excellent	H5	H5	Excellent	Excellent
Pareora	33	T2	6	54	Excellent	Excellent	H5	H5	Excellent	Excellent
Pareora	11	T2	9	51	Excellent	Excellent	H5	H5	Excellent	Excellent
Pleasant Point	11	T1	11	49	Excellent	Excellent	H5	H5	Excellent	Excellent
Rangitata	11	T1	13	47	Excellent	Excellent	H5	H5	Good	Good
Rangitata	11	T2	6	54	Excellent	Excellent	H5	H5	Excellent	Excellent
Studholme	11	T1	12	48	Excellent	Excellent	H4	H5	Good	Good
Studholme	11	T2	12	48	Excellent	Excellent	H4	H5	Good	Good
Tekapo	11	T1	33	27	Good	Good	H4	H3	Fair	Fair
Tekapo	11	T2	33	27	Good	Good	H4	H3	Fair	Fair
Temuka	11	T1	11	49	Excellent	Excellent	H5	H5	Excellent	Excellent
Temuka	11	T2	11	49	Excellent	Excellent	H5	H5	Excellent	Excellent
Twizel	11	T1	65	-5	Fair*	Fair	H4	H2	Fair	Fair
Twizel	11	T2	65	-5	Fair*	Fair	H4	H2	Fair	Fair
Unwin Hut	11	T1	40	20	Good	Fair	H5	H3	Fair	Fair

OUR ASSET HEALTH INDICES (AHI), AS USED IN THIS TABLE, ARE:

- Excellent = estimated to have between 60 and 40 years life remaining.
- Good = estimated to have between 40 and 20 years of life remaining.
- Fair = estimated to have between 20 and 5 years of life remaining.

About 10% of our indoor switchgear requires replacement over the next 10 years.

ARC FLASH RISK

Arc flash risk is a considerable safety concern for our indoor switchgear fleet. Assessment was undertaken for our 11 kV and 33 kV indoor switchboards to determine their risk levels.

We mitigate this risk through one of three approaches:

- Switching is carried out remotely while ensuring the switchroom is clear of personnel.
- Ensuring personnel working close to the switchboard wear appropriate arc flash rated PPE gear.
- Remove the entire switchboard from service to perform maintenance.

These solutions do not completely eliminate arc flash risks.

All newly installed switchboards have arc flash detection systems, arc containment and venting. We have installed various arc flash retrofits (including blast proof doors, arc flash detection systems and arc venting) on a number of existing switchboards to mitigate arc flash risk. It is planned to introduce arc flash detection on an existing oil circuit breaker (OCB) switchboard in the immediate future. We are continually evaluating arc-flash mitigation options on our remaining switchboards that are classified as relatively high risk to safety due to arc-flash risks.

Our equipment class standards classify indoor switchgear as class A equipment as its function is critical to the reliable operation of the network.

Before a new type of switchgear can be used on the network, it must undergo a detailed evaluation process to ensure the equipment is fit for purpose on our network.

6.5.4.4 OPERATE AND MAINTAIN

Indoor switchgear undergoes routine inspections and maintenance to ensure their continued safe and reliable operation. Our various routine maintenance tasks are summarised in Table 6.18. The detailed regime for each asset is set out in our maintenance standard.

Table 6.18 Indoor switchgear maintenance and inspection tasks

Maintenance and inspection task	Frequency
General visual inspection of circuit breakers, cabinets and panels.	Monthly
Operational tests on circuit breakers not operated in last 12 months. Condition-test switchgear including thermal, PD and acoustic emission scan.	1 yearly
Insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. SF_6 gas pressure checks.	4 yearly
Vacuum circuit breaker diagnostic tests (e.g. HV withstand).	As required
Switchboard partial discharge test.	As required

6.5.4.5 RENEW OR DISPOSE

Indoor switchgear renewal decisions are based upon several factors that include:

- switchgear condition (condition of the circuit breakers, busbars and other associated ancillaries),
- known reliability issues,
- future requirements due to growth, such as fault levels and load,
- fault level interrupting and load carrying capacity,
- arc flash risk mitigation priority, and
- changes in maintenance requirements.

CRITICALITY AND RESILIENCE

We consider these factors holistically along with the criticality of the zone substation when we determine the optimum time for replacement.

Table 6.19 Summary of indoor switchgear renewal approach

Summary of indoor switchgear renewal approach	
Renewal trigger.	Proactive condition monitoring.
Forecasting approach.	Age and arc flash levels.
Cost estimation.	Desktop project estimates.

RENEWALS FORECASTING

The remaining indoor circuit breakers are generally in good to excellent condition and will not need replacing within this planning period, unless triggered by factors other than condition assessment.

New zone substation projects typically use indoor switchgear because it provides better value with regard to performance and whole-of-life cost. For urban substations, switchgear is installed in buildings that visually integrate into the surrounding neighbourhood to minimise visual impact.

6.5.5 OUTDOOR SWITCHGEAR FLEET MANAGEMENT

6.5.5.1 FLEET OVERVIEW

Our zone substations outdoor switchgear fleet comprises several asset types including outdoor circuit breakers, air break (ABS) and load break (LBS) switches, fuses, links, and reclosers.

Outdoor switchgear is primarily used to control, protect and isolate electrical circuits in the same manner as indoor switchgear. It de-energises equipment and provides isolation points so our contractors can access equipment to carry out maintenance or emergency repairs.

The majority of AEL Zone substation outdoor switchgear assets are either 11 kV or 33 kV rated with small historical amount of 22 kV and recently installed 110 kV switchgear.

There are three 110 kV rated SF_6 outdoor circuit breakers (CB) on our network. Two of them are currently operated at 33 kV.

There are 21 33 kV outdoor circuit breakers and reclosers (switchgear) within our zone substations majority of which are oil and vacuum in oil while recent 33 kV switchgear is SF_6

insulated. 33 kV CBs typically protect zone transformers and/or sub-transmission lines.

There are only nine 11 kV outdoor circuit breakers and reclosers in our zone substations as the majority of our 11 kV zone substation switchgear comprises of indoor installations.

Table 6.20 Outdoor zone substation switchgear population by type and voltage rating

Voltage rating	Circuit breakers	Reclosers	RMU	ABS/LBS	Links	Fuses	Other
11 kV	1	5	4	36	31	17	-
22 kV	-	1	-	2	4	-	-
33 kV	5	16	-	49	26	5	-
110 kV	3	-	-	2	-	-	2

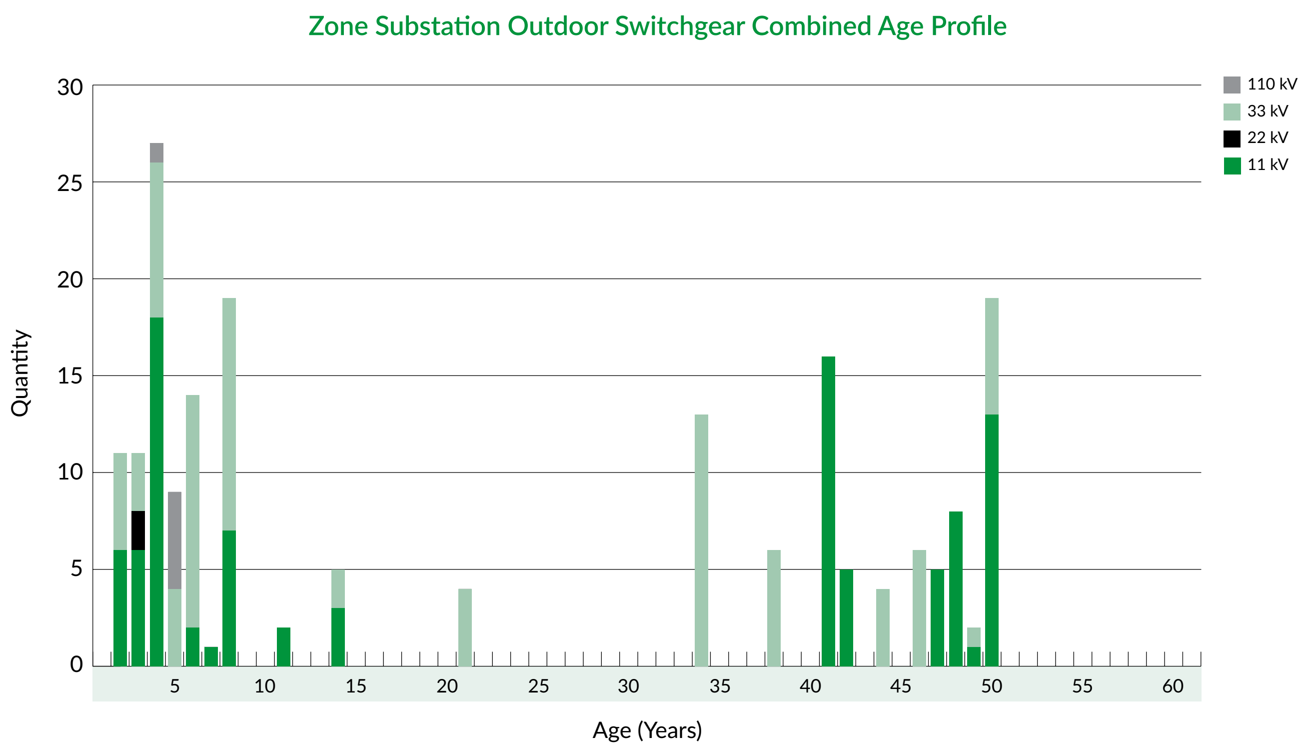


Figure 6.18 Zone Substation outdoor switchgear combined age profile

6.5.5.2 POPULATION AND AGE STATISTIC

The majority of outdoor zone substation circuit breakers are oil or vacuum in oil (41.6%), with the remainder being SF_6 (30.6%) and vacuum (27.8%) interrupter based (in air or solid dielectric).

Although unlikely, oil CB failures can result in explosions and fire. Oil CBs are mainly 33 kV rated and represented in the higher age group of our outdoor switchgear. Oil CBs will be phased out over time and replaced by either vacuum or SF_6 based circuit breakers.

Table 6.21 summarises our population of outdoor circuit breakers broken down by interrupter type.

Table 6.21 Outdoor switchgear population by insulation media type and voltage rating

Type	110 kV CBs	33 kV CBs	22 kV CBs	11 kV CBs
Oil	-	9	1	-
Vacuum in Oil	-	4	-	-
Vacuum	-	4	-	6
SF_6	3	4	-	4
Total	3	21	2	10

Note: This table includes Circuit breakers, Reclosers and RMUs

We generally expect outdoor switchgear assets to require replacement at an age of 45 to 55 years. Assets that are close to their ODV expected life are monitored closely and replacements will be based on condition. A large number of ABS/LBS, links and other outdoor switchgear has been maintained and refurbished over the past decade (i.e. ABS/LBS mechanism maintained and insulators replaced) in order to extend asset life.

6.5.5.3 CONDITION, PERFORMANCE AND RISKS

Oil-based circuit breakers carry additional risks compared to their modern equivalents. A higher frequency of operations and energy of switching increases the likelihood of failure. To minimise this failure risk oil circuit breakers are serviced after they have performed a specified number of switching operations. The number is determined based on the type of circuit breaker and the fault current breaking energy.

For outdoor switchgear we define end-of-life when the asset can no longer be relied upon to operate reliably and safely. The switchgear condition is primarily evaluated using asset age, typical expected life and condition assessment.

6.5.5.4 DESIGN AND CONSTRUCT

Outdoor switchgear is classified as class A equipment and undergoes a detailed evaluation process to ensure any new equipment is fit for purpose on our network.

For outdoor 33 kV circuit breakers replacement, our current standard asset is a live tank SF_6 insulated unit. SF_6 circuit breakers are the current industry standard for HV outdoor applications. However, we are continually monitoring developments in the industry to ensure the best value for the network is achieved.

6.5.5.5 OPERATE AND MAINTAIN

Outdoor switchgear undergoes routine maintenance to ensure safe and reliable operation. We undertake routine maintenance on OCBs on the basis of the number and severity of circuit breaker operations for fault current clearance to mitigate against failure modes associated with excess duty.

Our various routine maintenance tasks are summarised in Table 6.22. The detailed regime for each asset is set out in our Outdoor Switchgear Maintenance Standard.

Table 6.22 Outdoor switchgear maintenance and inspection tasks

Maintenance and inspection task	Frequency
General visual inspection of circuit breakers, ABSs and reclosers.	Monthly
Operational tests on CBs not operated in last 12 months. Condition-test circuit breakers including thermal, PD and acoustic emission scan.	1 yearly
Circuit breaker insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. ABS thermal scan. Recloser thermal and oil insulation tests.	4 yearly
ABS service of contacts and mechanism.	As required
Vacuum and SF_6 recloser checks and insulation tests.	As required
Replace oil (if relevant). Contacts checked and resistance measured.	Operations based

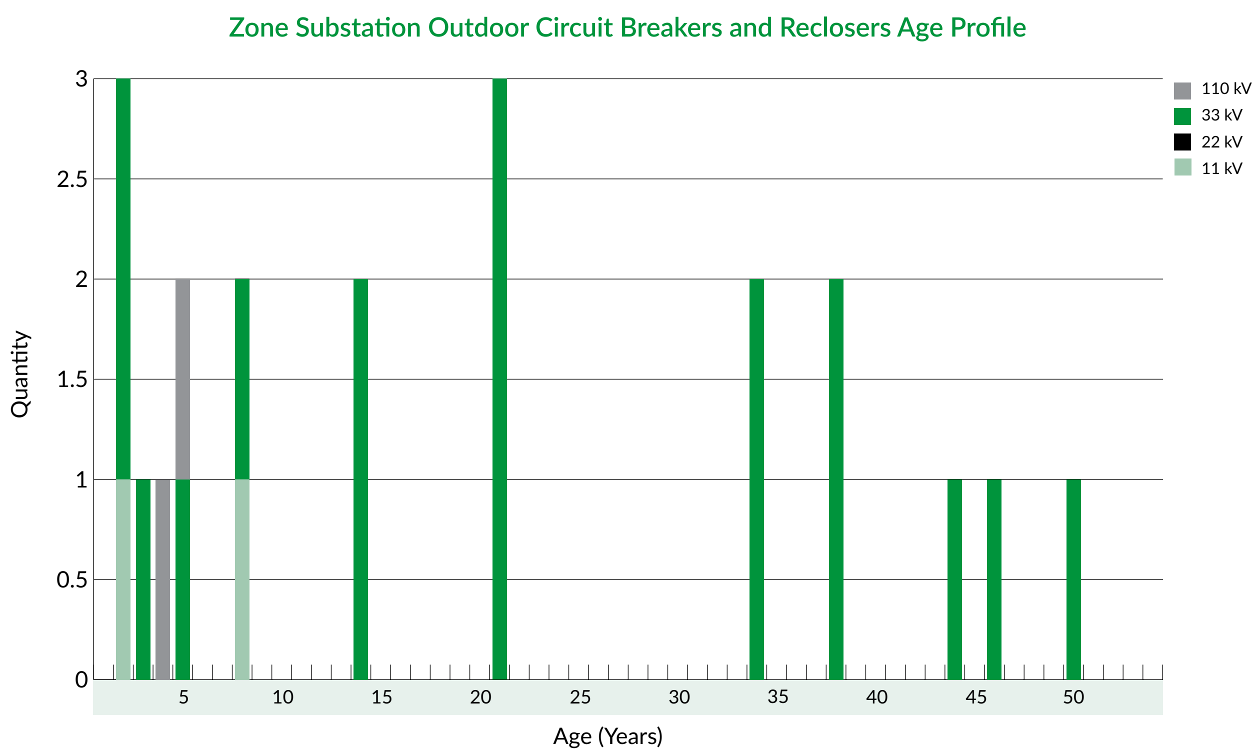


Figure 6.19 Zone Substation outdoor circuit breakers and reclosers age profile

Outdoor switchgear requires more routine and corrective maintenance than indoor switchgear because its components are exposed to outdoor environmental conditions.

6.5.5.6 RENEW OR DISPOSE

Our approach is to replace outdoor circuit breakers and other outdoor switchgear equipment on a condition basis. Outdoor switchgear failure consequences can be large and failure modes can be explosive, particularly with oil-filled switchgear.

Our in-service oil circuit breakers (OCBs) are generally in good condition with no partial discharge issues detected to date, but they do require annual maintenance for the oil and contacts. There is no urgency to replace them as their condition and the maintenance costs alone do not justify replacement.

Table 6.23 Outdoor switchgear renewal approach.

Outdoor switchgear renewal approach	
Renewal trigger	Proactive condition based
Forecasting approach	Age
Cost estimation	Desktop project estimates

RENEWALS FORECASTING

Within the planning period, OCBs are more likely to be replaced as a result of other associated assets needing replacing or due to load growth triggering a replacement of the transformer, replacement of the whole substation, or an upgrade to the protection schemes requiring more modern circuit breakers.

Of the remaining outdoor circuit breakers, only the older pole mounted 33 kV reclosers are likely to need replacement within this planning period.

Our longer term outdoor switchgear renewals quantity forecast use age as a proxy for condition. Older switchgear is more likely to be in poor condition because of exposure to corrosive environments for longer periods. Their mechanical components are also likely to have more wear and tear.

6.5.6 ZONE SUBSTATION PROTECTION RELAYS

6.5.6.1 FLEET OVERVIEW

Protection relays are installed in zone substations in order to detect and interrupt electrical faults while minimising the number of consumers that are affected.

Our network has a mixture of electromechanical, static and numerical protection relays. The majority of zone substations have numerical protection relays installed, these are the industry standard and allow for implementation of the latest control and protection schemes. Numerical relays are able to be connected to our SCADA network, thereby providing timely notice of system disturbances. The communication function is also utilised in combination with the relay's self-checking algorithms to provide notice if the relay detects any internal failures.

6.5.6.2 POPULATION AND AGE STATISTICS

Protection relay age is one indicator of its reliability. Electromechanical, static and numerical relays are all affected differently with age. Literature suggests that the life expectancy of electromechanical relays is around 30 to 40 years. Experience has shown that some electromechanical relays are able to function reliably for over 50 years. After this time the unit is typically not worth repairing and replacement with a modern numeric relay is recommended where this is appropriate.

Electronic relays are able to integrate the functionality of several electromechanical relays into one compact unit. Complex protection and control functions that were not previously available are configurable and most numeric protection relays on our network are connected for remote control and interrogation. Electronic relays have a dominant failure mode associated with degradation of capacitors in their power supply circuitry. Numerical relays installed in the network are expected to have an operating life of approximately 25 years, at the end of this period, the relays are replaced.

Table 6.24 Zone substation protection relay population

Relay Type	Number	% of total
Electromechanical	10	3
Static	14	4
Numerical	313	93

Our protection relay fleet is relatively modern with 94% of all relays installed in the last 15 years. Use of modern relays allows for implementation of advanced functions that provide superior protection of equipment and reduced outages for consumers. Figure 6.20 shows a summary of our protection relay population based on age and quantity.

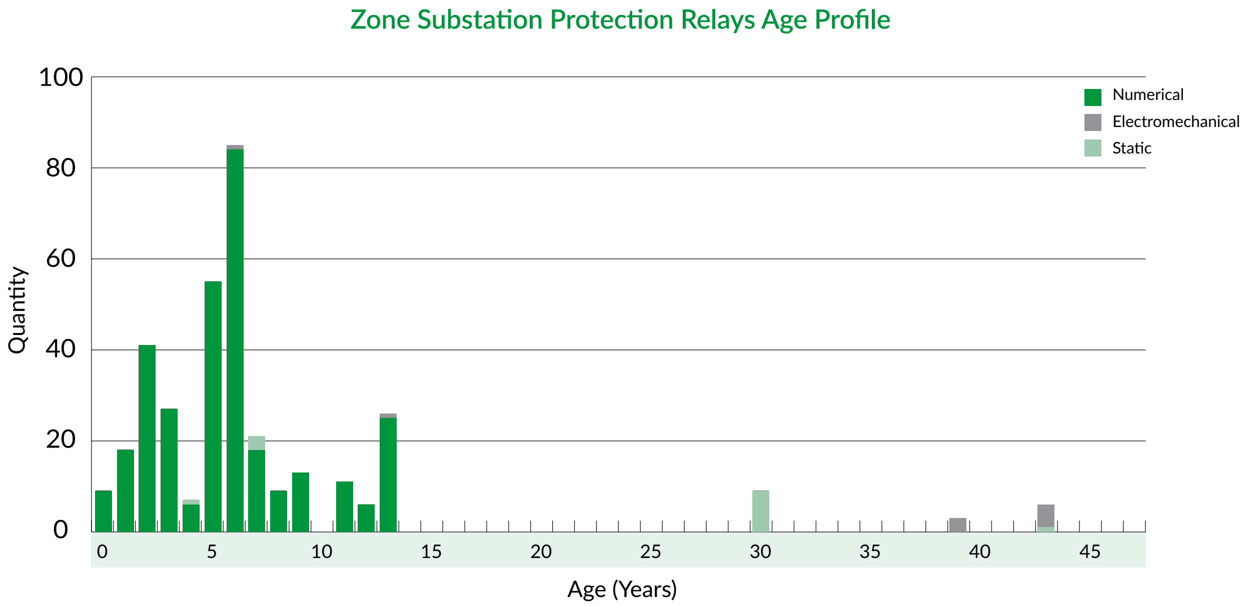


Figure 6.20 Zone Substation Protection Relays – Age profile

6.5.6.3 CONDITION, PERFORMANCE AND RISKS

Condition assessment of protection relays is managed through routine testing and where available, continuous online self-monitoring. All relays currently installed in our zone substations meet the minimum requirements for operating time.

Ageing electromechanical and static electronic relays are posing the greatest risk to the network with regard to protection system reliability. According to statistical information available in the industry, electromechanical relays' reliability reduces significantly after 30 years of service. In order to manage the risk to the network, there are projects underway to replace ageing protection relays in anticipation of their decline in performance.

Most zone substations provide climatic controls to limit temperature/humidity extremes that the relays are exposed to. This assists in extending the life of all components and the relay itself.

Installation of modern numerical relays allows for implementation of higher complexity protection schemes that can provide faster operation for equipment faults and reduced probability of nuisance trips. In many cases a safety improvement is also possible, an example of this are the arc-flash detection capable relays that are installed in zone substation switchboards.

6.5.6.4 RENEW OR DISPOSE

We are continually assessing protection relay requirements, industry best practice and available network data to evaluate possible future investments in our zone substation protection relays.

At our Tekapo substation we are replacing nine static protection relays that are all over 30 years old with modern numeric devices. This project will be completed in the first quarter of 2018. In 2018, three 39 year old electromechanical protection relays will be replaced through the establishment of a new zone substation (replacing an existing site) at Balmoral. The remaining relays that are over 30 years old will be replaced within the first half of the planning period. All replaced relays shall be disposed of unless they serve a purpose as a spare.

The vast majority (94%) of protection devices installed in our network are expected to function reliably with only routine maintenance required over the coming ten years.

6.5.7 BUILDINGS FLEET MANAGEMENT

6.5.7.1 FLEET OVERVIEW

Zone substation buildings mainly house protection, SCADA, communications and indoor switchgear equipment and in some cases load control injection plants. Zone substation sites need to be secure. Buildings and equipment must be well secured for earthquake exposure and designed to minimise the risk of fire, vermin or malicious actions.

We undertook a survey of our existing zone substation buildings following the Christchurch earthquakes to check their condition. This inspection indicated that our buildings were not damaged with only a few with very minor cracks.

6.5.7.2 POPULATION AND AGE STATISTICS

We have 28 buildings located within our zone substations. These are constructed of various materials including mainly steel reinforced concrete, steel "insulated" sandwich panel and some timber frame.

Table 6.25 summarises our population of zone substation buildings by age groups.

Table 6.25 Zone substation building population

Age	Total Quantity	% of total
≤10 years	10	36
11 to ≤20	4	14
21 to ≤30	2	7
31 to ≤40	4	14
41 to ≤50	3	11
51 to ≤60	2	7
61 to ≤70	3	11
Total	28	

Table 6.26 Age range, number and condition of zone substation buildings

Age	Total Quantity	Excellent	Good	Fair	Poor
≤10 years	10	10			
11 to ≤20	4	4			
21 to ≤30	2				
31 to ≤40	4	4	2	1	
41 to ≤50	3		2		
51 to ≤60	2		4		
61 to ≤70	3		2		
Total	28	17	10	1	0

Figure 6.21 outlines the age profile of the zone substation building fleet.

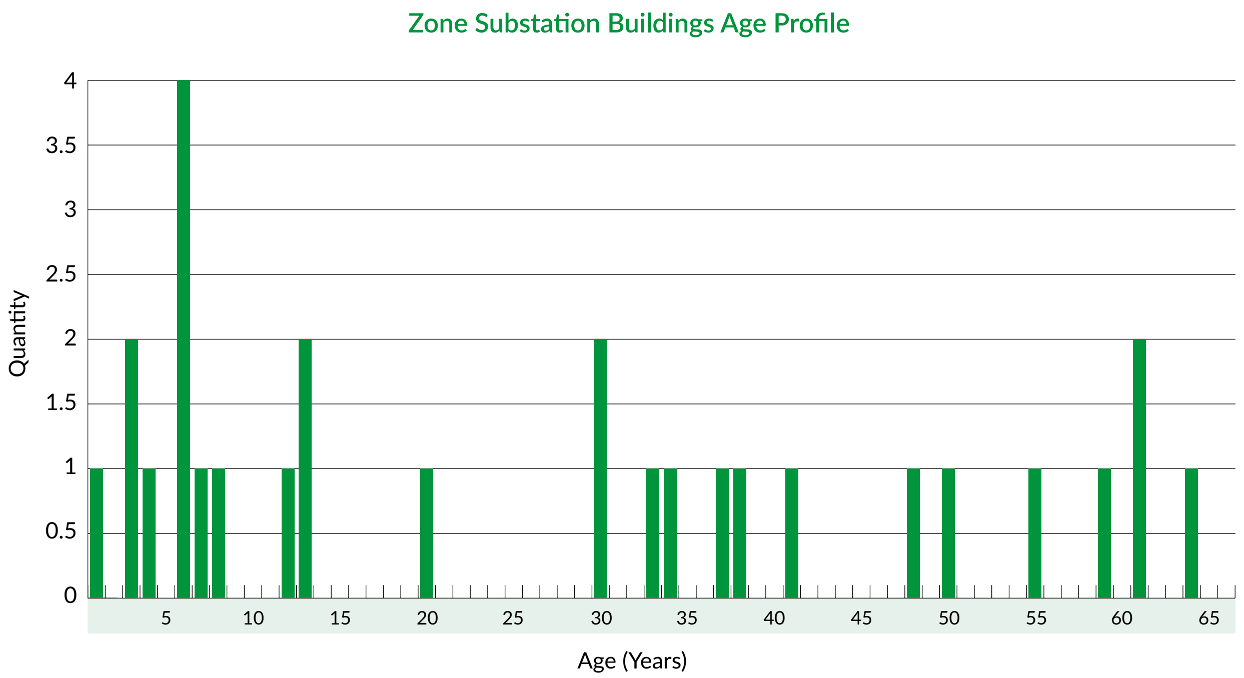


Figure 6.21 Zone substation buildings age profile

6.5.7.3 CONDITION, PERFORMANCE AND RISKS

The condition of our zone substation buildings is generally good to excellent with a number of legacy buildings and a significant number of new and refurbished buildings resulting from recent growth driven zone substation projects.

We have reviewed the condition of all our zone substation buildings and have been maintaining, refurbishing, and replacing these assets as required.

Four of our ripple plant buildings are of older timber frame construction and are generally sound but some require maintenance. Of these, one was completely refurbished for re-use in 2017 for a new replacement ripple plant; another has corrugated fibrous cement roofing containing asbestos; and the last has recently had its galvanised steel roof replaced. All four are legacy buildings whose exterior walls are partially clad with "polite" fibrous (asbestos) cement panels and partially with exterior ply (for seismic strengthening), and painted. As long as the asbestos panels are not disturbed and are maintained in a painted state, the asbestos will not be a hazard. Therefore these buildings do not need to be refurbished or replaced because of the asbestos. Should any future work be required that might disturb the asbestos, we will arrange for the removal of the asbestos from that building by a suitably qualified contractor.

6.5.7.4 DESIGN AND CONSTRUCT

We design our zone substation buildings to be functional and to comply with the required seismic strength. The layout of our newer buildings have been standardised in terms of functionality. The size varies to suit the various substations. We also consider the visual aesthetics of the building where applicable.

All our newer buildings have a brick with steel roof construction except for small buildings which are made with steel sandwich panels (i.e. portable style buildings).

6.5.7.5 OPERATE AND MAINTAIN

We routinely inspect our zone substation buildings to ensure they remain fit for purpose and any remedial maintenance work is scheduled as required. General visual inspections and housekeeping are performed monthly with more detailed inspections undertaken annually. Ensuring our buildings are secure is essential to prevent unauthorised access.

Table 6.27 Zone substation building maintenance and inspection tasks

Maintenance and inspection task	Frequency
General visual inspections and housekeeping	Monthly
More detailed inspections	1 yearly

6.5.7.6 RENEW OR DISPOSE

As discussed above we will be undertaking specific maintenance to ensure our buildings are safe and able to assist the equipment they house to maintain a reliable supply. There are two of our older ripple plant buildings that will be replaced or refurbished during the planning period.

There are two of our smaller legacy switch room buildings that will be replaced with new buildings during the planning period.

6.5.8 LOAD CONTROL INJECTION PLANT FLEET MANAGEMENT

6.5.8.1 FLEET OVERVIEW

Load control systems are used to manage the load profiles of customers with controllable loads (e.g. hot water or space heating) and also to shed load such as irrigation when required during network emergencies.

Load control systems are highly effective at reducing demand at peak times by deferring non time-critical power usage. Benefits of load control include more predictable peak demand and allowing us to defer distribution capacity increases. Wider benefits include a reduced need for peaking generation plants and investment deferral.

Figure 6.22 Load control injection plant – Bells Pond substation

6.5.8.2 POPULATION AND AGE STATISTICS

We currently operate load control injection plants on our network, comprising both modern and aged equipment.

Table 6.28 summarises our load control injection plant population by type.

Table 6.28 Zone substation load control injection plant population

Type	Plant	% of Total
Modern electronic plant	4	80%
Legacy rotary plant	1	20%
Total	5	

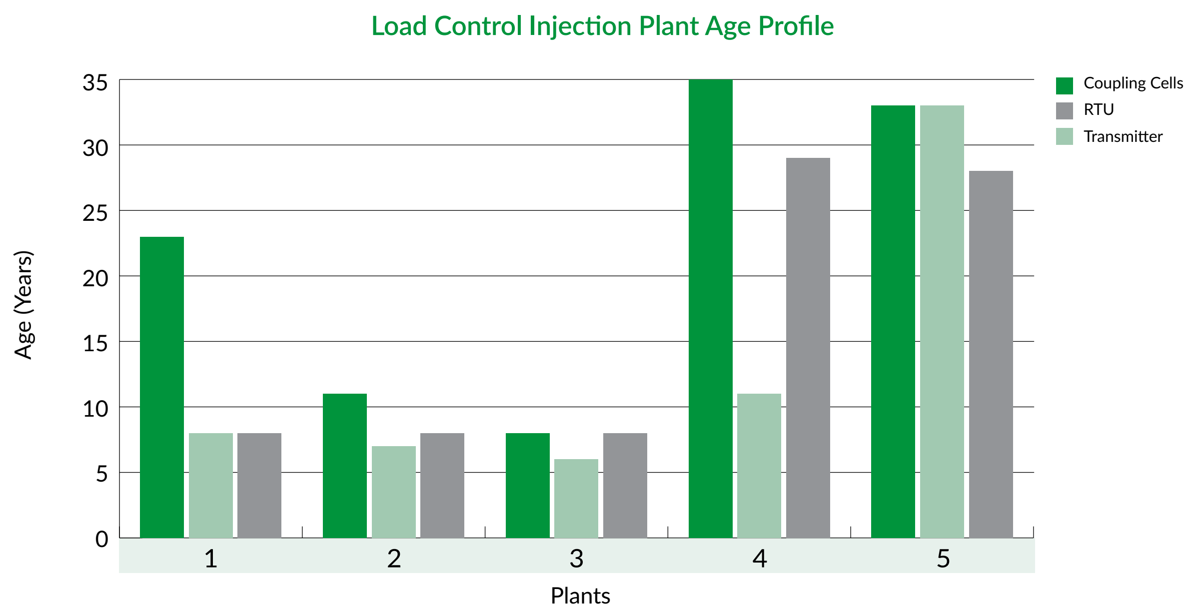


Figure 6.23 Zone substation load control injection plant age profile

6.5.8.3 CONDITION, PERFORMANCE AND RISKS

A new modern plant was commissioned at our Albury zone substation during 2017 after the building was refurbished.

The Tekapo legacy rotary load control plant is considered obsolete. However, it is still performing well. It controls a relatively small number of ICPs in its area with limited load that can be shed. It is proposed that when it finally needs to be decommissioned the load control will be undertaken by time clocks in new advanced meters and associated programmable relays.

Three of our ripple plants have relatively new remote terminal units (RTU) which are performing well. The other two ripple plants have old Conitel RTUs which are close to 30 years old. They have performed well to date and are due for replacement. In addition, they are proving a challenge for connection to our SCADA. The Conitel RTU at the Timaru zone substation was replaced in 2017. The second Conitel RTU on the legacy plant at the Tekapo substation may not be replaced since the plant will be allowed to reach end of life and then be decommissioned.

6.5.8.4 DESIGN AND CONSTRUCT

Our standard for current and future plant is the DECABIT channel command format. The DECABIT standard has proven to be the most reliable and error free standard and is widely used in New Zealand.

6.5.8.5 OPERATE AND MAINTAIN

Due to the specialist nature of load control plant, we are considering a backup and service support contract that covers our modern static installations. This would cover annual inspections, holding of critical spares and after-hours emergency support.

Table 6.29 Load control injection plant maintenance and inspection tasks

Maintenance and inspection task	Frequency
General visual inspection of plant. Operational tests.	1 yearly
Diagnostic tests, such as resonant frequency checks, signal injection levels and insulation resistance.	5 yearly

6.5.8.6 RENEW OR DISPOSE

The legacy installation referred to above uses a higher ripple frequency of 500 Hz whereas our modern plants use 317Hz. Obtaining spares and manufacturer support is very difficult so when it eventually fails it will be decommissioned in favour of the smart meters time clocks, as mentioned above.

The ripple plant at our Bells Pond zone substation had the coupling cell upgraded in 2017 to accommodate the second transformer that is currently being installed. The transmitter is adequately rated and will not be upgraded.

Our ripple plant at Timaru substation will be replaced in the 2018/19 financial year. This plant is reaching the end of its design life and is not ideally rated for the Transpower supply transformers that were replaced in 2016. In addition the load on this plant has also increased over the years and is now at the rating of the plant during peak load conditions.

6.5.9 OTHER ZONE SUBSTATION ASSETS FLEET MANAGEMENT

6.5.9.1 FLEET OVERVIEW

Other zone substation assets fleet comprises outdoor bus systems, fences and grounds, earthing, communications masts, lightning protection systems, security/access control systems and fire systems.

Outdoor bus systems are switchyard structures comprising pole structures, HV busbars and conductors, associated primary clamps/accessories, support posts and insulators.

The risk of a lightning strike to zone substation HV equipment in South Canterbury is very low. Nevertheless, most of our sites are designed with lightning protection systems to reduce the impact of a lightning strike on HV equipment. Lightning protection comprises earthed rods mounted on masts/poles and surge arrestors on equipment.

6.5.9.2 CONDITION, PERFORMANCE AND RISKS

One of the safety risks in our zone substations are step and touch potential hazards during earth faults. A layer of crushed rock is installed in the outdoor switchyards of all our zone substations to reduce step and touch potential hazards by providing an insulating layer.

Over the last few years we used a consultant to carry out current injection testing of most of our zone substations to evaluate the step and touch voltage hazards. As part of the test, the crushed rock layer is also inspected. Areas that are found to be non-compliant against industry guidelines are fixed and crushed rock is reinstated where required. Most of our sites have compliant earthing systems and the crushed rock is in a good condition. Balmoral substation has been identified as requiring an earthing upgrade but this site is scheduled for a complete rebuilt because of load growth. The earthing system will be brought up to standard as part of the rebuild. Another site is being extended for the provision of connection points for the mobile substation and will require additional earthing.

Another key risk we manage is access and site security. Fencing around zone substations is very important to keep the site secure and prevent unwanted access. The condition of our fencing is very good and security systems are generally good to excellent. We have a programme to replace old security and fire protection systems that are no longer maintainable so that we can bring all sites up to excellent status over the planning period.

6.5.9.3 DESIGN AND CONSTRUCT

We follow standard designs for HV overhead bus systems and fencing.

For the earthing designs, we use an external specialist consultant. After installation of the earthing system, we get the external specialist consultant to test the effectiveness of the earthing system. They carry out current injection testing to confirm that step and touch voltages are within the desired limits and that the earthing system is as per design. Additional work may be carried out if the testing indicates that this is required.

6.5.9.4 OPERATE AND MAINTAIN

Our general zone substation maintenance tasks are summarised in Table 6.30. The detailed regime is set out in our maintenance standards.

Table 6.30 Other assets maintenance and inspection tasks

Maintenance and Inspection Task	Frequency
Site vegetation work – mowing, weeding. Check waterways.	1 monthly
General visual inspection of outdoor structures, busbars, site infrastructure, security equipment and fencing.	1 monthly
Detailed visual inspection of site infrastructure. Thermal scan of busbar connections.	1 yearly
Detailed inspection of busbar connections, insulators, and bushings. Detailed condition assessment of outdoor structures.	4 yearly
Review of step and touch voltage hazards and carrying out current injection testing. Crushed rock inspection.	10 yearly

6.5.9.5 RENEW OR DISPOSE

Faulty components are replaced/repaired as required.

Balmoral substation is old and most of the old equipment from that site will be disposed of during the rebuild.

6.6 DISTRIBUTION TRANSFORMERS

6.6.1 OVERVIEW

This chapter describes our distribution transformers portfolio. The portfolio includes three fleets:

- Pole mounted distribution transformers
- Ground mounted distribution transformers
- ‘Other’ distribution transformers, which includes voltage regulators, capacitors, conversion and SWER transformers

This chapter provides an overview of these assets, including their population, age and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

PORTFOLIO SUMMARY

Investment in distribution transformers for the planning period is forecast at $ 10.57 M. This portfolio accounts for 14% of the renewals expenditure over the planning period.

6.6.2 PORTFOLIO OBJECTIVES

Distribution transformers convert electrical energy of higher voltage to a lower voltage used by consumer appliances. Their effective performance is essential for maintaining a safe and reliable network.

Transformers come in a variety of sizes, single or three phase, and ground or pole mounted. All of our transformers are oil filled, which carries environmental and fire risks. Managing our distribution transformers assets, including correctly disposing of these assets when they are retired, is critical to safeguarding the public and mitigating oil spills.

To guide our asset management activities, we have defined a set of objectives for our distribution transformers.

Table 6.31 Distribution transformer portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	Seismic evaluation of all two pole substations and relocation at ground level where appropriate. Action all oil leaks as soon as possible and treat any contaminated soil.
Service levels	Replace pole mounted transformers within 24 hours of failure. Continue to monitor ground mounted transformers through maintenance inspections and condition assessments for timely replacement.
Cost	Ensure all installations are fit for purpose and most cost effective solutions are designed and constructed.
Community	Consider location of any new distribution substations and impact on residents or businesses. Consult with community on placement of new transformers.
Asset management capability	Implement inspection and maintenance programs in our EAM system. Record condition information is EAM system.

6.6.3 FLEET OVERVIEW

Distribution transformers step down voltage for local distribution. Pole mounted transformers are generally smaller and supply fewer customers than ground mounted transformers. These are usually located in rural or suburban areas where the distribution network is overhead. In the suburban areas where the supply is overhead, the larger pole mounted transformers are referred to as two pole substations as depicted in Figure 6.24.

The majority of our ground mounted distribution transformers are located in suburban and CBD areas that are supplied via underground cable networks. These units are larger, more expensive and supply more consumer connection points as well as more critical loads. An example of this is the more than 60 units (500 kVA to 1500 kVA) on the Fonterra dairy factory site. A typical unit is shown in Figure 6.25.

Figure 6.24 Pole mounted distribution transformers

Voltage regulators are distribution transformer 'type' used to improve the voltage levels on long distribution lines, and as such they do not provide a power supply to consumers. The majority of our voltage regulators are pole mounted and an example in shown in Figure 6.25.

Figure 6.25 Ground mounted transformer (left) and voltage regulator (right)

6.6.4 POPULATION AND AGE STATISTICS

We have 5,661 oil filled distribution transformers in service and the age profile resembles that of the 11 kV overhead lines and cables. The most significant investments in distribution substations and transformers were made in the late 1950's, early 1970's, 2000's, and 2010's. The in-service quantities of distribution transformers by kVA rating and distribution substation type are given in Table 6.32 and Figure 6.26 respectively.

Table 6.32 Distribution transformer population by rating

Rating	Number	% of total
≤ 15 kVA	2,695	45
>15 and ≤ 30 kVA	1,112	18
>30 and ≤ 100 kVA	1,080	18
>100 and ≤ 250 kVA	591	10
>250 and ≤ 500 kVA	387	6
>500 and ≤ 1500 kVA	158	3
Total	6,023	

The expected life of pole mounted units typically ranges from 45 to 60 years. While the majority of our distribution transformers are less than 30 years old, some are older than 60 years.

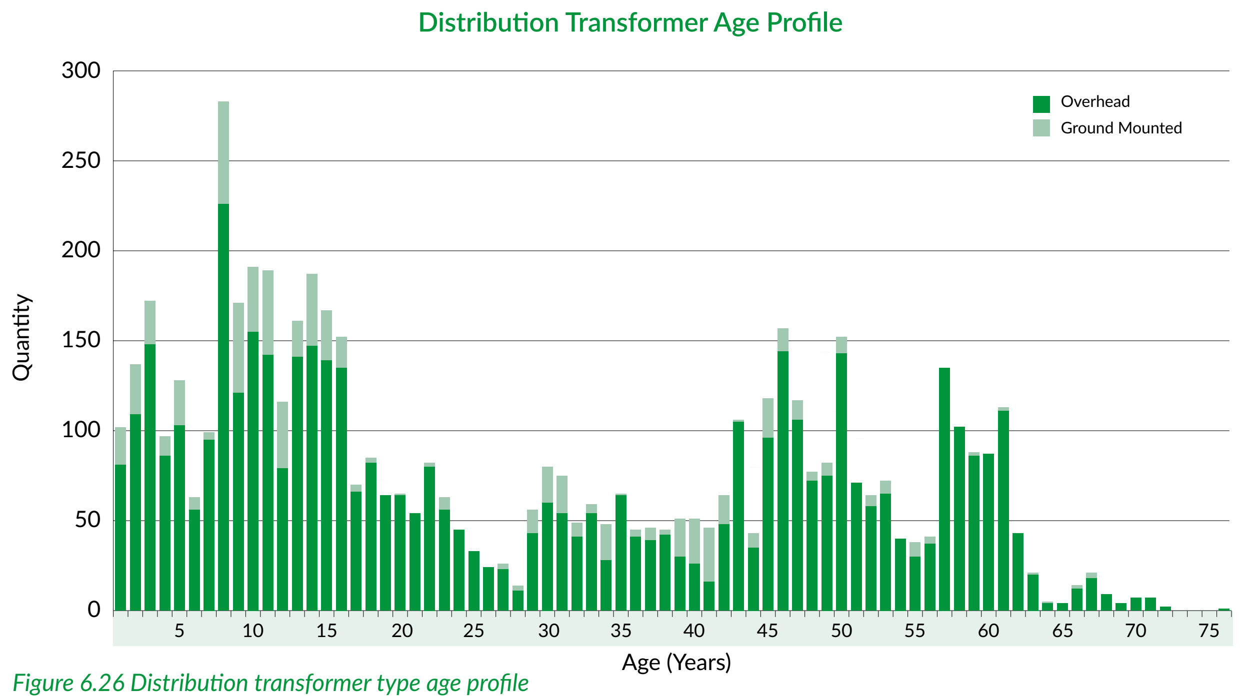


Figure 6.26 Distribution transformer type age profile

We have some 31 voltage regulators installed on our network. The majority is less than ten years old and reflects the increase in rural load on our network as a result of dairy conversions and on farm irrigation that started in the early 2000's.

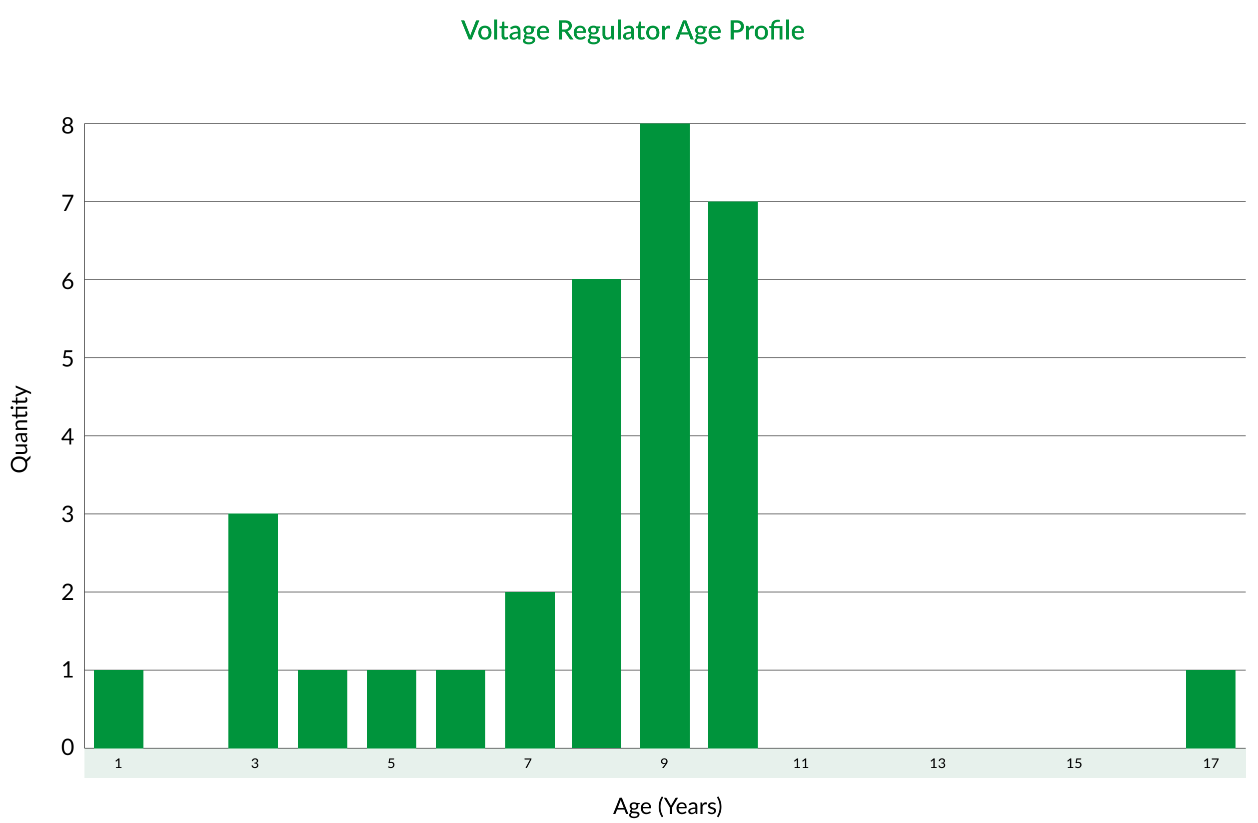


Figure 6.27 Voltage regulator age profile

6.6.5 CONDITION, PERFORMANCE AND RISKS

The biggest risk to our fleet is lightning and vehicles coming into contact with our poles. Overall our distribution transformer fleet are in a good condition. Because of the standards to which they are designed and manufactured, they are capable of operating beyond their nameplate ratings.

6.6.6 DESIGN AND CONSTRUCT

Distribution transformers are designed and constructed to international standards. They are robust pieces of equipment that seldom fails. When sizing transformers for a specific application we do allow for some measure of future growth. This eliminates the need to upgrade transformers on a regular basis as a result of generic load growth. The incremental premium payable for the increased capacity is well below any upgrade or replacement costs.

6.6.7 OPERATE AND MAINTAIN

Condition assessment for pole mounted units is done as part of our overhead line inspections regime. For ground mounted units which tend to be larger and supplying substantially more consumers, we have scheduled inspection and maintenance program.

Distribution transformers do not require intrusive maintenance. Pole mounted units are often run to failure as these are easily replaced at a much lower cost than to implement a maintenance regime. Large ground mounted units are more thoroughly checked for oil leaks, rust and bushing damage as part of the maintenance program.

Our voltage regulators are maintained on a four yearly program due to the fact that they have electronic controllers that require regular testing. In addition there are internal contacts that can wear depending on the number of operations, and they are also inspected and repaired.

6.6.8 RENEW OR DISPOSE

Pole mounted transformers which makes up around 60% of our fleet are replaced on a reactive basis. This can be due to failures related to lightning, third party damage or as a result of condition assessment during overhead line inspections.

The larger ground mounted and two pole substation units are proactively replaced based on age and condition. All scrapped transformers' oil is drained and re-cycled through certified processors.

6.7 DISTRIBUTION SWITCHGEAR

6.7.1 OVERVIEW

This chapter describes our distribution switchgear portfolio and summarises our associated fleet management plan. The chapter provides an overview of these assets including their population, age and condition. The portfolio includes the following fleets:

- **Ground mounted switchgear** which consist mainly of ring main units (RMU), also includes switches, fuse switches, and links. This type of switchgear is mainly associated with our underground cable networks. Our RMU fleet consists of oil and SF_6 insulated units.
- **Pole mounted switches** includes drop out fuses, disconnectors (air break switches or ABS) and links. The vast majority is found on our 11 kV overhead network. LV switches are not included in the data.
- **Circuit breakers, reclosers and sectionalisers.**

Examples of these devices are shown in Figure 6.28 with the red arrows pointing to a fuse link on the left and an ABS on the right.

Figure 6.28 Examples of a fuse link and an ABS on the left and a recloser on the right respectively

6.7.2 PORTFOLIO OBJECTIVES

The portfolio objectives for our distribution switchgear fleet is summarised in Table 6.33.

Table 6.33 Distribution switchgear portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	No injuries due to failure or operation of switchgear No significant SF_6 leaks
Service levels	Continue program to automate reclosers and voltage regulators. Investigate the use of low cost automated devices as tie switches.
Cost	Cost effective expenditure on this asset fleet. Ensure fit for purpose designs based on risk reduction.
Community	Minimise interruptions due to planned and unplanned outages. Inform all affected consumers of planned outages in a timely manner.
Asset management capability	Develop maintenance programs in AMS. Capture condition data in AMS to inform maintenance and investment expenditure.

6.7.3 POPULATION AND AGE STATISTICS

6.7.3.1 RING MAIN UNITS

Figure 6.29 shows our population and age profile for the oil RMU types on our network. Around twenty three percent (all oil) are at or just beyond the ODV life of 40 years.

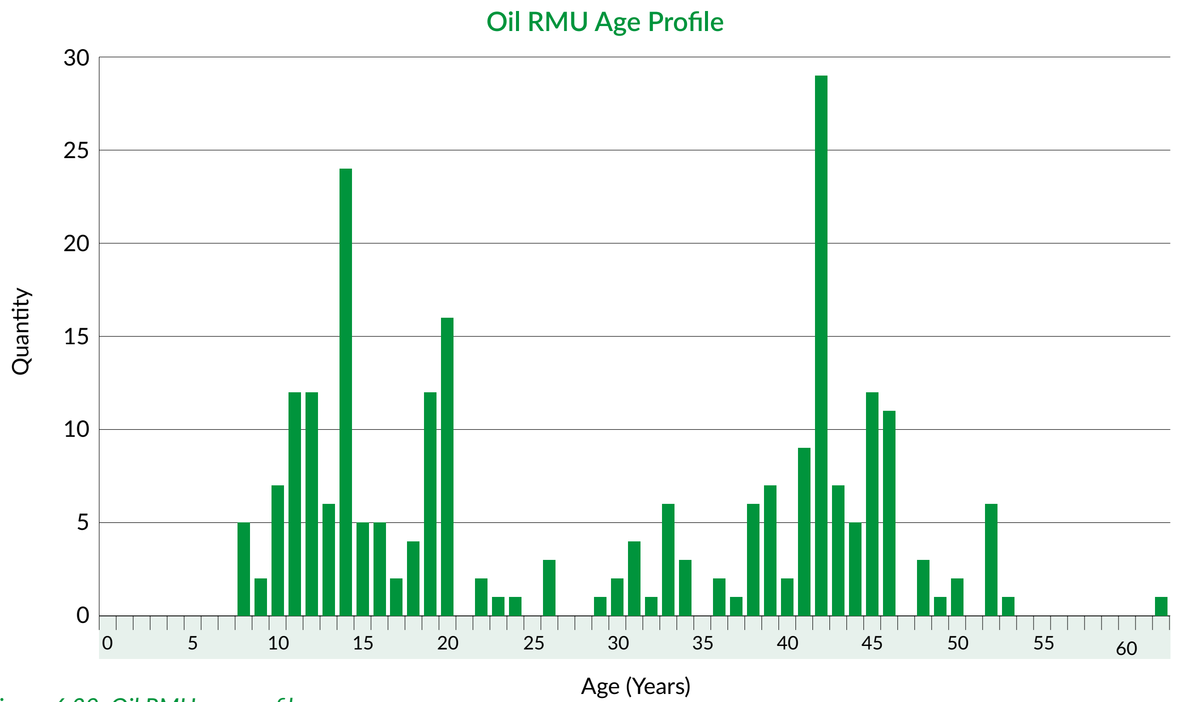


Figure 6.29 Oil RMU age profile

As shown in Figure 6.30 our SF_6 insulated RMUs are relatively new with the oldest just on ten years of age.

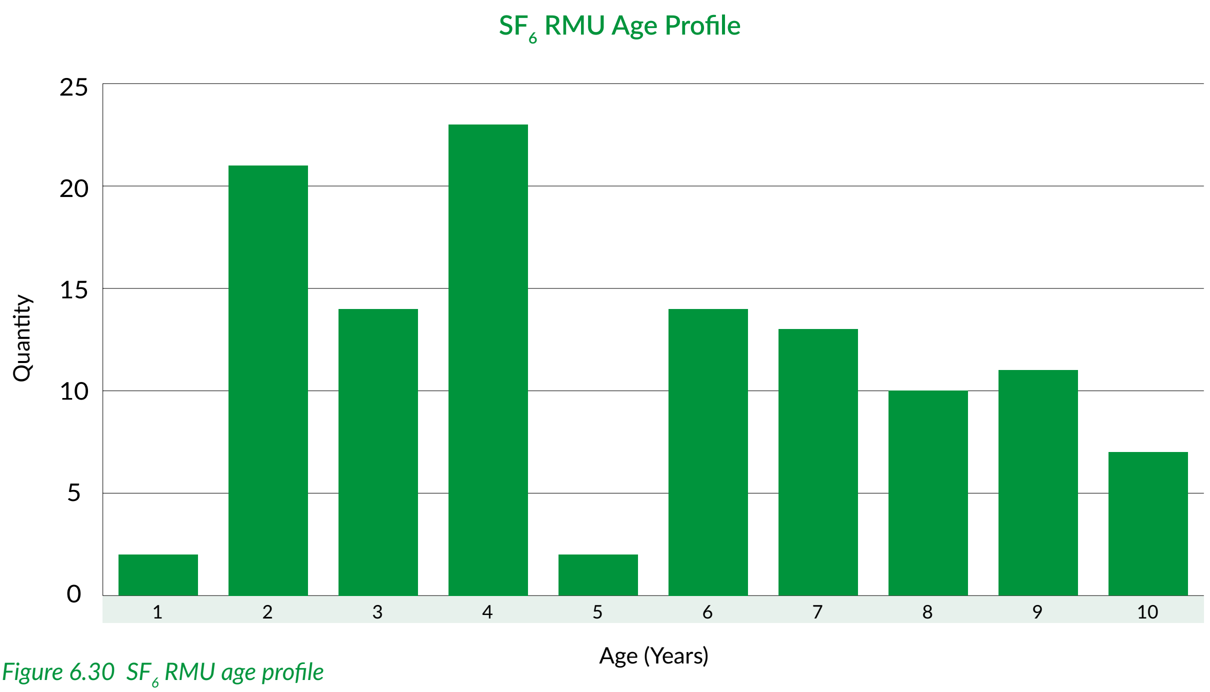


Figure 6.30 SF_6 RMU age profile

6.7.3.2 POLE MOUNTED FUSES AND SWITCHES

We have approximately 7,074 pole mounted switches with ages as shown in Figure 6.31.

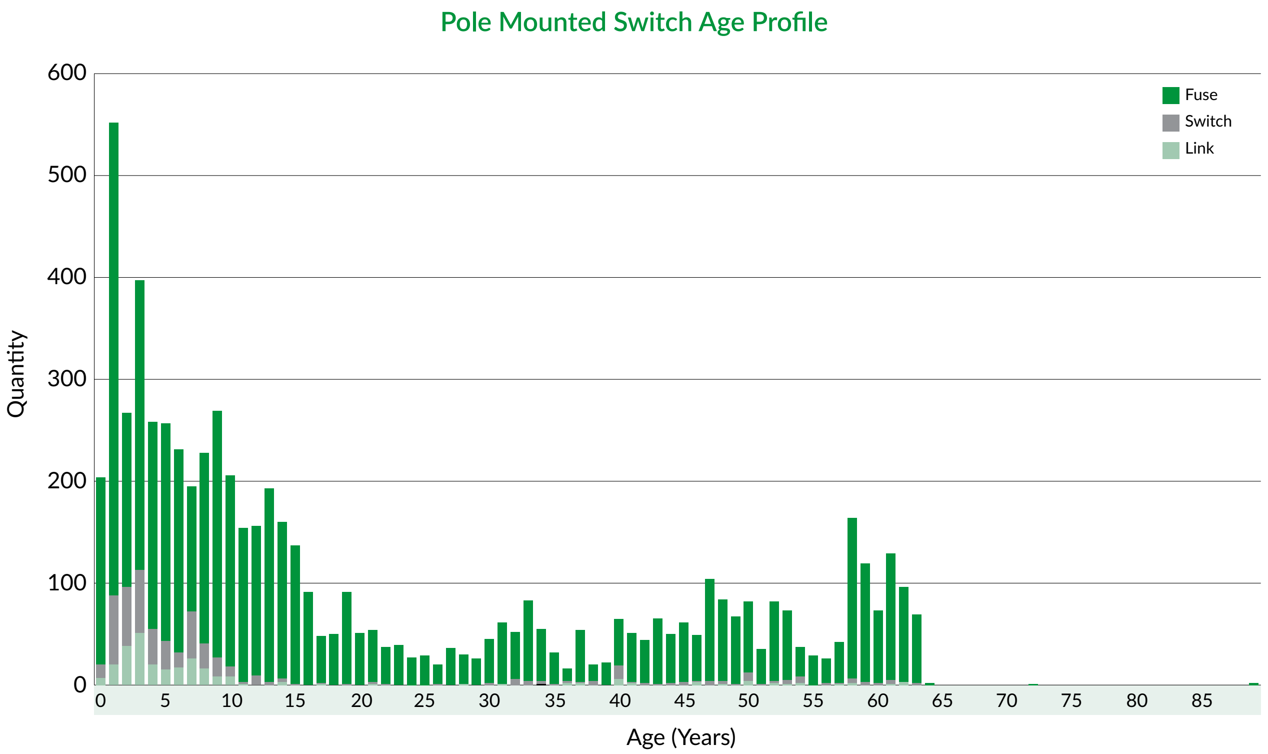


Figure 6.31 Pole mounted switch age profile

A significant proportion of pole mounted switches is less than 15 years old, while some date from nearly 60 years ago. They are fairly simple pieces of equipment and maintenance normally revolves around the lubrication of moving parts.

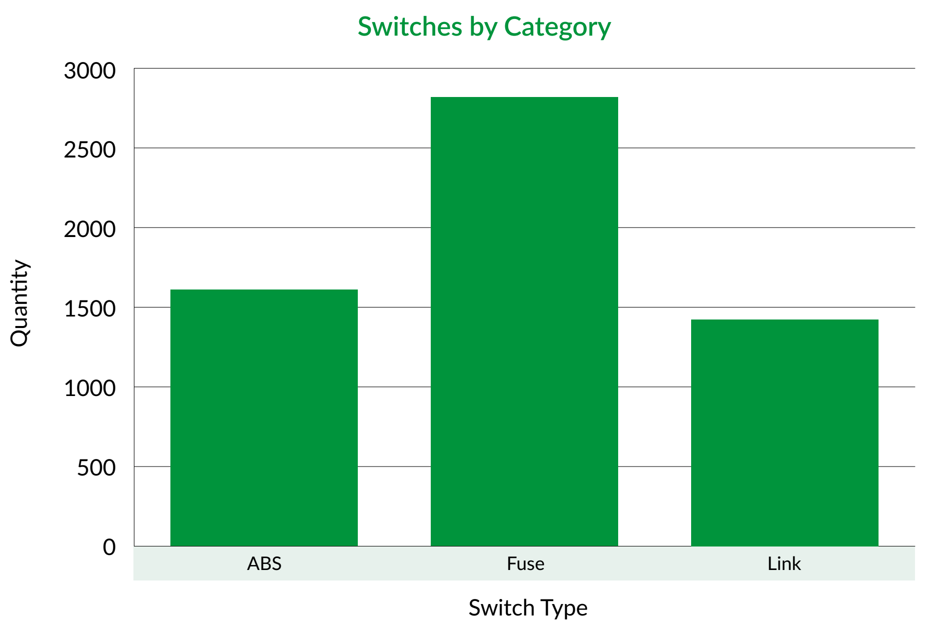


Figure 6.32 Pole mounted switches by category

6.7.3.3 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS

We have several makes and models of 11 kV pole mounted reclosers in service on our 11 kV distribution network. The types and quantities are summarised in Table 6.34. Reclosers and sectionalisers are used to protect and isolate the healthy network from faulty parts. By appropriately locating them, outages are managed and overall network reliability improved.

Table 6.34 Recloser types and quantities

Type	Quantity
Vacuum interrupter & oil insulation	9
Vacuum interrupter & SF_6 insulation	2
Vacuum interrupter & epoxy resin insulation	19
Vacuum interrupter & solid polymer insulation	14

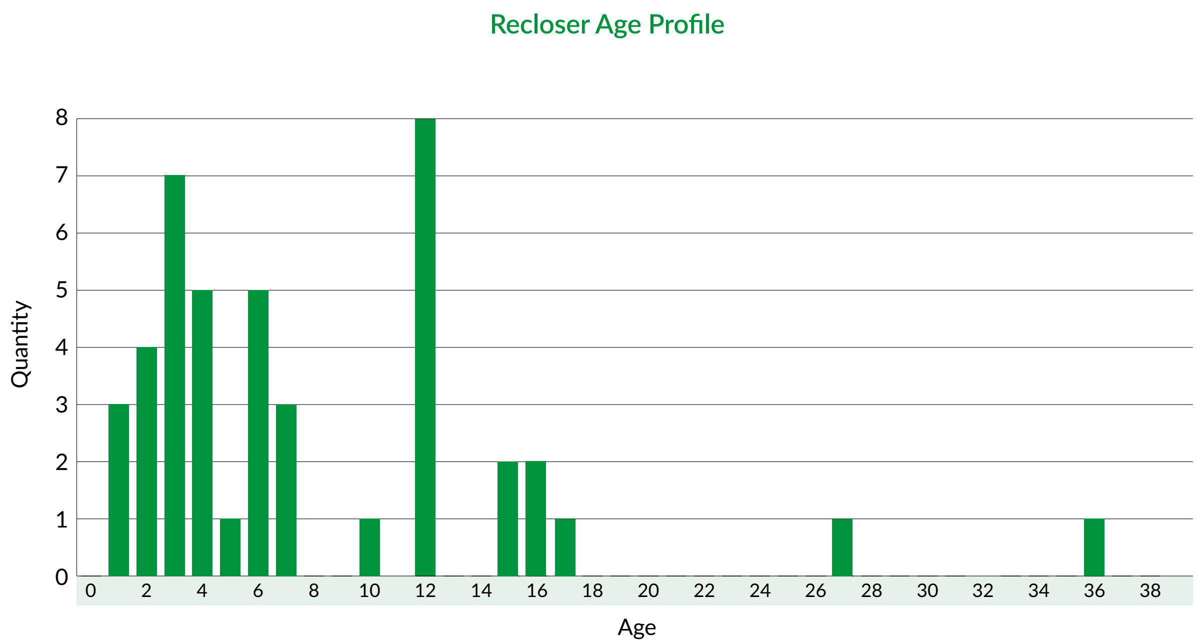


Figure 6.33 Recloser age profile

6.7.4 CONDITION, PERFORMANCE AND RISKS

6.7.4.1 GROUND MOUNTED SWITCHES

Even though just less than a quarter of our oil RMUs is close to their ODV life, their condition is fair to good. These older units were designed to international standards that were more robust with respect to tolerances than modern equivalents. Their condition, like most mechanical devices is reflected in how well they were maintained, and how hard they were operated. It is fair to say our RMUs have not worked very hard over the years and this is reflected in their condition.

Our RMUs are performing well for the purpose they were designed. With the increased focus on reliability of supply, the only lack in performance is one of automation. Modern gear are also designed and built with more focus on maintainability and also specifically less maintenance over the life of the asset. We have now installed a small number of modern RMUs with automation and will continue this practice as part of our renewal and replacement programs.

The biggest risk related to this type of switchgear is one of fire with oil filled equipment. Depending on the type of failure, there is an increased risk that it could result in a fire. Both old and modern gear, due to the nature of their application and function, poses a risk of arc flash. Modern equipment designers are accounting for this and we specify arc rated and arc vented equipment where possible.

There is also an inherent environmental risk associated with equipment that contains SF_6 gas for insulation. We mitigate this risk through ourSF_6 register and the use of specialised and approved contractors.

6.7.4.2 POLE MOUNTED FUSES AND SWITCHES

Overall our pole mounted switches are in a good condition. The majority of our older assets are transformer fuses.

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

6.7.4.3 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS

The oldest 11 kV recloser model in service, dating between

1980 and 2003, has vacuum circuit breakers with mechanism and connections insulated in oil. The original controllers of these units were replaced between 2010 and 2015 and are in good condition. We estimate that these units have at least another 13 years of life before they may need to be replaced. They will be monitored for condition during their annual battery and earth tests, and their 5 yearly full maintenance cycle.

The next oldest 11 kV reclosers are two SF_6 units installed in 2005. These units should have another 20 years of life and will be monitored for condition during annual and five yearly maintenance cycles.

The third oldest units were installed between 2005 and 2013. There are 19 of these units in service. These have vacuum circuit breakers with solid insulation. The first batch suffered from lack of immunity from noise on the 11 kV network due to insufficient filtering on their current sensor circuits. This was eventually corrected by the manufacturer. Another drawback suffered by this make of recloser was that the current sensors and associated protection circuitry appeared to be unable to distinguish low primary load current (<10 A) imbalance from earth faults. Consequently some of these units had to be reassigned to locations with a higher minimum load current. Another problem arose necessitating a modification to the power supply earthing, and all the units were updated. These units are in good condition. We expect that these reclosers' controllers should not need replacing before 2025, and the CB themselves not before 2030.

The most recent 11 kV recloser model in service was introduced in 2013 and is presently our preferred model. There are presently 14 of these units in service. The condition of these reclosers is generally considered excellent. We expect that these reclosers' controllers should not need replacing before 2025, and the CB themselves not before 2035. As for the other recloser models they will be monitored for condition during annual and five yearly maintenance cycles.

6.7.5 DESIGN AND CONSTRUCT

We have standardised our designs around two RMU types based on application and ratings. Our designs also require that three core cables be trifurcated in the ground and that single core cables only be terminated inside the RMU. This eliminates the risk of trifurcation failures also damaging the RMU. The higher current rating RMU type is installed with a locked fibre glass protective cover over it. This also prevents public access to the cables that are terminated inside the RMU.

Air break switches, as part of the pole mounted switch family are mostly designed and constructed on the network in such a way that they can be bypassed if maintenance is required. This ensures that maintenance activities can be undertaken without any power outages.

Our design philosophy for 11 kV pole mounted reclosers is that they must be able to be bypassed by an air break switch (ABS) or disconnector to allow supply to be maintained during maintenance of the units and in the event of a failure of a unit when in service. This is usually achieved by the use of a bypass ABS above, and two sets of isolating links on either side of, the recloser. The additional cost of this equipment is considered acceptable compared with the risk of a prolonged consumer outages and SAIDI penalties.

We have also embarked on a programme of automation of the reclosers so that they may be operated remotely via our existing zone substation SCADA system. This is achieved through the use of radio communication with each recloser site.

6.7.6 OPERATE AND MAINTAIN

6.7.6.1 GROUND MOUNTED SWITCHES

Maintenance tasks include an annual visual inspection and a scheduled four to five year fixed maintenance program that aims to maintain every switch. This service also includes an oil test where applicable. We are currently in the process to "catch-up" on our program which is challenging for a number of reasons namely:

- Ability to arrange access to the equipment through outages due to the original network design some twenty to thirty years ago,
- Third party schedules such as units on industrial processing sites where production is affected.

These devices are normally operated by hand, with more modern versions having the capability to be automated. Since a large number of them are located in urban areas, their enclosures are locked and secured at all times. Our lock replacement program that started two years ago to replace all locks on our network with an improved quality lock, also applies to these assets.

6.7.6.2 POLE MOUNTED FUSES AND SWITCHES

This asset class is maintained as part of the overhead line inspection and refurbishment program. They are fairly simple pieces of equipment and maintenance normally revolves around the lubrication of moving parts. It is often the case that these devices are not operated for many years.

To avoid ferro-resonance where transformers are connected with a cable circuit, the cable connection is through a disconnector (three-phase disconnect), surge arresters, and a three-phase ganged drop-out unit. With ganged drop-out units becoming difficult to source, we have introduced the use of transformers with internal HV fuses. Switching will still be carried out via the disconnector.

6.7.6.3 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS

Reclosers and sectionalisers are maintained on a four yearly basis in addition to an annual visual inspection regime. The maintenance requires the equipment to be taken out of service. This is done without the need for an outage because of our standardised installation design.

Reclosers are in addition to a switchable device also a protective device, to isolate faults from the rest of the network. Because they are distributed all over our network we have embarked on a program to automate these devices. This allows us to operate them from our control centre which reduces outage times and improves reliability. To date we have automated 35 (or approximately 73%) of our reclosers.

6.7.7 RENEW OR DISPOSE

Our ground mounted switchgear and specifically our RMUs are replaced mainly based on condition. However, with the increased focus on reliability and health and safety, we have also embarked on a project to renew our underground substations, all of which contains one or more RMUs. We also have a budget to replace older units depending on the outcome of our maintenance and inspection program. We typically replace approximately 2% of our oil RMU fleet annually.

Pole mounted switches are replaced as part of our overhead line inspection and maintenance program. As a result, most units are replaced during these programs if they are deemed not in a condition to last another ten years.

Condition, including operating performance, is the primary criteria for replacement decisions of pole mounted reclosers. Age will also be taken into account particularly as concerns the electronic components such as the controller and automation equipment. After reaching a certain age, usually considered to be 20 years, electronic equipment can fail unexpectedly due to aging of components such as capacitors. Batteries are also replaced based upon age, usually after 5 years from date of manufacture. We will be replacing the two oldest reclosers on our network within the planning period.

6.8 SCADA AND COMMUNICATION SYSTEMS

6.8.1 OVERVIEW

The SCADA system provides monitoring, remote control and the acquisition of data of our network. The SCADA system consists of a master station, RTUs located at substations and controllable devices, and a communications system that connects the master station to the RTUs.

At present the technology is diverse as it was installed over the years with different standards and requirements. We have undertaken considerable work to improve standardisation and this will continue in this planning period.

6.8.1.1 MASTER STATION

A master station is essentially a central computer server that manages the SCADA system. We run our primary master station in our Washdyke office site with a backup on hot standby in our North Street substation.

We are continually developing and adding new modules to our SCADA system to meet the network's needs for the foreseeable future.

6.8.1.2 REMOTE TERMINAL UNITS

RTUs are electronic devices that interface network equipment with the master station. They transmit telemetry data to the master station and relay communications from the master station to control connected devices.

We have a range of different RTUs used across our network using different protocols. We are standardising on DNP3 protocol using selected SEL relays.

6.8.1.3 COMMUNICATIONS

The communications network supports our SCADA system as well as our protection, metering and telemetry systems. The communications network consists of different data systems and physical infrastructure, including fibre optic circuits, radio (UHF and VHF), microwave and ethernet IP based circuits. The scope of the communications network also includes the infrastructure that houses communication systems, including masts, buildings, cabinets and antennae. Some infrastructure services are leased from service providers or shared with third parties.

While some analogue technology also remains in use, we are progressively moving to digital systems to provide a communications network that better meets our future needs.

6.8.1.4 VOICE RADIO

Voice communications network is vital infrastructure ensuring that network controllers can communicate succinctly with field operators to carry out daily network operations. Our voice communication system consists of FM, E band, VHF, mobile, portable and fixed site radios operating through hilltop repeaters that are linked via a UHF repeater linking radio control from our control centre. Each of the linked repeaters can be remotely disconnected from the linkup to enable local repeater operation.

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

The current in service system is analogue, and we have developed a radio strategy to upgrade to digital systems.

6.8.2 PORTFOLIO OBJECTIVES

The SCADA asset portfolio objectives re listed in the table below.

Table 6.35 SCADA systems portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	The SCADA system enables remote operation of network assets in lieu of onsite operation.
Service levels	The SCADA system allows reliable and speedy control and monitoring of the electricity network at all times.
Cost	Consider the use of more maintenance free communications equipment to reduce the cost of maintenance.
Community	Provide timely and helpful outage information through the SCADA outage portal
Asset management capability	Migrate the existing analogue communications network infrastructure to digital platform.

6.8.3 POPULATION AND AGE STATISTICS

In recent years we have undertaken a number of projects to modernise our RTUs in order to provide acceptable levels of service. In this planning period we intend to focus on replacing any remaining legacy RTUs.

Table 6.36 summarises our population of RTUs by type. This population excludes telemetered sites with intelligent electronic devices (IEDs) directly connected to the SCADA network, such as those on modern automated reclosers.

Table 6.36 RTU population by type at 31 March 2017

Type	RTUs	% of Total
Modern	38	93
Legacy	3	7
Total	41	

At the end of our replacement programme, we will have the SCADA network standardised on the industry standard DNP3 protocol. Use of the open DNP3 standard allows direct connection of some IEDs to the SCADA master without requirement of an intermediary RTU.

Age information for our communications network is disparate, and is typically inferred from related assets or from drawings of the installations. We are working to improve our records.

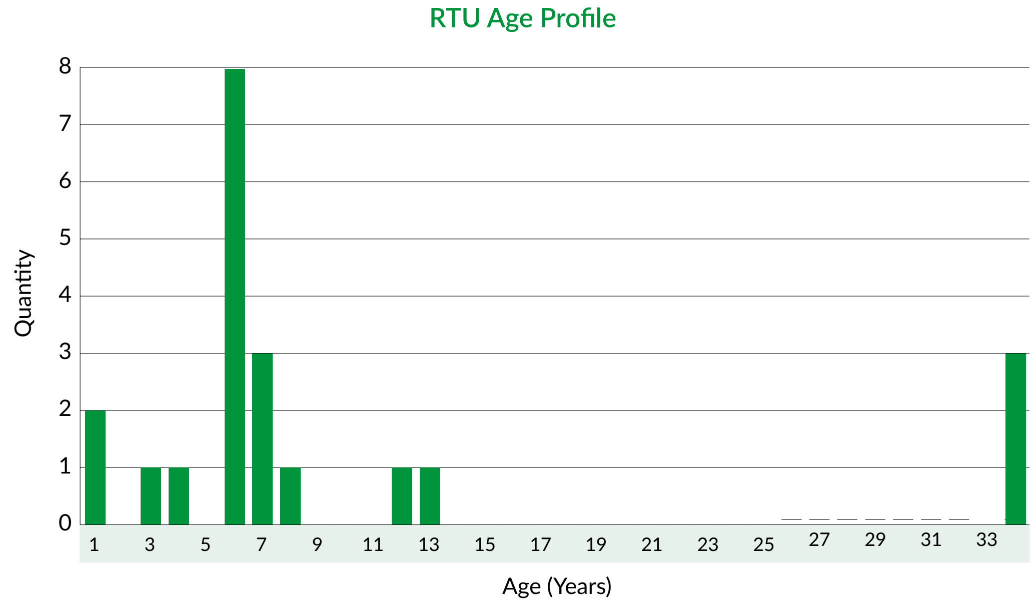


Figure 6.34 Zone substation SCADA and communications age profile

6.8.4 CONDITION, PERFORMANCE AND RISKS

The small numbers of legacy RTUs on the network are based on proprietary hardware, software and communications protocols. They cannot communicate with modern numerical relays using standard interfaces. Instead, they rely primarily on hard-wired connections which are more prone to failure, are difficult to maintain and troubleshoot, and require specialist knowledge to understand how they work. These RTUs rarely fail but a lack of experienced service personnel and original spares increases risk.

With regard to the SCADA system, the key risk is loss of network visibility and control. It is preferable to operate equipment remotely for a number of reasons, including safety, speed of operation and improved operational visibility. Lack of status information from the field can lead to switching errors such as closing on to a faulted piece of equipment or circuit.

Another significant risk is cyber-attack; a third party gaining control of our SCADA system. As more devices become visible and controllable on the network the potential safety, reliability and cost consequences from an attack on the system become increasingly serious. We continually review and improve the security of our SCADA against cyber-attack to ensure the operational safety of the network.

6.8.5 DESIGN AND CONSTRUCT

Technology changes are affecting SCADA and communications in a number of ways. As numerical protection relays and other IEDs become more prevalent and powerful, more data is collected. This requires alternative polling strategies to manage data requirements and increased communications bandwidth.

We will monitor these changes in technology closely to ensure that any benefits to our SCADA system can be promptly identified and implemented as appropriate.

The latest standard RTU types that we are installing provide remote access capability for the majority of our numerical relays. This allows our technicians and engineers to access relay and download event information remotely, removing the need to download the data at site from the relay. This could potentially reduce the time required to understand and react to a fault, thus reducing the length of power cuts for customers.

In terms of communications, moving from analogue to digital technology will allow for greater data transfer and manageability. Greater intelligence within the communications system, between IED controlled switches and the master station, will allow for automatic fault restoration.

Communications systems also enable emerging technology in other areas such as providing mobility solutions to our field workforce. Expected improvements include providing improved access to up-to-date asset information and integration with work packs.

6.8.6 OPERATE AND MAINTAIN

SCADA and communications assets are regularly inspected and tested to ensure their ongoing reliability and they remain within specifications.

Table 6.37 SCADA and communications maintenance and inspection tasks

Asset type	Maintenance and inspection task	Frequency
Communications equipment, including RTUs	General equipment inspections to test asset reliability and condition. Transmitter power checks and frequency checks. Site visual inspection for dedicated communications sites, checking building condition and ancillary services. RTU operational checks.	6 monthly
	Visual inspection of communication cables/lines, checking for condition degradation. Attenuation checks. Antennae visual inspections, with bearing and polarity verified.	1 year
SCADA master station	Apply patches.	As required

6.8.7 RENEW OR DISPOSE

SCADA and communications asset renewal is primarily based on functional obsolescence. As detailed earlier, there remains a number of legacy RTUs on the network which are based on proprietary hardware and communications protocols. They are unable to communicate through standard interfaces with modern IEDs. There is a lack of knowledgeable personnel to undertake related work and a lack of spares. Therefore the replacement of these legacy RTUs is a high priority.

Other communications assets, such as radio links and their associated hardware, are also typically replaced due to obsolescence. Modern primary assets and protection relays have the ability to collect an increasing amount of data that is useful for managing the network. To support this, legacy communication assets are replaced with modern, more functional assets. The renewal of supporting communications infrastructure such as masts and buildings is condition-based.

Our renewal forecasts are based on identifying asset types that require replacement. The renewal forecast is an estimate of the expected annual replacement quantity based on historical renewals.

In this planning period we expect an increase to SCADA and communications renewals to cater for replacement of legacy assets as well as expansion of the communications network.

ASSET MANAGEMENT PLAN // 2018

7. ASSET MANAGEMENT CAPABILITY

7. ASSET MANAGEMENT CAPABILITY

This chapter describes our asset management capability as a set of subjects that ensures assets are managed over their lifecycle in accordance with international accepted practice. These subject groups that give effect to our asset management system are: our people, information systems, strategic processes and plans, and asset data.

We also table current asset management improvement initiatives.

7.1. OUR ASSET MANAGEMENT SYSTEM

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

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

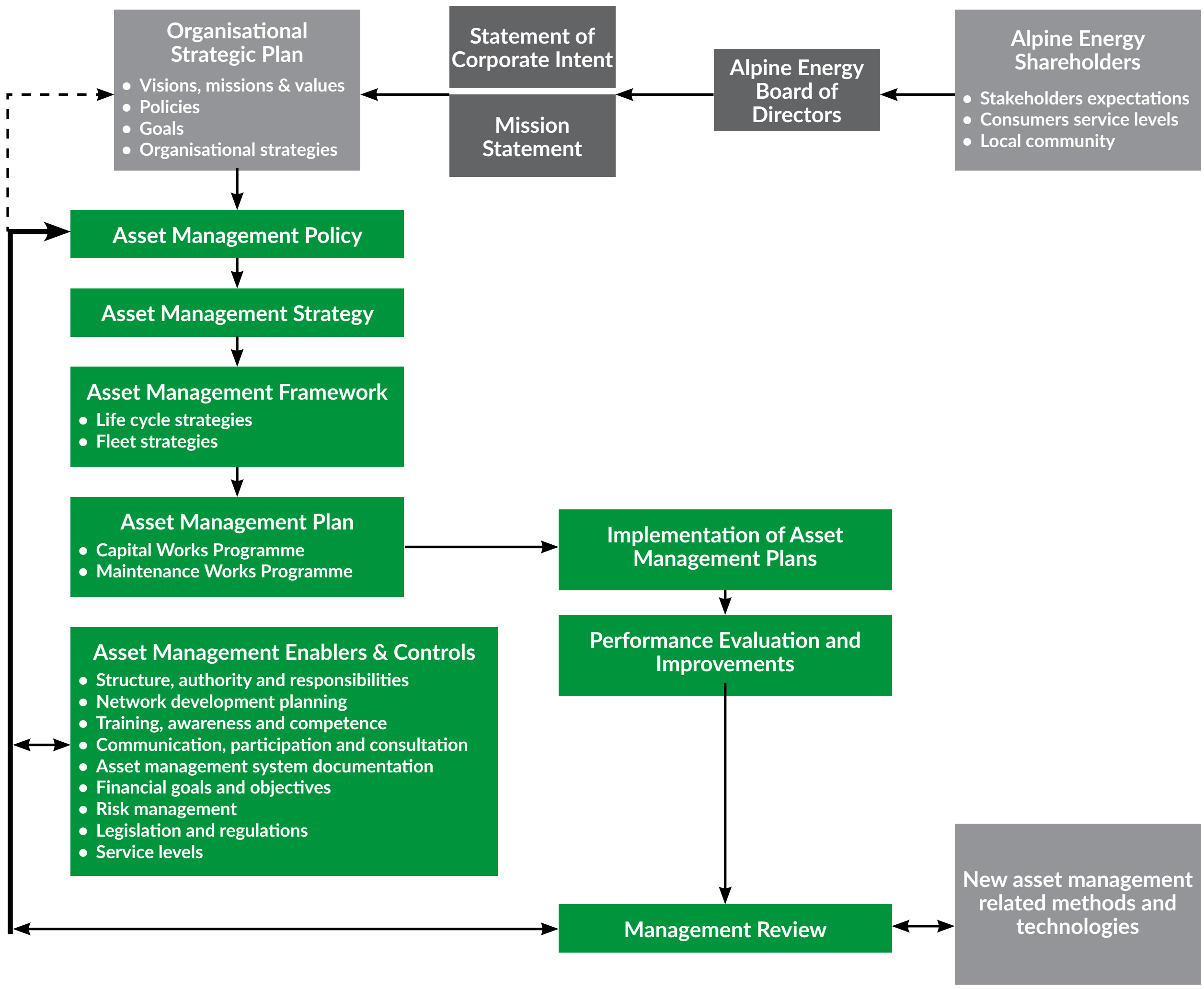


Figure 7.1 Asset management system

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

We have embarked on a journey to implement an AMF which will be an integral part of our AMS. We will use the AMF to align ourselves with the above ISO standards but not necessarily aiming to obtain certification. This framework and the journey are detailed in section 2.4. An elaboration of our AMS can be found throughout this document and includes descriptions of our strategies and policies, as well as discussions on our:

- asset databases
- system reliability
- condition assessment databases
- load flow analysis software
- maintenance records
- SCADA system
- contract management practices with external contractors
- Alliance Agreement with Netcon.

7.2. PEOPLE

Our people are our biggest asset and we recognise that the right and sufficient competencies are essential to achieve our asset management objectives. We have grown from a staff complement from thirty five in 2010 to just on eighty in 2017. This reflects not only the level of work around dairy conversions and processing on our network but also our commitment to develop good asset management practices and processes. Our main contractor Netcon is co-located on the same premises which aids in a close working relationship and prompt response to the network's needs.

We are located in Washdyke Timaru on the eastern border of our network but centrally located with respect to our infrastructure. The recent restructuring of the network departments has added some 35% additional technical and engineering resources. This together with the re-alignment of functions with the life cycle management of our assets has put us, for the first time in a position to develop and grow in asset management capability. It has been, and we still find it challenging to attract highly qualified and experienced people to South Canterbury.

In order to complete the capex works plan, we also engage consultants and external contractors from time to time. We also believe that our planned move in 2018 to a new office accommodation will aid in retaining staff.

7.3. INFORMATION SYSTEMS AND DATA

We are in the process of upgrading, replacing, and securing a number of our information technology systems (ICT), which are integral to our AMS. Our EAM system went live through the middle of 2017 and we have to date integrated basic functionality with our new GIS system. Other systems are not yet fully integrated. Consequently, individual data is often entered separately into more than one package in order to satisfy the different database and software package requirements. Where appropriate, the new system will also replace paper and spreadsheet based processes.

7.3.1. ENTERPRISE ASSET MANAGEMENT SYSTEM

The OneEnergy solution by Technology One that was implemented has replaced our financial system. Due to the complexity of the task to replace our financial system and implement a linked asset management system at the same time, we have reduced the associated risks by keeping the asset management functionality to a minimum and to use the 'out of the box' functionality and processes for the go-live stage. We are adapting current business process as much as possible to make use of the 'out of the box' functionality. There are however additional asset management functionality that we want to implement as subsequent stages in the coming years.

7.3.2. BUSINESS PROCESS MAPPING

We are and will be reviewing all of our existing business process maps as part of the introduction of the OneEnergy EAM solution. As noted above we are initially only utilising the 'out of the box' functionality and processes that OneEnergy offers which means we may have to alter/adapt some of our existing processes that will interface with or use OneEnergy. This will ensure that the processes, as they are mapped, remain relevant, effective and efficient, and, where appropriate, change the existing processes to take advantage of continuous improvements.

7.3.3. GEOSPATIAL INFORMATION SYSTEM

Our bespoke geospatial information system (GIS) has now been replaced with ESRI's ArcGIS and ArcFM configuration model and tools. The system was rolled out companywide in 2017. One of the major challenges was to incorporate all existing diagrams (schematic and general arrangement) as well as photographs related to our assets into the new system.

We have now integrated our GIS system with our EAM system. We are also in the process to integrate with our SCADA system, specifically with the OMS module to improve our outage reporting and communications.

7.3.4. SUPERVISORY CONTROL AND DATA ACQUISITION SYSTEM

Our recently upgraded SCADA system is now well embedded and productively used by the operations team. We are planning to add more functionality to this with the addition of the OMS module. This system will provide us with the following benefits:

- reduced outage durations due to faster restoration based upon outage location predictions
- reduced outage duration averages due to prioritizing
- improved consumer relations by providing accurate outage and restoration information
- ability to prioritize restoration of emergency facilities and other critical consumers
- reduced outage frequency due to use of outage statistics for making targeted reliability improvements
- fast track down of problem location by meter ping analysis with Advanced Meter Interface (AMI) interface.

7.3.5. IMPROVING ASSET KNOWLEDGE QUALITY

Effective asset management, as well as any improvements to related ICT systems, can only happen with quality data (e.g. technical asset description, age, condition, and location of assets).

The field capture of our overhead distribution system has improved the accessibility and quality of our asset data, although gaps remain. Among the improvements is the unique pole identification system, which allows field staff to reference a number from the field back to the electronic record.

Asset condition information also remains a key area for enhancement. Significant progress has been made over the recent years with condition assessments conducted by Netcon on distribution boxes and distribution transformer installations.

We are proposing to embark on a project to audit all our network assets to ensure data quality and accuracy. This project will also where applicable capture condition data.

7.3.6. DRAWING MANAGEMENT SYSTEM

During 2017 we have installed a new drawing management system (ADEPT) in response to the need for improved control and access to our Network drawings. All electronic drawings are now stored and updated in a secure auditable manner, while workflows have been implemented to manage the update process. Remaining paper based drawings will also be moved into this electronic format over the coming years. All staff within Alpine and Netcon have controlled access to drawings which are always the latest copy.

We are still in the early stages with its development and additional benefits will be realised as we move other bespoke systems such as the standards database into ADEPT and move remaining processes into an electronic workflow.

7.4. NON-NETWORK ASSETS

7.4.1. BATTERY ENERGY STORAGE

We own a relatively small battery energy storage installation connected to our network for experimentation purposes. There is a possibility that this asset may be used in a network solution to provide additional power supply at a remote location on our network. Its application is still being investigated. In developing and evaluating options for solutions to network capacity, reliability or security constraints, we consider new technologies as part of a possible solution.

Figure 7.2 Battery energy storage device

7.4.2. EV CHARGING STATIONS

Throughout the 2017/18 financial year we successfully commissioned the remaining EV fast charging units planned for South Canterbury[24]. Our network of six fast chargers now includes Waimate, Timaru, Geraldine, Fairlie, Tekapo, and Twizel. Apart from a possible unit for Mt Cook village we are not planning any further fast chargers in the short term.

7.4.3. DRONE TECHNOLOGY

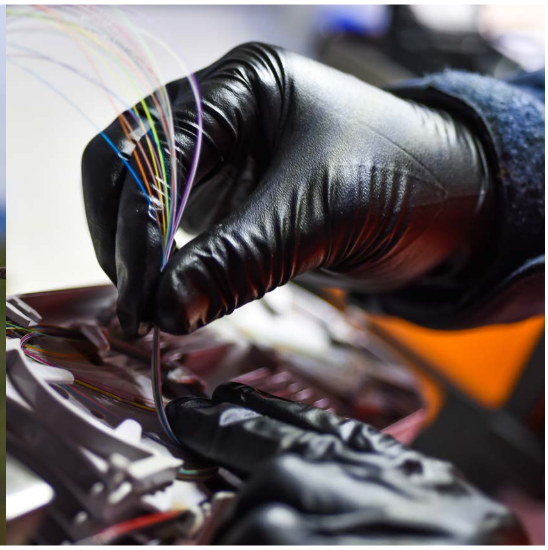
We continue to collaborate with like-minded energy companies to progress beyond visual line of sight (BVLOS) development using drone technology.

Our challenges over the years has been to reduce outages and speed up outage response times, increase public safely and staff safety, identify levels of storm / other damage quickly and efficiently, and improve vegetation management strategies.

Drone technology is seen as an evolving technology/solution to assist with us these challenges as well as complement our approach to asset condition management.

7.4.4 FIBRE

We continue to explore opportunities to extend our existing backhaul fibre network after having successfully installed and commissioned backhaul fibre[25] between Naseby to Clyde and Clyde to Alexandra. All investments are concluded on commercial terms that provide satisfactory returns while also providing diversity, redundancy, and connectivity for data traffic.



7.4.5. ADVANCED METERS AND RADIO MESH

Advanced meter deployment continues with well in excess of 50% of our metering stock changed out. Concurrent to the remaining deployment of advanced meters we are turning our attention to enhanced network benefits derived from network data captured. For the first time in our company history we are able to view power quality characteristics of our low voltage network. Prior to the use of this technology we would deploy data loggers on a case by case basis. We expect network benefits to continue to accrue over time.

Our radio mesh network in support of our advanced meter deployment was established a couple of years ago. Currently this network only supports advanced meter data collection and reporting but we are planning to also utilise this for network benefits.

7.4.6. PROPERTY

We have just completed stage one of the redevelopment of our Washdyke facility with the completion of our new office building. For the first time in seven years all of our staff will be housed in one building rather than scattered over four buildings and a number of portacoms. This will improve the communication between our various teams and departments, and improve productivity.

Stage two of the development which is budgeted for financial year 2018/19 is the redevelopment of the Washdyke yard. This will include appropriate storage and management of network equipment spares, vehicle storage and traffic management.

Figure 7.3 Alpine House

7.4.7. INFORMATION TECHNOLOGY

We are continuing our long-term strategy to invest in systems change that supports ongoing prudent decision making. In the coming year, we are implementing a project management office that will support our staff to deliver system changes under a good industry practice framework.

[24]This project does not form part of our regulated business activities.

[25] These projects does not form part of our regulated business activities.

7.5. ASSET MANAGEMENT IMPROVEMENT INITIATIVES

The development of the AMP is closely tied to the overall development of our asset management systems and processes. The implementation of the AMF development will strengthen this tie. As systems and processes mature, e.g. through the implementation of our EAM and GIS, we will be better able to communicate our systems and procedures in our AMP.

This AMP represents the third issue of a three year program to change the layout, readability and compliance of the document. Figure 7.4 below gives a summary of our current asset management maturity assessment tool (AMMAT) scores.

ALPINE ENERGY LTD AMMAT SCORE DISTRIBUTION

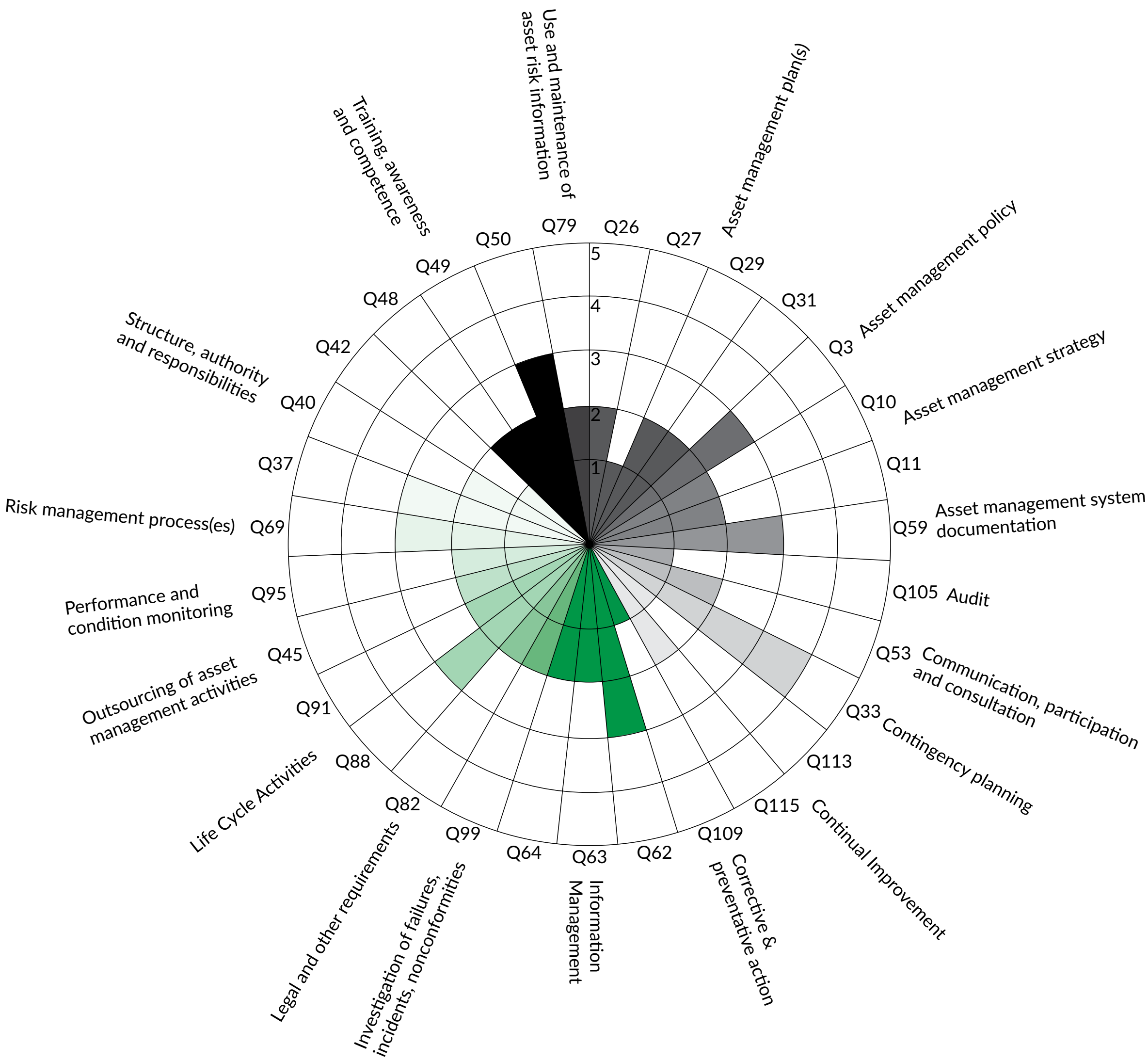


Figure 7.3 Our present AMMAT scores

7.5.1. IMPROVING AM MATURITY

We use the AMMAT assessment tool to identify current practices and improvements for our AM System. Our scores that have changed since the last reporting period are summarised in Table 7.1.

Table 7.1 AMMAT scores that have improved

Asset Management Function	Improvement Identified
Asset management policy	We have developed an asset management policy and it has been communicated to all line managers responsible for asset management.
Information management	We have identified and documented asset attributes to be stored in GIS and EAM. In addition a proposal for an asset information audit project has been submitted for budget approval and is expected to commence in 2018.
Risk management processes	We have a comprehensive Risk Management Policy describing risk matrices and management processes. Training sessions for all relevant network staff have been held to show how to use the policy. We have a Risk Committee which includes directors and who meets monthly.
Competency and training	In addition to the previous evidence of maturity in this category (see appendix A.2.7) we have also employed external experts to do an asbestos in buildings review.

7.5.2. FUTURE INITIATIVES

We have also identified improvement measures that would lift our scores in areas of greatest importance for our business. These are detailed in Table 7.2.

Table 7.2 AMMAT scores improvement initiatives

Asset Management Function	Improvement Identified	Time frame
Asset management policy	Target practice reached.	Three yearly review.
Asset management strategy	Develop performance targets and review processes.	18 months
Asset management plan(s)	Complete fleet strategies for all asset types Develop a communications plan Measure effectiveness of the communications plan Will improve as information and data modelling progresses	24 months 12 months 24 months Ongoing
Contingency planning	Establish regular testing and simulation programme.	Yearly
Structure, authority and responsibilities	Align job descriptions with AM and Portfolio objectives and strategies in this Plan. Develop a resource strategy Develop a communication plan	Yearly 24 months 12 months
Structure, authority and responsibilities	Develop a resource strategy	24 months
Communication, participation and consultation	Develop a communications plan.	12 months
Risk management process(es)	Complete all major project risk assessments in Delphi	18 months
Audit	Develop an audit plan for our AMS	Three years


ASSET MANAGEMENT PLAN // 2018

8. FINANCIAL SUMMARY

8. FINANCIAL SUMMARY

This chapter summarises our financial performance against previous budget forecasts and our expenditure forecasts for the planning period.

8.1. PERFORMANCE AGAINST PREVIOUS PLAN

Table 8.1 below shows the variance between the forecast and actual expenditure for the 2016/17 financial year. Information required by Clause 2.6.5 and Attachment A of the Information Disclosure Determination 2012 are provided in detail in the Commerce Commission Schedule 11a and 11b. A copy of the Schedule in MS Excel format is available on our website.

Table 8.1 Variance between actual and forecast expenditure in 2016/17

Variance between actual and forecast	Forecast ($'000)	Actual ($'000)	Variance %
Capital expenditure			
Customer connections	2,850	4,401	+54%
System growth	6,582	4,490	-32%
Asset replacement & renewal	7,141	9,209	+29%
Reliability, safety & environment	1,570	1,774	+13%
Subtotal – Capital expenditure on network assets	**18,573**	**19,934**	**+7%**
Operating expenditure			
Service interruptions & emergencies	1,383	1,631	+18%
Vegetation management	524	726	+39%
Asset replacement & renewal	360	181	-50%
Subtotal – Operating expenditure on network assets	**5,348**	**6,703**	**+25%**
Total expenditure on network assets	**23,924**	**26,637**	**+11%**

8.2. EXPENDITURE FORECASTS

8.2.1. CAPEX

Our current forecast for total Capex for the planning period is given in the Figure 8.1 and Table 8.2.

Both capex and opex values are expressed in constant dollar amounts (real dollars) unless otherwise specified. The values have been adjusted using an inflator of 2%[26] which approximates annual inflation for the next 10 years. Please note that opex is decreasing in real terms for the first six years of the planning period. We have decided to introduce an efficiency factor equal to the approximate inflation rate. opex is set to decrease in real terms by 2% p.a. which means that adjusting this amount by inflation each year leads to opex values that remain static for the next 6 years (in nominal terms).

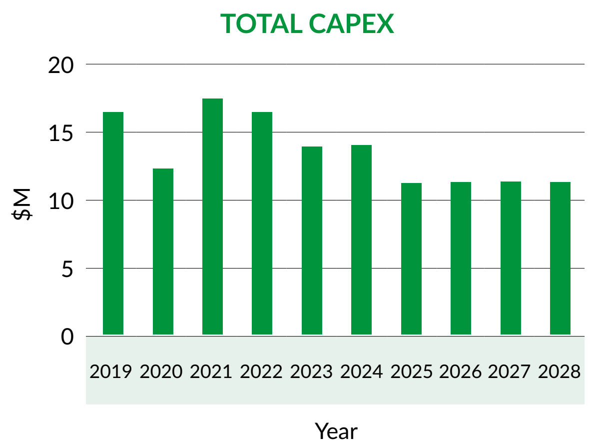


Figure 8.1 Total capex

Table 8.2 Total capex for the planning period ($ M)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
16.59	12.41	17.49	16.65	14.00	14.12	11.49	11.50	11.60	11.55

Our total capex includes the following expenditure categories:

- **Network development capex** which includes growth, customer connections, and reliability safety and environment category projects.
- **Network fleet capex** includes asset replacement and renewal as well as asset relocation projects.
- **Non-network capex** includes expenditure on smart meters, ICT infrastructure, property, equipment, and vehicles.

Totals for the above capex categories' budgets for the planning period is shown in the graphs and tables below.

[26] From most recent Treasury forecasts

8.2..11. NETWORK DEVELOPMENT CAPEX

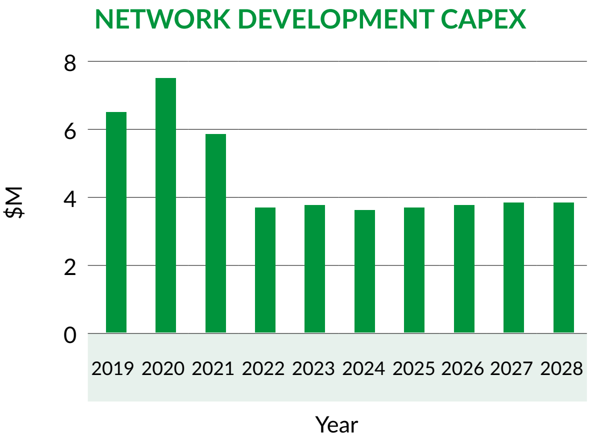


Figure 8.2 Network development capex

Table 8.3 Network development capex for the planning period ($M real 2018)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
6.61	7.58	5.94	3.82	3.87	3.77	3.82	3.87	3.92	3.92

The increased expenditure in the first three years of the planning period relates to major projects to upgrade the Balmoral zone substation, and increase transformer capacity at our Geraldine and Tekapo zone substations and the relocation/upgrade of the Twizel zone substation respectively. These major projects are mainly driven by load growth in the respective areas.

We are also considering new technologies as possible solutions for specifically the Balmoral project.

8.2.1.2. FLEET CAPEX

Our fleet capex includes expenditure on all our asset fleets namely:

- Overhead structures
- Overhead conductor
- Underground cables
- Zone substations
- Distribution transformers
- Distribution switchgear
- SCADA systems
- Asset relocations

Totals for the above capex categories' budgets for the planning period is shown in Figure 8.3 and Table 8.4.

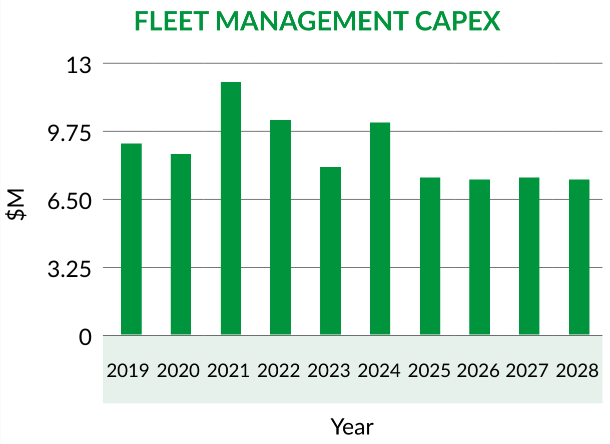


Figure 8.3 Fleet management capex

Table 8.4 Fleet management capex for the planning period ($M real 2018)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
9.08	6.938	11.86	11.63	7.93	10.15	7.47	7.425	7.47	7.41

Approximately 50% of this budget is allocated towards the renewal of our overhead structures and conductor fleet. Also worth noting is some major projects such as the renewal of our Timaru step-up zone substation in 2020-2022, the possible relocation of our Twizel zone substation in 2019-2020, and the replacement of our Tekapo zone substation switchboard in 2024.

8.2.1.3. NON-NETWORK CAPEX

Our non-network capex shows significant expenditure in the first year. This is mainly made up of the projects as detailed in Table 8.5.

Table 8.5 Non-network capex projects for 2018/19

Project / Initiative	Budget ($)
Document management system	1 M
Washdyke Yard Development	1.6 M
Asset Audit	1.4 M

Non-network capex for the planning period is given inFigure 8.4 and Table 8.6.

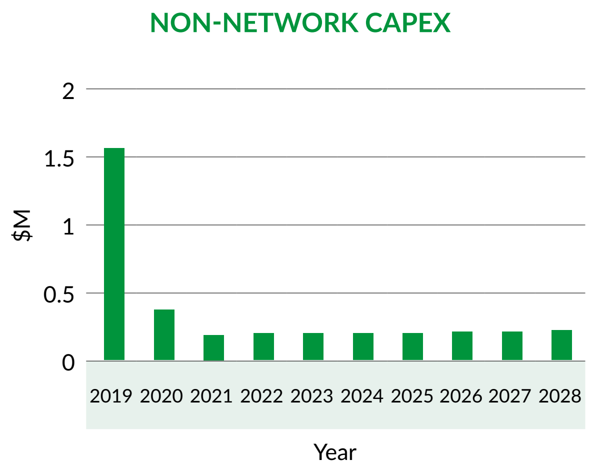


Figure 8.4 Non-network capex

Table 8.6 Non-network capex for the planning period ($M real 2018)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1.58	0.39	0.19	0.20	0.20	0.20	0.20	0.21	0.21	0.22

The IT infrastructure budget consist of two main components namely a document management system, and an asset audit projects to verify and improve the quality of our asset data as migrated from our legacy systems into TechnologyOne.

In order to fully complete our new building expenditure, the property budget above is to complete the Alpine yard development.

8.2.2. OPEX

Our total opex for the planning period is depicted in Figure 8.5 and Table 8.7.

Figure 8.5 Total opex for the planning period ($M real 2018)

Table 8.7 Total opex for the planning period ($ real 2018)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
17.22	17.15	16.73	16.54	16.34	16.12	15.90	15.70	15.61	15.48

The total opex includes the following expenditure categories:

Direct network opex which includes all expenditure on the network assets themselves, to operate and maintain,

Indirect network opex includes all the expenditure to provide systems and personnel involved in the operating, maintaining and development of the network. This is also referred to as system operations and network support (SONS).

Non-network opex includes all the ancillary services required to effectively run a distribution company including staff costs, legal costs, governance fees etc. This expenditure category is also referred to as Business Support.

8.2.2.1. DIRECT NETWORK OPEX

Figure 8.6 and Table 8.8 gives our direct network opex for the planning period.

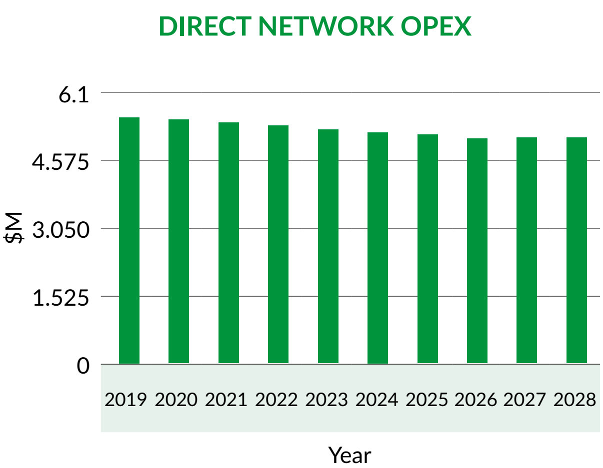


Figure 8.6 Direct network capex

Table 8.8 Direct network opex for the planning period ($M real 2018)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
5.52	5.41	5.30	5.20	5.10	5.00	4.90	4.84	4.84	4.84

We have managed to maintain our direct network opex at a constant level in real terms for the last five years and aim to continue to do so for the next five years, unless serious intervention is required due to health and safety or reliability forces us to re-evaluate. We project a slight increase in opex towards the end of the planning period accounting for the new infrastructure investments due to irrigation and dairying over the last decade.

8.2.2.2. INDIRECT NETWORK OPEX

Figure 8.7 and Table 8.9 give our indirect network opex for the planning period.

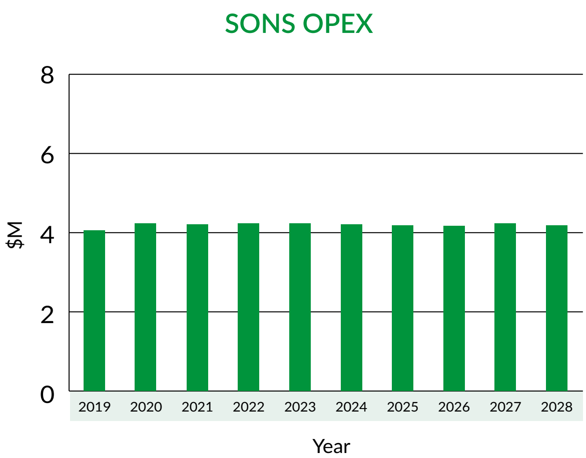


Figure 8.7 Indirect network opex for the planning period ($M real 2018)

Table 8.9 Indirect network opex for the planning period ($M real 2018)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
4.05	4.24	4.22	4.22	4.22	4.20	4.18	4.16	4.19	4.18

This expenditure category remains fairly constant over the planning period. We believe that after the re-structuring of this department in 2016, the staff complement is appropriate for the duties that are performed. Any changes for additional regulatory reporting requirements will not be material.

8.2.2.3. NON-NETWORK OPEX

Figure 8.8 and Table 8.10 gives the non-network (business support) opex for the planning period.

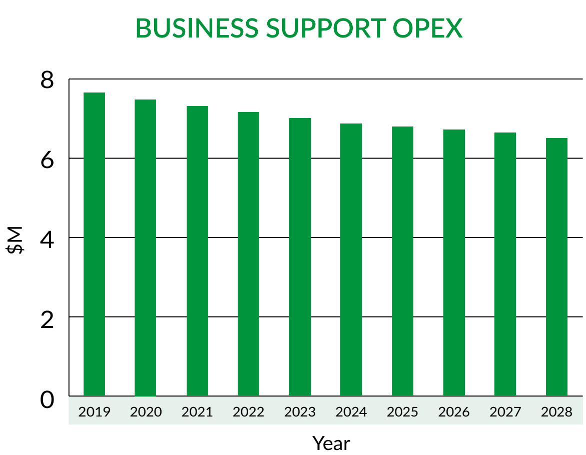


Figure 8.8 Non-network opex for the planning period ($M real 2018)

Table 8.10 Non-network opex for the planning period ($ M real 2018)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
7.66	7.50	7.20	7.12	7.02	6.92	6.82	6.70	6.58	6.45

This budget category covers all staff and operational costs for the following teams and departments:

- executive management teams.
- human resources and administration teams.
- finance / accounting team and Commercial / regulatory teams.
- property / purchasing and Information technology teams.

8.3. PLANNING PERIOD EXPENDITURE FORECAST ($'000 REAL 2018)

Expenditure Category	Actual	Forecast										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital expenditure												
Customer connections	4,401	2,200	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Growth	4,490	6,571	2,367	1,891	2,350	1.950	3,100	1,000	1.050	1,100	1,150	1,150
Replacements & Renewal	9,209	5,857	8,460	6,588	10,860	10,630	6,930	9,150	6,470	6,425	6,470	6,410
Relocations	59	2,000	620	350	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Reliability, safety & environment	1,774	1,578	1,560	1,191	1,090	870	770	770	770	770	770	770
Subtotal – Network capex	**19,934**	**18,206**	**15,007**	**12,020**	**17,300**	**16,450**	**13,800**	**13,920**	**11,290**	**11,290**	**11,390**	**11,330**
Non-network capex	3,934	12,614	1,583	391	193	197	201	201	205	209	213	217
TOTAL CAPEX	**23,868**	**30,820**	**16,590**	**12,411**	**17,493**	**16,647**	**14,001**	**14,121**	**11.495**	**11,504**	**11,603**	**11,547**
Operational expenditure												
Service interruptions & emergencies	1,631	1,344	1,380	1,353	1,327	1,301	1,301	1,301	1,301	1,301	1,301	1,301
Vegetation	726	611	598	586	575	564	552	542	531	521	510	500
Routine maintenance	4,165	3,000	3,103	3,042	2,982	2,924	2,867	2,867	2,867	2,867	2,867	2,867
Replacement & renewal	181	289	301	295	290	284	278	278	278	278	278	610
Subtotal – Network opex	**6,703**	**5,243**	**5,410**	**5,304**	**5,200**	**5,098**	**4,998**	**4,987**	**4,977**	**4,966**	**4,956**	**4,946**
Non-network opex	7,866	10,898	11,706	11,743	11,428	11,339	11,245	11,124	10,997	10,860	10,762	10,633
TOTAL OPEX	**14,569**	**15,552**	**17,116**	**17,047**	**16,628**	**16,437**	**16,243**	**16,111**	**15,974**	**15,827**	**15,718**	**15,579**
Total expenditure on assets	**38,437**	**46,372**	**33,706**	**29,458**	**34,121**	**33,084**	**30,244**	**30,232**	**27,469**	**27,331**	**27,321**	**27,126**

APPENDICES

1. GLOSSARY OF KEY TERMS

A	Ampere
AAAC	All Aluminium Alloy Conductor
AAC	All Aluminium Conductor
ABS	Air Break Switch
ABY	Albury grid exit point/zone substation
ACSR	Aluminium Conductor Steel Reinforced
ADMD	After Diversity Maximum Demand
AHP	Analytical Hierarchical Process
AMF	Asset Management Framework
AMG	Alpine Mobile Generator – 2 x 900 kVA (1 MW effective)
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
AMS	Alpine Mobile Substation – 33/11 kV (9 MVA effective)
AMS	Asset Management System
BML	Balmoral Zone Substation
BPD	Bell's Pond grid exit point/zone substation
Capex	Capital Expenditure
CB	Circuit Breaker
CBD	Central Business District
CD1	Clandeboye No.1 zone substation
CD2	Clandeboye No.2 zone substation
CPD	Coincident peak demand
Cu	Copper
DNP	Direct Numeric Protocol
DO	Drop Out fuse
EAM	Enterprise Asset Management
EC	Electricity Commission
EDB	NZ Electricity Distribution Businesses
EEA	Electricity Engineers' Association
EF	Earth Fault
FLE	Fairlie zone substation
GIS	Geographic Information System
GLD	Geraldine Downs zone substation
GRM	Grasmere switching substation
GWh	Giga Watt hours
GXP	Grid Exit Point
HNT	Hunt Street switching substation
HV	High Voltage

Hz	Hertz (a measure of frequency)
ICP	Installation Control Point
ICT	Information and Communications Technology
ID	Information Disclosure
IPCC	Intergovernmental Panel on Climate Change
ISL–LIV	Islington Livingston
kV	kilo Volt
kVA	kilo Volt Ampere
LV	Low Voltage
MDC	Mackenzie District Council
MVA	Mega Volt Ampere
MW	Mega Watt
N-1	Security of supply measure, where n systems can lose 1 element and still function normally
NSP	Network Supply Points
NST	North Street switching substation
NWL	Network Waitaki Limited
OCB	Oil Circuit Breaker
ODL	Oceania Dairy Limited
ODV	Optimised Deprival Valuation
OLTC	On Load Tap Changer
OMS	Outage Management System
Opex	Operating Expenditure (including maintenance spend)
PAR	Pareora zone substation
PAS 55:2008	Publicly Available Specification number 55
PILC	Paper Insulated Lead Cable
PILCSWA	Paper Insulated Lead Steel Wire Armoured cable
PLP	Pleasant Point zone substation
RGA	Rangitata zone substation
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
SIE	System Interruptions and Emergencies
SONS	System Operations and Network Support
STU	Studholme grid exit point/zone substation
TDC	Timaru District Council
TEK	Tekapo Village zone substation
TIM	Timaru grid exit point/step-up zone substation
TKA	Tekapo grid exit point

TMK	Temuka grid exit point/zone substation
TP	Transpower
TVS	Twizel Village zone substation
TWZ	Twizel grid exit point
UHT	Unwin Hut zone substation
V	Volts
VCB	Vacuum Circuit Breaker
W	Watts
WDC	Waimate District Council
XLPE	Cross Linked Polyethylene Cable

2. DISCLOSURE SCHEDULES

COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements

Information Templates

for

Schedules 11a–13

Company Name	Alpine Energy Limited
Disclosure Date	31 March 2018
AMP Planning Period Start Date (first day)	1 April 2018

Templates for Schedules 11a–13 (Asset Management Plan)
Template Version 4.1. Prepared 24 March 2015

Table of Contents

Information disclosure asset management plan schedules

Schedule	Schedule name
11a	REPORT ON FORECAST CAPITAL EXPENDITURE
11b	REPORT ON FORECAST OPERATIONAL EXPENDITURE
12a	REPORT ON ASSET CONDITION
12b	REPORT ON FORECAST CAPACITY
12c	REPORT ON FORECAST NETWORK DEMAND
12d	REPORT FORECAST INTERRUPTIONS AND DURATION
13	REPORT ON ASSET MANAGEMENT MATURITY

Disclosure Template Instructions

These templates have been prepared for use by EDBs when making disclosures under subclauses 2.6.1(1)(d), 2.6.1(1)(e), 2.6.1(2), 2.6.5(6), 2.6.6(1) and 2.6.6(2) of the Electricity Distribution Information Disclosure Determination 2012. The EDB may include a completed Schedule 13: Report on Asset Management Maturity table with its disclosures made under subclause 2.6.6(1) and 2.6.6(2), but this is not required. Schedule 13 tables that are not completed should be removed from disclosures made under subclause 2.6.6(1) and 2.6.6(2).

Company Name and Dates

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the first day of the 10 year planning period should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.
The cell C12 entry (planning period start date) is used to calculate disclosure years in the column headings that show above some of the tables. It is also used to calculate the AMP planning period dates in the template title blocks (the title blocks are the light green shaded areas at the top of each template).
The cell C8 entry (company name) is used in the template title blocks.
Dates should be entered in day/month/year order (Example -"1 April 2013").

Data Entry Cells and Calculated Cells

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.
In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell.

Validation Settings on Data Entry Cells

To maintain a consistency of format and to guard against errors in data entry, some data entry cells test entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names or to values between 0% and 100%.
Where this occurs, a validation message will appear when data is being entered.

Conditional Formatting Settings on Data Entry Cells

Schedule 12a columns G to K contains conditional formatting. The cells will change colour if the row totals do not add to 100%.

Inserting Additional Rows

The templates for schedules 11a, 12b and 12c may require additional rows to be inserted in tables marked 'include additional rows if needed'.
Additional rows must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.
For schedule 12b the formula for column J (Utilisation of Installed Firm Capacity %) will need to be copied into the inserted row(s).
Column A schedule references should not be entered in additional rows.

Schedule References

The references labelled 'sch ref' in the leftmost column of each template are consistent with the row references in the Electricity Distribution ID Determination 2012 (as issued on 24 March 2015). They provide a common reference between the rows in the determination and the template.

Description of Calculation References

Calculation cell formulas contain links to other cells within the same template or elsewhere in the workbook. Key cell references are described in a column to the right of each template. These descriptions are provided to assist data entry. Cell references refer to the row of the template and not the schedule reference.

Company Name: **Alpine Energy Limited**
AMP Planning Period: **1 April 2018 – 31 March 2028**

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 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	2,850	2,040	2,044	2,122	2,165	2,208	2,252	2,297	2,343	2,390	2,438
11		System growth	2,851	2,414	1,933	2,494	2,111	3,423	1,126	1,206	1,289	1,374	1,402
12		Asset replacement and renewal	2,852	8,629	6,733	11,525	11,506	7,651	10,304	7,432	7,528	7,732	7,814
13		Asset relocations	2,853	632	358	1,061	1,082	1,104	1,126	1,149	1,172	1,195	1,219
14		Reliability, safety and environment:											
15		Quality of supply	840	995	741	679	563	574	586	597	609	621	634
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	730	597	476	478	379	276	282	287	293	299	305
18		**Total reliability, safety and environment**	1,570	1,591	1,217	1,157	942	850	867	884	902	920	939
19		**Expenditure on network assets**	12,976	15,307	12,284	18,359	17,806	15,236	15,676	12,969	13,234	13,612	13,811
20		Expenditure on non-network assets	12,161	1,615	407	205	213	221	226	235	244	254	265
21		**Expenditure on assets**	25,137	16,922	12,692	18,563	18,019	15,458	15,902	13,204	13,478	13,866	14,076
22													
23	*plus*	Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less*	Value of capital contributions	2,684	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	22,453	14,922	10,692	16,563	16,019	13,458	13,902	11,204	11,478	11,866	12,076
28													
29		Assets commissioned	20,766	21,003	10,681	15,722	14,874	12,183	12,378	9,746	9,631	9,930	9,753

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
31		for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
32			**$000 (in constant prices)**										
33		Consumer connection	2,200	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
34		System growth	6,571	2,367	1,891	2,350	1,950	3,100	1,000	1,050	1,100	1,150	1,150
35		Asset replacement and renewal	5,857	8,460	6,588	10,860	10,630	6,930	9,150	6,470	6,425	6,470	6,410
36		Asset relocations	2,000	620	350	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
37		Reliability, safety and environment:											
38		Quality of supply	630	975	725	640	520	520	520	520	520	520	520
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	400	585	466	450	350	250	250	250	250	250	250
41		**Total reliability, safety and environment**	1,030	1,560	1,191	1,090	870	770	770	770	770	770	770
42		**Expenditure on network assets**	17,658	15,007	12,020	17,300	16,450	13,800	13,920	11,290	11,295	11,390	11,330
43		Expenditure on non-network assets	12,161	1,583	391	193	197	201	201	205	209	213	217
44		**Expenditure on assets**	29,818	16,590	12,411	17,493	16,647	14,001	14,121	11,495	11,504	11,603	11,547
45													
46		**Subcomponents of expenditure on assets (where known)**											
47		Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48		Overhead to underground conversion	2,000	620	350	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
49		Research and development	-	-	-	-	-	-	-	-	-	-	-

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2018 – 31 March 2028**

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
50												
51–52	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	650	40	44	122	165	208	252	297	343	390	438
55	System growth	(3,720)	47	42	144	161	323	126	156	189	224	252
56	Asset replacement and renewal	(3,005)	169	145	665	876	721	1,154	962	1,103	1,262	1,404
57	Asset relocations	853	12	8	61	82	104	126	149	172	195	219
58	Reliability, safety and environment:											
59	Quality of supply	210	20	16	39	43	54	66	77	89	101	114
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	330	12	10	28	29	26	32	37	43	49	55
62	**Total reliability, safety and environment**	540	31	26	67	72	80	97	114	132	150	169
63	**Expenditure on network assets**	(4,682)	300	264	1,059	1,356	1,436	1,756	1,679	1,939	2,222	2,481
64	Expenditure on non-network assets	-	32	16	12	16	21	25	30	36	42	48
65	**Expenditure on assets**	(4,682)	332	280	1,071	1,372	1,457	1,781	1,709	1,975	2,264	2,529
66												

11a(ii): Consumer Connection

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
67	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	**$000 (in constant prices)**					
70	Low User Charge	110	100	100	100	100	100
71	015	308	280	280	280	280	280
72	360	264	240	240	240	240	240
	Assessed	506	460	460	460	460	460
	TOU 400V	1,012	920	920	920	920	920
73	TOU 11kV	-	-	-	-	-	-
74	IND	-	-	-	-	-	-
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	2,200	2,000	2,000	2,000	2,000	2,000
77	*less* Capital contributions funding consumer connection	318	1,500	1,500	1,500	1,500	1,500
78	**Consumer connection less capital contributions**	1,882	500	500	500	500	500

11a(iii): System Growth

79	**11a(iii): System Growth**						
80	Subtransmission	-	-	-	-	-	-
81	Zone substations	4,150	1,570	-	1,500	1,000	2,000
82	Distribution and LV lines	-	-	400	150	250	350
83	Distribution and LV cables	990	300	300	300	300	300
84	Distribution substations and transformers	670	247	236	100	100	100
85	Distribution switchgear	391	150	150	150	150	150
86	Other network assets	370	100	805	150	150	200
87	**System growth expenditure**	6,571	2,367	1,891	2,350	1,950	3,100
88	*less* Capital contributions funding system growth	950	300	300	300	300	300
89	**System growth less capital contributions**	5,621	2,067	1,591	2,050	1,650	2,800
90							

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2018 – 31 March 2028**

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
92		for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
93	**11a(iv): Asset Replacement and Renewal**		$000 (in constant prices)					
94	Subtransmission		-	344	200	-	-	-
95	Zone substations		450	855	600	4,150	3,900	200
96	Distribution and LV lines		3,522	3,714	3,336	4,140	4,240	4,240
97	Distribution and LV cables		300	800	350	800	800	800
98	Distribution substations and transformers		400	1,455	1,130	1,120	1,020	1,020
99	Distribution switchgear		400	542	522	400	420	420
100	Other network assets		785	750	450	250	250	250
101	**Asset replacement and renewal expenditure**		5,857	8,460	6,588	10,860	10,630	6,930
102	*less* Capital contributions funding asset replacement and renewal		847	200	200	200	200	200
103	**Asset replacement and renewal less capital contributions**		5,010	8,260	6,388	10,660	10,430	6,730
104								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
107	**11a(v):Asset Relocations**							
108	*Project or programme**		$000 (in constant prices)					
109	O/H to U/G conversions		2,000	620	350	1,000	1,000	1,000
110								
111								
112								
113								
114	**include additional rows if needed*							
115	All other project or programmes - asset relocations		-	-	-	-	-	-
116	**Asset relocations expenditure**		2,000	620	350	1,000	1,000	1,000
117	*less* Capital contributions funding asset relocations		289	-	-	-	-	-
118	**Asset relocations less capital contributions**		1,711	620	350	1,000	1,000	1,000
119								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
122	**11a(vi):Quality of Supply**							
123	*Project or programme**		$000 (in constant prices)					
124	New ABSs & automated devices		120	120	120	120	120	120
125	Reclosers New		100	300	300	300	300	300
	Mobile sub/gen site preparations		250	250	120	120	-	-
	SCADA & pole top equipment automation (e.g. reclos		160	160	100	100	100	100
126	Motorised LBS		-	85	85	-	-	-
127	Second 11 kV AMS connection at TEK		-	60	-	-	-	-
129	**include additional rows if needed*							
130	All other projects or programmes - quality of supply		-	-	-	-	-	-
131	**Quality of supply expenditure**		630	975	725	640	520	520
132	*less* Capital contributions funding quality of supply		129	-	-	-	-	-
133	**Quality of supply less capital contributions**		501	975	725	640	520	520
134								

Company Name	Alpine Energy Limited
AMP Planning Period	1 April 2018 – 31 March 2028

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	$000 (in constant prices)					
139	[Description of material project or programme]						
140	[Description of material project or programme]						
141	[Description of material project or programme]						
142	[Description of material project or programme]						
143	[Description of material project or programme]						
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							
150	for year ended	Current Year CY 31 Mar 18	CY+1 31 Mar 19	CY+2 31 Mar 20	CY+3 31 Mar 21	CY+4 31 Mar 22	CY+5 31 Mar 23
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	$000 (in constant prices)					
153	New RMUs	100	100	100	100	100	100
154	Abloy locks	250	250	100	200	100	-
155	SCADA Master Station Modules	50	30	200	150	150	150
156							
157							
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment	-	205	66	-	-	-
160	**Other reliability, safety and environment expenditure**	400	585	466	450	350	250
161	*less* Capital contributions funding other reliability, safety and environment	99	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	301	585	466	450	350	250
163							
164		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	$000 (in constant prices)					
169	IT	2,569	151	154	115	117	119
170	Equipment	2,286	277	177	78	80	81
171	Vehicles	60	-	60	-	-	-
172							
173							
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure	-	-	-	-	-	-
176	**Routine expenditure**	4,916	428	391	193	197	201
177	**Atypical expenditure**						
178	*Project or programme**						
179	Property	7,245	1,155	-	-	-	-
180							
181							
182							
183							
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure	-	-	-	-	-	-
186	**Atypical expenditure**	7,245	1,155	-	-	-	-
187							
188	**Expenditure on non-network assets**	12,161	1,583	391	193	197	201

Company Name: **Alpine Energy Limited**

AMP Planning Period: **1 April 2018 – 31 March 2028**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,370	1,436	1,436	1,436	1,436	1,436	1,465	1,494	1,524	1,555	1,586
11	Vegetation management	623	610	610	610	610	610	610	610	610	610	610
12	Routine and corrective maintenance and inspection	3,060	3,165	3,165	3,165	3,165	3,165	3,228	3,293	3,359	3,426	3,494
13	Asset replacement and renewal	295	307	307	307	307	307	313	320	326	333	339
14	**Network Opex**	5,348	5,519	5,519	5,519	5,519	5,519	5,617	5,717	5,819	5,923	6,029
15	System operations and network support	4,329	4,129	4,410	4,482	4,570	4,661	4,733	4,803	4,879	5,003	5,094
16	Business support	6,568	7,810	7,808	7,646	7,703	7,754	7,794	7,829	7,846	7,859	7,867
17	**Non-network opex**	10,898	11,940	12,217	12,128	12,273	12,415	12,527	12,632	12,725	12,861	12,962
18	**Operational expenditure**	16,246	17,458	17,736	17,646	17,792	17,934	18,144	18,349	18,544	18,785	18,991

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
20	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,344	1,408	1,380	1,353	1,327	1,301	1,301	1,301	1,301	1,301	1,301
23	Vegetation management	611	598	586	575	564	552	542	531	521	510	500
24	Routine and corrective maintenance and inspection	3,000	3,103	3,042	2,982	2,924	2,867	2,867	2,867	2,867	2,867	2,867
25	Asset replacement and renewal	289	301	295	290	284	278	278	278	278	278	278
26	**Network Opex**	5,243	5,410	5,304	5,200	5,098	4,998	4,987	4,977	4,966	4,956	4,946
27	System operations and network support	4,329	4,048	4,239	4,223	4,222	4,221	4,203	4,182	4,164	4,186	4,179
28	Business support	6,568	7,657	7,504	7,205	7,117	7,023	6,921	6,816	6,696	6,576	6,454
29	**Non-network opex**	10,898	11,706	11,743	11,428	11,339	11,245	11,124	10,997	10,860	10,762	10,633
30	**Operational expenditure**	16,141	17,116	17,047	16,628	16,437	16,243	16,111	15,974	15,827	15,718	15,579
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	202	214	214	214	214	214	214	214	214	214	214

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

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
40	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	27	28	56	83	109	135	164	193	223	254	285
43	Vegetation management	12	12	24	35	46	58	68	79	89	100	110
44	Routine and corrective maintenance and inspection	60	62	123	183	241	298	362	426	492	559	628
45	Asset replacement and renewal	6	6	12	18	23	29	35	41	48	54	61
46	**Network Opex**	105	108	214	318	420	520	629	740	853	967	1,083
47	System operations and network support	-	81	171	259	348	439	530	622	715	817	915
48	Business support	-	153	303	441	587	731	873	1,013	1,149	1,283	1,413
49	**Non-network opex**	-	234	474	699	935	1,170	1,403	1,635	1,864	2,100	2,329
50	**Operational expenditure**	105	342	689	1,018	1,355	1,691	2,033	2,375	2,717	3,066	3,412

Company Name: **Alpine Energy Limited**

AMP Planning Period: **1 April 2018 – 31 March 2028**

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	Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade)						
7											
8					Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	4.43%	11.00%	73.80%	10.77%	-	3	4.43%
11	All	Overhead Line	Wood poles	No.	9.85%	8.33%	74.62%	7.21%	-	3	9.85%
~~12~~	~~All~~	~~Overhead Line~~	~~Other pole types~~	~~No.~~						[Select one]	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	0.20%	69.00%	30.80%	-	3	0.50%
~~14~~	~~HV~~	~~Subtransmission Line~~	~~Subtransmission OH 110kV+ conductor~~	~~km~~						[Select one]	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	9.25%	90.75%	-	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.	-	3.70%	40.70%	55.60%	-	3	
~~25~~	~~HV~~	~~Zone substation Buildings~~	~~Zone substations 110kV+~~	~~No.~~						[Select one]	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.				100.00%		4	
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	14.29%	28.57%	28.57%	28.57%	-	3	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.					100.00%	1	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.					100.00%	1	
~~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%		4	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	7.00%	45.00%	48.00%	-	3	5.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-		100.00%	-	3	
35											

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2018 – 31 March 2028**

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)						
36											
37											
38	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	1.00%	34.00%	65.00%	-	3	1.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.12%	0.88%	72.00%	27.00%	-	2	1.00%
~~41~~	~~HV~~	~~Distribution Line~~	~~Distribution OH Aerial Cable Conductor~~	~~km~~						[Select one]	
~~42~~	~~HV~~	~~Distribution Line~~	~~SWER conductor~~	~~km~~						[Select one]	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	12.58%	87.42%	-	2	
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	92.73%	7.27%	-	2	
~~45~~	~~HV~~	~~Distribution Cable~~	~~Distribution Submarine Cable~~	~~km~~						[Select one]	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	2.30%	4.60%	32.10%	61.00%	-	3	4.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.					100.00%	1	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.90%	2.60%	64.50%	32.00%	-	2	3.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	0.90%	2.60%	64.50%	32.00%	-	2	3.00%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	3.20%	61.00%	32.00%	3.80%	3	6.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.40%	1.20%	83.00%	15.40%	-	2	2.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	4.61%	2.69%	33.80%	58.90%	-	3	4.61%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	3.00%	97.00%	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.					100.00%	1	
55	LV	LV Line	LV OH Conductor	km	0.10%	0.40%	79.00%	20.50%	-	2	1.00%
56	LV	LV Cable	LV UG Cable	km	10.74%	10.01%	48.77%	30.47%	-	3	10.74%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.10%	0.40%	79.00%	20.50%	-	2	1.00%
58	LV	Connections	OH/UG consumer service connections	No.					100.00%	1	
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	8.70%	4.30%	87.00%	-	3	
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	12.50%	-	87.50%	-	3	
61	All	Capacitor Banks	Capacitors including controls	No.				100.00%		1	
62	All	Load Control	Centralised plant	Lot	-	50.00%	16.70%	33.30%	-	3	16.70%
63	All	Load Control	Relays	No.	0.18%	6.26%	13.48%	29.50%	50.58%	1	0.18%
64	All	Civils	Cable Tunnels	km				100.00%		3	

Company Name **Alpine Energy Limited**

AMP Planning Period **1 April 2018 – 31 March 2028**

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 (ABY)	4.92	-	N	-	-	-	-		No firm capacity increase planned
10	Balmoral (BML)	0.13	-	N	-	-	-	-		No firm capacity increase planned
11	Bell's Pond (BPD)	12.49	20.00	N-1	-	62%	20	58%	No constraint within +5 years	T2 HV winding rating, T1 installed in FY 18/19
12	Clandeboye 1 (CD1)	15.41	20.00	N-1	-	77%	20	86%	No constraint within +5 years	Load from SCADA, step demand increase 2020
13	Clandeboye 2 (CD2)	15.95	25.00	N-1	-	64%	25	60%	No constraint within +5 years	Load from SCADA, step demand increase 2020
14	Cooney's Road (CNR)	3.48	-	N	1.8/0.8/0.6*	-	-	-		No firm capacity increase planned
15	Fairlie (FLE)	2.58	-	N	-	-	-	-		No firm capacity increase planned
16	Geraldine (GLD)	6.70	-	N	-	-	-	-		No firm capacity increase planned
17	Haldon Lilybank (HLB)	0.51	-	N	-	-	-	-		No firm capacity increase planned, Load is calculated value
18	Pareora (PAR)	9.15	15.00	N-1	-	61%	15	58%	No constraint within +5 years	Load transfer fron STU & TIM, Hunter Downs Water
19	Pleasant Point (PLP)	5.12	-	N	-	-	-	-		No firm capacity increase planned
20	Rangitata (RGA)	9.57	10.00	N-1 switched	-	96%	10	98%	Subtransmission circuit	Line capacity constraint.
21	Studholme (STU)	16.42	11.00	N-1	-	149%	11	126%	Transformer	Transpower two 11 MVA transformers, Load shedding or shift required
22	Tekapo Village (TEK)	2.86	-	N	-	-	-	-		No firm capacity increase planned
23	Temuka (TMK)	13.63	25.00	N-1	-	55%	25	56%	No constraint within +5 years	Transfer from TIM, CD1, GLD & TMK
24	Timaru 11/33 (TIM)	14.14	25.00	N-1	-	57%	25	19%	No constraint within +5 years	Hunter Downs Water
25	Twizel Village (TVS)	3.43	-	N	-	-	-	-		No firm capacity planned
26	Unwin Hut (UHT)	1.05	-	N	-	-	-	-		No firm capacity planned.
27	[Zone Substation_19]					-				
28	[Zone Substation_20]					-				

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

Company Name	Alpine Energy Limited
AMP Planning Period	1 April 2018 – 31 March 2028

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

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

sch ref							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
11	*Consumer types defined by EDB**						
12	Low Charge	9,980	10,071	10,172	10,275	10,379	10,483
	Low Uncontrolled	35	35	36	36	36	37
	015	19,680	19,859	20,059	20,261	20,466	20,672
	015 Uncontrolled	76	78	78	79	80	81
	360	1,234	1,245	1,258	1,270	1,283	1,296
	360 Uncontrolled	33	24	24	25	25	25
13	Assessed	1,637	1,695	1,712	1,729	1,747	1,764
14	TOU 400V	142	142	144	145	147	148
15	TOU 11kV	10	10	10	10	10	10
16	IND	6	6	6	6	6	6
17	**Connections total**	32,833	33,165	33,499	33,837	34,179	34,523
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	225	346	467	588	709	830
21	Capacity of distributed generation installed in year (MVA)	1	1	1	1	1	1
22	**12c(ii) System Demand**						
23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** — for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
25	GXP demand	134	149	167	181	184	187
26	*plus* Distributed generation output at HV and above	7	7	7	7	7	7
27	**Maximum coincident system demand**	140	155	173	187	191	194
28	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	140	155	173	187	191	194
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	853	871	889	906	924	942
32	*less* Electricity exports to GXPs	6	6	6	6	6	6
33	*plus* Electricity supplied from distributed generation	13	13	14	14	14	14
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**	861	879	896	914	932	950
36	*less* Total energy delivered to ICPs	845	863	880	898	916	933
37	**Losses**	15	16	16	16	17	17
38							
39	**Load factor**	70%	65%	59%	56%	56%	56%
40	**Loss ratio**	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%

Company Name **Alpine Energy Limited**
AMP Planning Period **1 April 2018 – 31 March 2028**
Network / Sub-network Name

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
10	**SAIDI**						
11	Class B (planned interruptions on the network)	46.2	46.2	46.2	45.8	45.8	45.8
12	Class C (unplanned interruptions on the network)	107.9	107.9	107.9	106.8	106.8	106.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.45	0.45	0.45	0.45	0.45	0.45
15	Class C (unplanned interruptions on the network)	1.05	1.05	1.05	1.04	1.04	1.04

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Asset Management Standard Applied	

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?	3	Asset management policy	We have implemented an asset management policy as part of the development of our AMF. All network managers have been made aware of this policy.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, 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?	2	AM Policy, AM Strategy	AM strategy is available, aligns with AM policy, as well as other policies. Strategic objectives identified and documented.	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 (eg, 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?	2	Within the asset management framework (see section 4.1) life cycle strategies for planning, maintenance, operations and delivery are in in draft format.	The fourth tier of the asset management framework will detail fleet strategies of all asset types including non-network assets. Currently parts of this are contained in Chapter 7 of the 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	We have implemented our EAM system and integrated it with our GIS. We are in the process of setting up maintenance schedules for all asset types.	We are developing our AMS which includes completing our AMF, and maintenance schedules for all asset types. When the AMF is completed the AMP will better reflect the life cycle activities of all assets.	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).

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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
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?	1	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. Specific accountabilities for the AMP are detailed in all relevant staff position descriptions.	We circulate a copy of our AMP to our principle contractor, shareholders, large consumers, and key staff. A copy of our AMP is available, at reception and on our website. We do not, however, meet with large consumers or other smaller contractors; nor do we present all staff with the key components of the AMP. We leave it to stakeholders to read and interpret the AMP themselves.	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	Alliance Agreement with NETcon Position descriptions Standard formsfo contract ie. NZ 3910	Our recent network department restructure is based, in terms of the various teams, on all the asset life cycle stages. New position descriptions were developed for these roles. The majority of which also serves on the Alliance management team, as part of the Alliance agreement. All external contracts for major projects are conducted under a standard form of contract, mainly NZ 3910 and in one instance in the past under the NEC3 form of contract.	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	We involve our main service provider during the planning phase for the upcoming works program. We have fortnightly progress and planning meetings where we discuss the works program and ensure all relevant teams and departments are informed. All major projects are priced by our service providers for evaluation before jobs are issued. All projects and jobs are captured against relevant assets within out EAM system. We have an Alliance Agreement with our main service provider (Netcon) re works program delivery. Business Process Maps have been developed for our new EAM system. 2. NETcon Purchase order 3. NETcon Alliance Agreement 4. Job descriptions for senior management 5. Our AMP 6. Business Process Mapping (BPM) of processes 7. Board papers approving unplanned	Since 2005 we have recruited additional staff to ensure that our work plan can be completed. For example, in 2005 we had one network engineer and eight support staff. In 2012 we had grown to six network engineers and twelve support staff. The Board approves unplanned works and notes monthly variances between budgeted and actual expenditure.	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?	4	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. 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.	We have a comprehensive Emergency Preparedness Plan in place which supports us to manage the continuity of critical asset management activity in an emergency event. Our plan is part of our Public Safety Management System which ensures consistency between our policies and strategies around asset management objectives.	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	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)?	3	1. Detailed position descriptions for the GM_Network and all direct reports 2. Chapter 2 of our AMP includes detailed discussion of our accountabilities for asset management 3. AEL Organisational Chart 4. BPMs 5. Safety Management System audit reports 6. Board meeting minutes on staffing levels and current / future competency requirements 7. Alliance Agreement with NETcon. 8. Our AMF as detailed in section 4.2 of the AMP. 2. Chapter 2 of our AMP includes detailed discussion of our accountabilities for asset management 3. AEL Organisational Chart 4. BPM of processes 5. Safety Management System audit	The roles and responsibilities, selection criteria and review processes for the appointment of members of the asset management team are documented but not reviewed against strategies and objectives.	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 eg, 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?	2	1. Alliance Agreement with NETcon 2. AMP, chapter 2 3. BPM of HR processes 4. Board reports and meeting minutes discussing budgets, variance analysis, staff structures/requirements, and CAPEX and OPEX spending	Our new network department structure and associated position descriptions, our recent procurement and current implementation of EAM, GIS and SCADA systems. Expansion of our ICT team.	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?	1	1.Schedule 13 Senior management meeting notes 2. Network meeting notes 3. Job descriptions of senior management 4. Board reports and meeting minutes 5. Alliance Agreement meetings 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.	Network CAPEX and OPEX are covered as standing agenda items on the fort nightly Network managers' meetings. The delivery program is the main agenda item on the Alliance agreement meetings. Monthly expenditure is captured in the board report .	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 (eg, 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 Alliance Agreement 2. Spread sheets for maintenance status of capacitors, reclosers, regulators, substations, etc. 3. TechnologyOne accounting software generate automated reports 4. New connection sign off sheets. 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.	We have an Alliance Agreement with our preferred contractor, NETcon. The Alliance management team meet weekly to discuss performance, operational progress and other relevant issues. The meetings are recorded in meeting minutes. The Alliance has a suite of management and control documents in place. As the Alliance grows in maturity this score will improve.	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 (eg, 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	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)?	2	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.	Our new network department structure with line managers and teams focussed on planning, delivery, maintenance and operations, account for the all asset life cycle stages. The team numbers were based on consultation with our peers and in accordance with the current and medium term workload around the dairy industry growth and irrigation schemes.	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.	For our contractors we hold a comprehensive database for all staff. We identify the training requirements by considering the planned work programme and the competencies that the work to be carried out will require. Enduring competency requirements are linked to our AMPs will be a function of our Alliance Agreement with NETcon. We have bi-annual development reviews where managers and staff are given the opportunity to discuss and plan training and development for the immediate future	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. (eg, 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?	3	1. AEL Asset Management Policy chapters 3 and 4 2. Competency Matrix Training Records 3. BPM for AEL HR processes 4. NETcon Alliance Agreement 5. The AEL Safety Management System (SMS) audit reports.	Every position on our network department structure has newly created or revised position description. Many of these positions are newly appointed through a rigorous process where skills and experience are matched to the requirements of the various roles. All candidates are presented with the same technical and soft skill questions and are required to provide real examples from their work history to substantiate or demonstrate their skills. An evaluation matrix is filled out where scores are awarded for all competency requirements as required in the position description. An offer is made to the candidate with the highest score, provided the minimum threshold score is met.	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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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. AMP 3. NETcon Alliance Agreement and meetings 4. Senior management job descriptions and meetings.	Our AMP is made available to all staff on our internet and hard copies are distributed to the asset management and engineering teams. We meet with our contractors each month to discuss the progression of the works programme. We hold regular shareholder meetings where our asset management programme can be discussed. Our stakeholder engagement, for consumers tends to be ad hoc. We will need to improve our communications to better our score.	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?	3	1.Asset Management Framework 2. Asset Management Policy, Strategy and lifecycle strategies..	We have completed the mapping or our processes under our BPM project. Copies of all BPMs are available to staff on our intranet. . We are continuing to new BPMs to align with our new EAM system.	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. (eg, 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?	3	1. Asset attributes identified and documented in GIS and EAM. 2..Proposal for an asset information audit project. 3. Deloittes strategic IT review. 4. Business cases for relevant projects.	Business cases have been prepared and approved for our EAM system as well as our GIS. These documents broadly detail the system requirements. However, after implementation programs to better configure and utilise more functionality will be developed to better support the AMS and asset strategies.	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?	2	1. Restructuring has added more staff to GIS team. 2. New GIS BPMs for creating assets and loading job pack data. 3. Job pack process ensures data capture and verification. 4. Implementation of drawing management system.	Data verification, ratification, and cleansing are done continuously and on an ad hoc case-by-case basis. The implementation of our EAM and new GIS requires the verification of all existing data which will be done as a standalone project in 2018/19.	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 (eg, 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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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 ICT Manager 2. Review of the ICT system by Deloittes 3. Business Process Mapping development in new EAM system. 4. Board meetings and minutes.	The process of justifying the procurement and evaluation of an EAM system was based on the recommendation, and conducted in association with Deloitte after a review of our ICT systems some years ago. The evaluation process included site visits to our peers who had already implemented systems. During these visits functionality as defined and specified by us were demonstrated by the various distribution businesses. A function of the newly created ICT Manager role is to develop the ICT systems around our AMP	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?	**3**	1. Risk Management Policy and risk matrices as in Appendix A.3 2. Risk management processes identified in Policy. 3. Risk Committee includes directors and meets monthly. 4. Training sessions for all relevant network staff.	We have developed a Risk Management Policy and are in the process of identifying asset related risk across the asset lifecycle. We are in the process of implementing a risk management framework.	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 (eg, 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?	**2**	1. Use external experts to do asbestos in buildings review. 2. Health & Safety Management System, section 3. pp. 30,38 3. Competency Matrix 4. Hazard and Condition Review, Training Needs Analysis with GM-Risk and Safety 5. Senior management job descriptions.	We have early drafts for resourcing, competency and training requirements in place and have plans to progress the drafts.	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?	**2**	1. Health and Safety Management System, pp.10,11 2. Senior Management completes 'ComplyWith' questionnaire quarterly. 3. Training and Compliance Manager role description 4. Public Safety Management System, p. 19 5. We have a GM-Commercial & Regulatory to assist with regulatory matters.	We have compiled a compliance register that lists all of our compliance obligations. These are reviewed on a quarterly, six monthly and annual basis as is most appropriate and we report by exception to our board every quarter. The register is used as part of the overarching risk management plan that is linked to our asset management practices. We have yet to fully document our risk and control measures.	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 (eg, 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	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?	3	1. AMP detailing workplans and projects 2. Load growth Data 3. Engineering design reports 4. Alliance Agreement held with NETcon. 5. NETcon maintenance schedule 6. We have maintenance/construction standards and drawings for use by contractors.	We have document control measures in place for all of our asset drawings. And we have established BPMs for the building of new assets. We are in the process of implementing lifecycle and fleet strategies in our new EAM system. We are now reviewing our initial BPMs as part of our implementation of the new EAM.	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 (eg, 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. We have defined maintenance & inspection plans and schedules. 2. Well defined outage management process. 3. NETcon Alliance Agreement 4. Fortnightly meetings between NETcon and the AEL Asset Manager 5. Spread sheets outlining the basic maintenance status 6. Asset commissioning check sheet.	As part of implementing OneEnergy (EAM), we are revising maintenance processes and setting up maintenance schedules based on asset condition, age and reliability data. As we capture more data, these processes will improve and result in increased benefits. As part of the the new EAM system KPIs will be defined and measured.	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 (eg, 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. AMP, chapter 6 and 8 2. Network Policy: Public Safety Management System, p. 21 3. Asset Management lifecycle strategies. 4. Fortnightly meetings between NETcon and the AEL Asset Manager. 5. NETcon spread sheets outlining basic maintenance status.	Condition assessments are predominately paper based records. There are some gaps in the historical information held. Part of the installation of a new EAM will be data cleansing and ratification. Once complete we would expect an increase in score. We are yet to formalise or determine measures to review our processes.	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. Defects register and action discussed at fortnightly contractors meeting. 3. AEL Emergency Preparedness Plan, chapter 2 & 3 4. Health & Safety Management System, p. 11 5. Participant Outage Plan, chapter 3.1 6. Position descriptions of Senior Management 7. Risk management policy.	Our Emergency Preparedness Plan supports us to respond to emergency situations in an appropriate and timely manner. The new EAM system that supports the centralisation of documentation will greatly assist us in improving our score in the future.	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.

Company Name	Alpine Energy Limited
AMP Planning Period	1 April 2018 – 31 March 2028
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))?	1	BPM EAM Scope for Tech 1 AMS	Our EAM has been designed around the review of our previous asset management systems and our present and future requirements. An audit procedure will be developed once the EAM implementation is completed and all relevant BPM revised.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, 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?	1	1. Health & Safety Management System, section 2, p. 16 2. AEL Emergency Preparedness Plan, chapter 2 3. Hazard and Incident Report form 4. NETcon Alliance Agreement 5. Fortnightly meetings between NETcon and AEL.	We have processes for routine and preventive inspection, maintenance and performance programmes. In addition we have a plant fault report database for the capturing and action of all plant related faults that are discovered. Our investigation processes fully document incidents of asset failures taking note of nonconformities to establish root cause.	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?	1	1. AMP appendix A.3 2. Staff hire; IT Manager and Network Manager, including position descriptions. 3. Acquisition of the Vault Health and Safety Data Base 4. Business Process Mapping for procurement, storage, installation of assets in EAM. 5. Risk management policy	Our Risk Management Policy as it relates to the network, focusses on risk levels, what is acceptable or not, and the associated costs. Justification of projects is based on the level of risk reduction to the company.	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?	2	1. AMP, section 7.5 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.	We support and encourage all technical staff, especially engineers to attend the annual EEA conference where new technologies and systems are marketed and displayed. Some vendors also present papers as part of the conference program. The assistance of Deloitte in the evaluation of EAM systems exposed us to all the recognised systems on the market. All staff has internet access and we are regularly informed by staff and the industry of new technologies, product/system developments and training courses.	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 (eg, 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.

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SCHEDULE 14A

Company Name: Alpine Energy
For Year Ended: 31 March 2018

Mandatory Explanatory Notes of Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018))

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is part of the audited disclosure information, and so is not subject to the assurance requirements specified in Section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a).

In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

To derive the capital expenditure in nominal dollar terms, the constant price forecasts were inflated by approximately 2% per annum, on a straight line basis, based on New Zealand Treasury forecasts. To derive the 10 year forecast, 2% was selected as a conservative inflationary rate. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 2% per year.

Commentary on difference between nominal and constant prise operational expenditure forecasts (Schedule 11b).

In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year, as disclosed in Schedule 11b.

To derive the operational expenditure in nominal terms, the constant price forecasts were inflated by approximately 2% per annum, on a straight line basis, based on New Zealand Treasury forecasts. To derive the 10 year forecast, 2% was selected as a conservative inflationary rate. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 2% per year. The real expenditure is reducing to reflect the expected efficiency gains per annum that will be found by improvements to our processes and practices. We expect to share realised benefits with consumers by reducing our operating expenditure, in real terms, over the next 10 years. Therefore the difference between nominal and constant operational expenditure forecasts is a reduction of 2% per year.

3. NETWORK RISK MANAGEMENT

This appendix outlines the risk management approach we employ for managing our network assets and activities. All risk management plans form part of our integrated Safety Management System (SMS), which is shown in Figure 8.10

With the implementation of an extensive Risk Management Policy we are reviewing and strengthening our comprehensive risk management register to provide risk management consistency across all facets of our company, and to support and standardise our risk assessment and mitigation management.

All our activities involve risk. We manage risks by anticipating, understanding, and deciding whether or not to modify the activity to mitigate the risk. The purpose of risk assessment is to provide empirical knowledge and analysis to make informed decisions on the treatment and method of resolution of particular risks.

We will accept risk in order to achieve or exceed our objectives, provided that the risks are understood and appropriate mitigation is in place to ensure the risk is within our bounds of acceptable risk.

We assess and treat risk as part of asset management. For confidence and consistency, we undertake our risk management activities in accordance with our Risk Management Policy. The Policy was approved by the Board of Directors, and the CEO, effective from 15 October 2015. Our Risk Management Policy is consistent with the international standard AS/NZS/ISO 31000:2009 Risk Management—Principles and Guidelines, and was peer reviewed by experts in risk management.

We aim to integrate high quality risk management activities with all critical processes so that we are able to recognise and respond to risk before events occur. Responsibility for managing risks rests with all staff and the Board of Directors, as described in Table 8.11 Risk management responsibilities and accountabilities. Accountability for risk management includes ensuring that the necessary controls to modify the risks and control assurance activities are in place and are effective at all times.

Table 8.10 Risk management responsibilities and accountabilities

Title	Responsibility
Board of Directors	The Board is responsible for approving of the Risk Management Policy, determining our risk criteria, ensuring the Policy can be implemented, monitoring 'very high' risks, the correct functioning of critical controls, and effective implementation of the Policy.
Chief Executive Officer (CEO)	The CEO is accountable to the Board for approving our risk management standards, and ensuring the standards are applied consistently to all planning and decision making.
Group Manager—Corporate Services	The GM—Corporate Services is accountable for: • developing and maintaining our risk management standards • providing technical risk management support, and associated tools and practices • reporting to the Audit and Risk Committee (excluding Health and Safety matters).
Executive Management Team (EMT)	The EMT is responsible for monitoring and reviewing our risk management activities and performance, including consistency with AS/NZS ISO 3300 and our guidelines and procedures.
Group Manager—Safety and Risk	The GM—Safety and Risk is accountable for: • developing and maintaining our Health and Safety risk management standards • providing technical risk management support, and associated tools and practices. • reporting to the Board Health and Safety Committee
Managers and team leaders	Managers and team leader are responsible for applying our standards to the assessment and treatment of risk in their business areas, and for monitoring the correct functioning and ongoing applicability of controls.
All personnel	All personnel are accountable for fulfilling their specific risk management functions.

Assurance of good governance will be achieved through the regular measurement, reporting, and communication of our risk management performance by ensuring that the resources, delegations, and organisational arrangements are in place. We are in the process of establishing an assurance programme to help us monitor our progress.

With our Risk Management Policy aligned to AS/NZS/ISO 31000:2009 Risk Management—Principles and Guidelines, the risk management process involves risk

- identification
- analysis
- evaluation
- treatment
- monitoring and review.

Our network is exposed to a range of internal and external influences that can have an impact on our business objectives. These influences provide a context for risk identification. The nature of electricity networks means that the network may be exposed to events that push the integrity of the components past design capability. The subsequent failures have to be reviewed to determine the impact on the network, consumer supply, and our ability to limit the disruption through risk mitigation.

The appropriate plan of action in response to an identified risk may include capital development, maintenance or operational enhancement, business planning or training, and contingency planning. Our maintenance programme includes routine inspections to ascertain asset condition and regulatory compliance. Our policies rank public safety and environmental impact as high priorities.

3.1. RISK IDENTIFICATION

Identification of network risk is an iterative process. While our process is well developed, new techniques for predictive condition support and proactive risk management are being developed based on long-life assets (for example, the recent release of the new EEA guide—Asset Health Indicators).

Consequences of risk on our network can be grouped into the following categories:

- reputation
- natural environment
- compliance
- financial
- asset utilisation
- reliability of supply
- security of supply

Environmental risks

We are committed to operating in a manner that is environmentally sustainable.

There are many events outside of our control that threaten to interrupt the operation of our distribution network (e.g. floods, high winds, lightning, snow, earthquake tsunami, fire, etc.). To counter the effects of such events on the environment and the public (e.g. chlorofluorocarbon gas emissions, oil spills, arc flash exposure, failure of line supports, etc.), we place great importance on the selection and installation of our network components.

External risk

Risk to the network can be introduced by the public through:

- inadequate control of trees adjacent to overhead lines
- operating plant or stockpiling material without adequate clearance from overhead lines
- lighting fires adjacent to overhead lines
- moving irrigators under overhead lines
- undermining pole foundations
- colliding with our assets (e.g. car versus pole)
- illegal access into authorised areas
- leaving electric fence wire or other conductive material where wind or birds may carry it up into overhead lines.

3.2. RISK ANALYSIS

Risk analysis is used to determine the most effective means of risk treatment. A number of dimensions must be satisfied to meet our objectives of managing our assets in a safe, reliable, and cost-effective manner.

We have undertaken a qualitative assessment of risk that we face to determine its ranking. Table 8.12 lists the qualitative measures of likelihood we use in our risk assessment.

Table 8.11 Measure of risk likelihood

Level	Descriptor	Description	Indicative return period
5	Certain	Will occur frequently	Once or more per annum
4	Likely	Will occur infrequently	Once in 1–4 years
3	Possible	Might occur	Once in 4–10 years
2	Unlikely	Will seldom occur	Once in 10–50 years
1	Rare	Theoretically possible but unlikely to occur	Once in 50–100 years or less

Table 8.12 Measure of risk consequence

Consequence level	Insignificant	Minor	Moderate	Severe	Extreme
Reputation	No interest outside Alpine Energy	Local papers, brief criticism, little controversy	Local and regional media, criticism not widespread, brief	Regional and national criticism for more than two days	Regional and national media criticism, highly adverse, sustained for a week or more
Natural environment	Little or no impact	Small scale contained event, short-term impact, managed internally	Event restricted to one locality, localised impact on habitat/ environment; some external support required	External support required to contain, notifiable, potential long-term impacts	Massive environmental contamination damage to endangered flora/ fauna
Compliance	No breach	Breach of legislation, code of practice, or industry standard; no applicable penalties	Financial penalty of up to $10,000	Prison term of less than two years and/ or financial penalty of up to $100,000	Prison term of more than two years and/ or financial penalty of over $100,000
Financial	Potential loss or cost of up to $20,000	Potential loss or cost of $20,001–$100,000	Potential loss or cost of $100,001–$1 million	Potential loss or cost of $1 million–$5 million	Potential loss or cost of > $5 million
Asset utilisation		Network asset (to the value of under $100,000) underutilised or stranded	Network asset (to the value of $100,000–$1 million) underutilised or stranded	Network assets (to the value of $1 million–$5 million) underutilised or stranded	Network assets (to the value of over $5 million) underutilised or stranded
Reliability of supply	Unplanned outages (Class C): <1 SAIDI min or <40 ICP interruptions per event	Unplanned outages (Class C): 1<&<3 SAIDI mins or 40<&<100 ICP interruptions per event	Unplanned outages (Class C): 3<&<33 SAIDI mins or 100<&<1000 ICP interruptions per event	Unplanned outages (Class C): 33<&<161 SAIDI mins or 1000<&<1500 ICP interruptions per event	Unplanned outages (Class C): >161 SAIDI mins or >1500 ICP interruptions per event
Security of supply	Non-compliance on loads below 0.2 MVA	Non-compliance on loads 1<>0.2 MVA or inability to supply new load within three months	Non-compliance on loads >1 MVA or inability to supply new load within 12 months	Non-compliance on loads >9 MVA or inability to supply new load within 24 months	Non-compliance. Causes negative growth or inability to supply new load within 48 months

Figure 8.9 combines the qualitative assessment of consequence and likelihood to provide a level of risk matrix.

Likelihood						
	Certain	Low	Medium	High	Very High	Very High
	Likely	Low	Medium	High	High	Very High
	Possible	Low	Medium	High	High	Very High
	Unlikely	Low	Low	Medium	Medium	High
	Rare	Low	Low	Low	Medium	High
		Insignificant	Minor	Moderate	Severe	Extreme
		Consequence				

Figure 8.1 Network risk matrix

Based on the risk score, specific response and reporting requirements are determined. The requirements are described in Table 8.13.

Risk analysis evaluates the factors that influence the consequences and likelihood of an event, as well as the effectiveness of existing controls and management strategies.

Quantitative analysis is used where specific performance measures are in place, e.g. oil sample testing of zone substation transformers. The testing provides a review of compounds in the oil sample to determine health and position on the age curve based on known operating history. The quantitative approach allows us to manage assets with the highest event consequence cost throughout expected service life.

Table 8.13 Response by risk level

Level of risk	Urgency for implementation of treatment	Authority for continued tolerance of risk	Reporting
Very high	Immediate corrective action to rectify or mitigate the impact of the identified risk to be implemented ASAP under GM—Network's supervision	CEO	Advise GM—Network immediately, and the GM to advise CEO immediately after receiving advice and to include in next reporting cycle. CEO to advise Risk and Audit Committee (Board) as appropriate and to include in next reporting cycle.
High	Action plan to be developed within [x] days of the identification to GM—Network (or such other period that is practical in the circumstances).	GM—Network	Advise GM—Network within 24 hours of identification, and the GM to advise CEO as soon as practicable after receiving advice and to include in next reporting cycle.
Medium	Action plan (if necessary) to be developed within [x][27] months of identification to the GM—Network (or such other period that is practical or necessary in the circumstances).	Managers	Advise GM—Network within five days of identification. If necessary, include in next reporting cycle.
Low	Treat in line with other priorities. Ongoing monitoring.	Manager	Advise Manager or, if appropriate, relevant committee or group (e.g. Planning Committee).

[27] Where [x] days or months, the number is determined by the GM—Network to suit the circumstance.

3.3. HIGH CONSEQUENCE LOW PROBABILITY RISKS

Our distribution network is built in a hierarchical structure with Transpower substations providing supply points for 33 kV subtransmission to zone substation assets. The zone substations have multiple feeders that connect the 11 kV distribution lines. Distribution lines traverse the region and support 11 kV assets and distribution transformers, which break down into the LV networks and more than 31,000 individual connection points.

Failure of a hierarchy asset at the Transpower connection level carries the serious consequence of potentially disrupting a large number of consumers. At our zone substations the failure of any equipment that would result in a substation outage would typically constitute a high consequence/low probability risk. Examples of these are transformers, circuit breakers, cables, etc. depending on the zone substation.

In order to mitigate against high consequence low probability events at five of our zone substations, we have procured standby diesel generation plant and a mobile substation as described below.

- A mobile generator set (AMG) made up of two 900 kVA generators able to base load at 500 kW each or 1 MW in total. The AMG can be used at 11 kV or 400 V to allow maintenance of distribution substations or provide small community back-up.
- A mobile substation (AMS) that steps 33 kV to 11 kV with a 9 MVA rating. We are preparing all of our single transformer zone substations so that the AMS can be installed in parallel to allow the release of the zone substation for maintenance.

Zone substation transformers

Table 8.14 details our high consequence / low probability risks as it relates the highest consequence risk category with both pre- and post-mitigation risk scores. A detailed risk analysis based on our policy has been completed for each of our zone substation to obtain the listed scores. For all cases except Geraldine, Bells Pond and Twizel, the contingency plans details the use of back-feed (i.e. supply from adjacent zone substations) as well as the deployment of our mobile substation to restore supply.

Since commissioning of our mobile substation in 2014, we have to date completed five projects at five zone substations, to enable us to connect our mobile substation, or our mobile diesel generation at these zone substations in the event of an emergency. The remaining zone substations are:

- Geraldine where the project to enable connection of our mobile substation is due for completion in 2018
- Bells Pond where we have started a project under our current capex workplan to install a second transformer. The project will be completed under the 2017/18 workplan.
- Twizel is included in the 2018/19 workplan to enable mobile substation connection.

Table 8.14 Zone substation transformer risk analysis

Zone substation	Risk Category	Current risk score	Risk category details
Pleasant Point	Reliability of supply	Low	Loss of supply to 1224 ICPs
Cooneys Road	Reputation & Environment	Medium*	Loss of supply to Oceania Dairy factory, 1 ICP. Factory unable to process milk and dairy farmers unable to get milk removed from their farms. Milk deposited on pastures or dumped.
Geraldine	Reliability of supply	Medium	Loss of supply to GLD township and surrounding rural areas 2496 ICPs
Bells Pond	Reliability of supply	Low	Loss of supply to Oceania Dairy factory and rural areas, 585 ICPs. Factory unable to process milk and dairy farmers unable to get milk removed from their farms. Milk deposited on pastures or dumped.
Albury	Reliability of supply	Medium	Loss of supply to 1017 ICPs
Fairlie	Reliability of supply	Medium	Loss of supply to 1014 ICPs
Tekapo	Reliability of supply	Medium	Loss of supply to 644 ICPs. Tekapo is a very busy tourist town and a loss of supply would also result in reputational damage not just to Alpine Energy but also NZ.
Twizel	Reliability of supply	High**	Loss of supply to 1396 ICPs. Twizel is a very busy tourist and business services town and a loss of supply would also result in reputational damage and economic loss.

* Even though mitigation has reduced the risk consequence from 'Severe' to 'Moderate', the resultant risk score based on the matrix is still 'Medium'.

** The resultant 'High' risk score after mitigation is due to the fact that the reliability of supply threshold set for 'Extreme' consequence is 161 SAIDI minutes. So even through mitigation results in an improvement, based on the policy the score remains 'High'.

Our other larger zone substations such as Timaru, Pareora, Rangitata, Temuka, Clandeboye #1, and Clandeboye #2 are all constructed with N-1 security (i.e. two transformers) and therefore the loss of one transformer would not affect the supply. The remainder of our zone substations are small and does not fall into the high consequence category for a loss of transformer or incomer circuit breaker.

Our maintenance procedures and schedules include regular inspections and oil sampling and testing. Major maintenance is done when a transformer is moved from one location to another and when a substation is equipped to connect our mobile substation.

Incoming supplies

The highest risk of outages is the reliability of the incoming supply. Typically, the incoming supply is provided by Transpower. In cases where the substations are supplied via a single feeder, necessary repairs result in outages. Overhead line incoming supplies are clearly visible and any repairs are normally done within hours rather than days and hence these do not result in severe or extreme risk consequences. To reduce the level of risk, detailed studies are undertaken to determine the costs and benefits of duplicate feeders or alternative generation options.

Where we have cable circuits for incoming supplies, there are duplicate circuits (i.e. N-1 security) at all zone substation except at Albury. However the incoming cable circuit is only 61 metres in length and laid within the substation fenced area as well as a section in an easement on private land and not readily accessible by the public. The likelihood of a failure is rare and due to the short length, finding and repairing a fault can be achieved within a day.

Switchboards

The loss of a switchboard will most likely be as a result of a fault in the busbar zone which will result in a loss of all outgoing feeders, which similar to the loss of a zone substation transformer, can result in a high consequence risk. Due to the nature of bus zones being totally enclosed and being indoors within a controlled access environment, the likelihood of bus zone faults are rare. For the zone substations where we have connection points for our mobile substation, the risk analysis is similar to the loss of a transformer as detailed in Table 8.14.

The risk assessment for remainder of our zone substations and major switching stations in the Timaru urban network, for the highest risk category, are detailed in Table 8.15. All new switchboards that were installed in the last seven years are arc flash rated boards and have been fitted with arc flash protection systems that significantly reduces the consequence of a bus zone fault since the fault is isolated from damaging other parts of the board. These systems are present at North Street, Grasmere Street, and the new Rangitata (transformer #2) substation switchboards.

Table 8.15 Switchboard risk analysis

Zone/switching substation	Risk Category	Current risk score	Risk category details
North Street	Reliability of supply	Medium	Loss of supply to 1195 and 826 ICPs for the two busbars respectively.
Grasmere Street	Reliability of supply	Medium	Loss of supply to 1404 and 1705 ICPs for the two busbars respectively.
Hunt Street	Reliability of supply	Medium	Loss of supply to 1952 and 1544 ICPs for the two busbars respectively.
Pareora	Reliability of supply	Low	Loss of supply to 389 and 838 ICPs for the two busbars respectively.
Temuka	Reliability of supply	Low	Loss of supply to 1292 and 1646 ICPs for the two busbars respectively.
Rangitata[28]	Reliability of supply	Low	Loss of supply to 241 and 195 ICPs for the two busbars respectively.
Clandeboye 1	Reliability of supply	Low	Loss of 1 ICP
Clandeboye 2	Reliability of supply	Low	Loss of 1 ICP
Studholme	Reliability of supply	Low	Loss of supply to 2296 and 885 ICPs for the two busbars respectively.

[28] This refers to the old switchboard for transformer #1

The risks at the Clandeboye substations are mitigated in that the site has a supply security level of N-1.

The two PAR 33 kV switchrooms, one for each half bus, have arc flash containment and ducting to the exterior. It has N-1 supply security with respect to the switchboards and are therefore rated as low risk.

The Rangitata, Studholme, Temuka, and Pareora 11 kV switchboards are fitted with bus zone protection will restrict a bus fault to a half bus outage. With tie points outside the substation, supply can be moved to one side of the switchboard while the faulted part is repaired.

The medium risk scores in Table 8.16 above are acceptable risk. These scores were achieved due to the number of consumers connected, and an outage in these instances is acceptable compared to the costs of reducing the score to low.

3.4. OTHER NETWORK ASSET RISKS

Ripple injection plants

Our ripple injection plants are important in the management of controllable load on our network. With the deployment of smart meters on our network, there is an alternative available for load control that is required for energy tariffs. However this does not affect emergency load control which presently can only be done through the use of the ripple injection plant. In order to mitigate the risk of a ripple injection plant failure, we conduct regular inspection and maintenance programs. In addition we also keep long lead time spares.

We have replaced all but one aged rotary ripple injection plant. The remaining one being located at our Tekapo substation will be replaced within the planning period.

Environmental

Snow and wind typically create high risks in the Mackenzie area of our network. Our design standards ensure appropriate materials that meet the extreme weather conditions are used. For example, the 11 kV switch room at the STU substation has been elevated to minimise flood risk.

Earthquakes pose a significant risk of network interruption and difficulty in supply restoration. The likelihood of an earthquake on our network has been deemed 'possible'. The likelihood of an Alpine Fault[29] event in the next 50 years is 30%[30]. This translates to a likelihood descriptor of 'Unlikely' in our risk matrix. Combined with a 'Reliability of supply' consequence level of 'Severe' to 'Extreme' would result in a risk score of 'High'.

Following an earthquake, checks will be required to ensure substations close to the fault are structurally sound. An earthquake on the Alpine Fault could cause some Twizel and Tekapo consumers to be without supply for several weeks. The Mackenzie substations are closest to the Alpine Fault and the area of the largest expected disruption.

In the past twelve months the Temuka substation site, which belongs to Transpower, has been flooded. The main reason is the inability of the existing swales on the roadside to deal with flood water. Vegetation and debris exacerbates this problem during flooding. We have sealed all ducts into our switchroom and the external portion of the cable trench, and have a submersible pump installed to remove water from the cable ducts. We also use sand bagging to minimise flooding of our switchroom.

ICT and Asset management systems

Our corporate and SCADA servers are duplicated and on hot standby in our North Street substation located 5 km from our Washdyke office site. This substation has additional space and facilities to provide a second base for control room operations in the event of a disaster damaging or destroying the Washdyke offices and depot.

3.5. RISK MANAGEMENT STRATEGIES

Where we identify unacceptable risk, we will mitigate unacceptable risks (in accordance with our Risk Management policy) to an acceptable level through well documented actions plans. We are still recognising that risks may remain, but as long the impact is known, this may be acceptable. The Risk Management policy defines delegated authority for accepting risks.

In mitigation we look to eliminate, isolate or minimise the risk from health and safety and network investment or expenditure perspective.

Justifying expenditure

In ensuring that we obtain the maximum benefit from every dollar we invest or spend, it is necessary for all investment and expenditure to be evaluated in a consistent manner. Our Risk Management policy and Risk Management framework allows us to compare the potential benefit to the company for investment and/or expenditure on all projects and maintenance activities.

This will enable us to:

- prioritise our investment/expenditure to reduce any risks to an acceptable level
- prioritise our investment/expenditure to make best use of our resources

Risk Management framework

Our Risk Management framework is intended to help us understand the risks and respond to these through appropriate mitigation.

All staff are able to and encouraged to identify any perceived risk which is then recorded in a risk register for analysis. The risk analysis is performed using the risk matrix to determine a risk score and documented. The risk score will then determine whether any mitigation and/or escalation are required. If mitigation is recommended then a post mitigation risk assessment is completed and documented to evaluate the post mitigation risk score.

Recognising that risk assessment is a subjective process, we encourage staff to seek support in performing initial risk assessments before registering a risk on the register. All registered perceived risks are evaluated by a selection of staff experienced in performing such assessments.

Prescribed mitigation will be actioned based on the risk score and level of escalation within the management structure. This could result in immediate action, a project scheduled in the workplan, or an adjustment to our maintenance regime.

[29] The Alpine Fault is a geological, right-lateral strike-slip fault that runs almost the entire length of the South Island. It forms a transform boundary between the Pacific and Australian Plates. More information can be found at http://en.wikipedia.org/wiki/Alpine_Fault

[30] According to the GNS Science website.

Staff development

As mentioned before a risk assessment is a subjective exercise. We acknowledge the fact that our staff require training in and exposure to the risk assessment process. In this regard we include training as part of the development path of all staff related to or involved in asset management.

3.6. NETWORK RESILIENCE

We are in general well positioned for high consequence low probability events. All new substation buildings are designed and constructed to a building importance level 4. Some of our existing large and important substation buildings have been strengthened for seismic events.

With less than 10% of our subtransmission and distribution network underground and therefore more susceptible to earthquake damage than overhead infrastructure, our ability to respond to infrastructure damage as a result of an earthquake is good.

We have recently commissioned a study of the condition, structural strength and seismic resilience of all our two pole substations. The results for all the concrete pole substations were good. We will be replacing five hardwood pole substations in Twizel in the next financial year.

Our ICT and SCADA systems are duplicated off site and will allow us to continue operations in the event of us being unable to access our current offices and site.

4. SAFETY MANAGEMENT SYSTEM

This appendix outlines the safety management approach we employ for managing our network assets and activities.

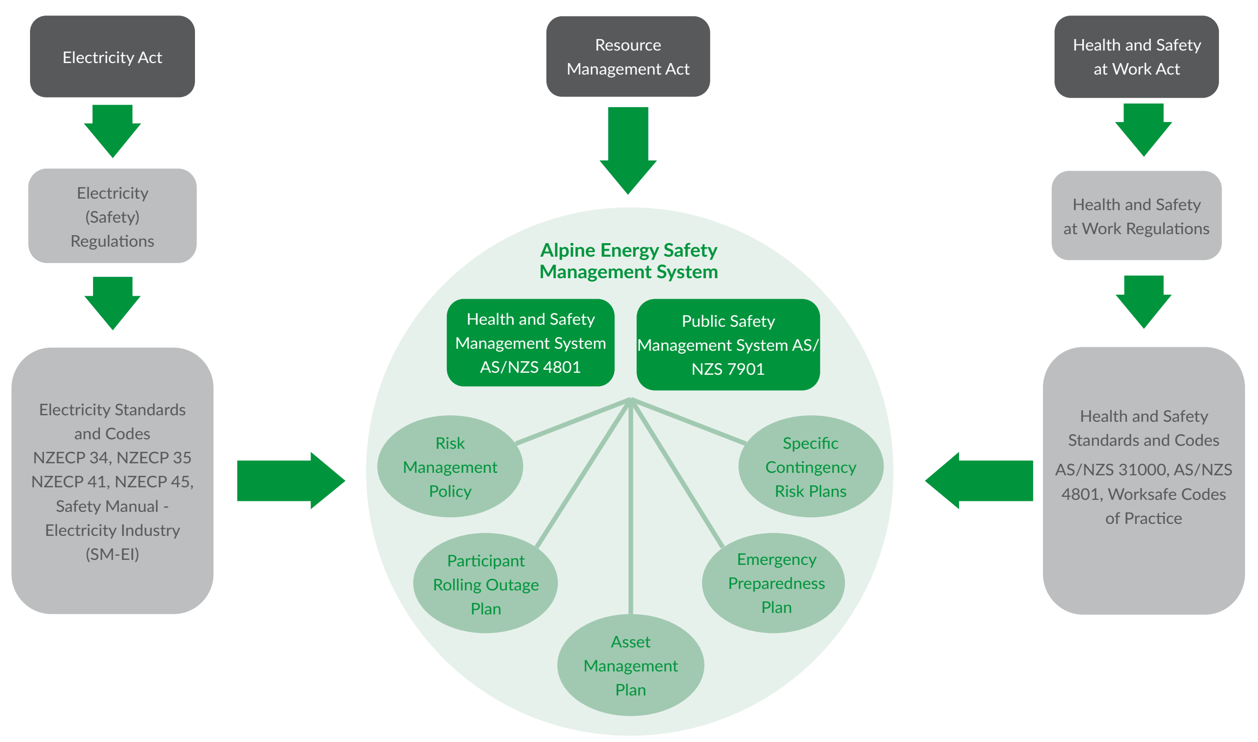


Figure 8.2 Safety Management System Framework

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

Our Public Safety Management System is subject to annual external audit to ensure compliance with the requirements of:

- NZS7901:2014 Electricity and Gas Industries—Safety Management Systems for Public Safety
- AS/NZS 4801:2001 Occupational Health and Safety Management Systems.

Our integrated Safety Management System also feeds into our:

- Asset Management Plan
- Emergency Preparedness Plan
- Participant Rolling Outage Plan
- Civil Defence Emergency Management
- Various specific contingency plans.

4.1. PUBLIC SAFETY MANAGEMENT SYSTEM

The Electricity (Safety) Regulations 2010 require all electricity distribution companies to produce an audited Public Safety Management System. The purpose is to prevent serious harm to members of the public or significant damage to public property from network assets and/or asset operation. Risk management activities referred to in this AMP are consistent with the requirements of the Public Safety Management System.

There is a statutory requirement to be audited to NZS 7901:2014 Electricity and Gas Industries—Safety Management Systems for Public Safety by an accredited audit body. The audits commenced in April 2012 and are carried out annually.

For further information, please refer to our Public Safety Management document which is available on request.

Public education

We reduce a number of external risks through public education. By placing regular safety messages in the media, we communicate to the public the consequences of their actions in relation to electricity and electrical assets. Communication through media helps us to create awareness in the community regarding potential hazards, and reminds the public to contact us when a hazard is perceived.
Figure 8.3 provides an example of our communication through print media.

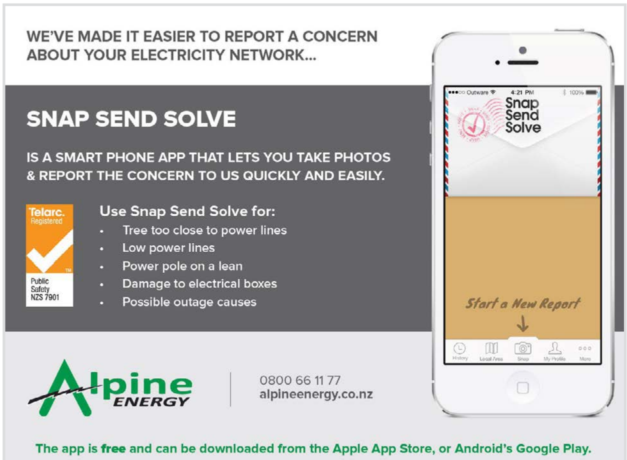
We also undertake joint public safety initiatives with South Island distribution companies.

For further details, please refer to our Public Safety Awareness and Education Policy which is available on request.

Figure 8.3 Media print example

We also participate in the Snap Send Solve app initiative. Members of the public can download the app onto their phone. They can then submit a report of any concerns regarding our assets using the app.

We are a member of beforeUdig. beforeUdig is an online service which enables anyone undertaking excavation works to obtain information on the location of our underground cables in and around any proposed dig site; helping to protect themselves and valuable assets during these works. In addition to the beforeUdig service, we locate and mark our underground services in request free of charge.



Security of ground mounted assets

Our ground mounted assets are protected from public intrusion by the standard practice of locking the external body equipment and by sometimes placing the assets in secure compounds.

For distribution boxes and link boxes we are implementing tamper-proof uniquely keyed fasteners to replace socket headed cap screws.

We are in the process of a major overhaul of our current lock hardware to a single unique hierarchical keyed lock system.

4.2. HEALTH AND SAFETY MANAGEMENT SYSTEM

The Health and Safety at Work Act 2015 requires all businesses to have an occupational health and safety management system in place. The purpose of the system is to prevent serious harm to workers, and the general public or significant damage to property arising out of our work activities.

For further details, please refer to our Health and Safety Management System document which is available on request.

4.3. EMERGENCY RESPONSE AND CONTINGENCY PLANNING

We recognise that the local economy depends on a secure and reliable supply of electricity, and that a catastrophic event such as an earthquake, landslide, tsunami, flood, wind and snow storms, and terminal failure of key assets can have significant impact on both the network and the local economy.

We have developed emergency response plans for dealing with widespread abnormal situations created by either asset failure or catastrophic natural events. All emergency response plans are regularly reviewed to ensure that unique risks arising from emergency response have been identified.

Mutual Assistance Agreements have been signed with peer electricity distribution networks. These agreements were successfully implemented during the Canterbury earthquakes in September 2010 and February 2011, wind storms and snow events in 2013, and the Kaikoura Earthquake in 2016

For further details, please refer to our Emergency Preparedness Plan. the Canterbury earthquakes in September 2010 and February 2011, wind storms and snow events in 2013, and the Kaikoura Earthquake in 2016

For further details, please refer to our Emergency Preparedness Plan which is available on request.

Business continuity planning

Regular electronic backups of mission critical records for retailer billing and consumer identification are carried out. The backup copies are securely stored offsite by our web host.

All ICT servers are virtually hosted across the North Street substation and Washdyke data centres. All systems can be run from either data centre in the case of loss of an entire site. Data backups are also physically held at each location.

SCADA is also duplicated at North Street including a set of paper copies of switching plans.

Emergency Preparedness Plan

Our Emergency Preparedness Plan complies with the requirements of NZS 7901:2014 and AS/NZS 4801:2001 and is regularly reviewed after each critical event, and on an annual basis.

The plan is distributed to our staff as part of our Health and Safety Management System, instructing them of the procedures to follow for emergency events, including:

- Civil Defence Emergencies
- major accidents
- fire and evacuation of site
- earthquake
- extreme climate events
- threats and conflict situations
- hazardous or toxic substances (oil spillage or SF_6 release)
- pandemic

Emergency communications

Our emphasis on appropriate emergency communication ensures information is provided to stakeholders and the public in a proactive manner. Our communication responsibilities are:

- Chief Executive Officer: media, stakeholders, EDBs, and Transpower
- Group Manager— Corporate Services: general public
- Group Manager–Safety and Risk: Police, Civil Defence, local councils and other local authorities, and large customers.

Responsibilities for communications are detailed in Section 4.2 of the Participant Rolling Outage Plan.

Telephone Video Data and network status report

The public can keep up-to-date on the location of outages and resolution timeframes by logging on to our website and follow the tabs referring to planned and unplanned outages. The public can also phone us for information and listen to the radio.

4.4. PARTICIPANT ROLLING OUTAGE PLAN

The Electricity Industry Participation Code 2010 Part 9 requires all specified EDBs to prepare and publish a Participant Rolling Outage Plan (PROP) for audit and approval by Transpower's System Operator.

The Plan is required to conform with the requirements set out in the System Operator Rolling Outage Plan (latest version 19 June 2016), and details how electricity distributors will assist the System Operator in managing either a total outage or rolling outages of up to 25% of normal load if there is a national or regional electricity shortage.

Our most current Participant Rolling Outage Plan was approved by the System Operator in September 2017. A copy of the current Plan can be found on our website (*Participant Rolling Outage Plan*).

4.5. SPECIFIC CONTINGENCY PLANS

Specific contingency plans for the restoration of supply to essential services and to individual major industrial and commercial consumers exist to complement and supplement the Participant Rolling Outage Plan. For example, if we lost both 110 kV TIM–TMK circuits that supply our Temuka zone substation, we have a specific plan developed jointly with Transpower to ensure electrical supply continuity to the Fonterra Clandeboye dairy factory.

4.6. CIVIL DEFENCE EMERGENCY MANAGEMENT

In the event of a Civil Defence Emergency, nominated staff members are sent to the local district council's Civil Defence Emergency Operations Centre. A dedicated radio telephone link is installed in the Timaru District Council's Emergency Operations Centre for direct communication with our control centre.

The Canterbury Lifelines Utilities Group[31] promotes resilience to risks, and develops contingency measures for Civil Defence Emergencies arising from natural disasters.

As a lifeline utility, we participate in the development of both regional and local Civil Defence Emergency Management plans, and provide technical advice to local authorities and other lifeline utilities as requested.

We participate fully in Civil Defence's regional exercises such as 'Pandora', 'Olaf', 'Ripahapa' and more recently 'Tongaroa' (a Tsunami simulation). Lessons learnt from these exercises are used to enhance our current emergency response planning. Delegates from board and executive management level have also attended the recent workshop where the South Island regional preparedness for a magnitude 8 earthquake in the Alpine Fault line was discussed.

[31] We were a founding member of the South Canterbury Lifelines Group, which amalgamated with the Canterbury Lifelines Utilities Group.

5. DEMAND FORECASTS

This appendix sets out the 10 year demand forecasts for Transpower's GXPs and our Zone substations.

5.1. DEMAND FORECAST FOR THE ALBURY REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	(MW)										
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Albury GXP	20	-	11.30	4.51	4.57	4.63	4.69	4.75	4.81	4.87	4.93	4.99	5.05	5.11
Albury zone substation	7.50	-	7.83	4.74	4.80	4.87	4.93	5.00	5.07	5.14	5.21	5.28	5.35	5.42
Fairlie zone substation	6.25	-	5.24	2.67	2.71	2.74	2.78	2.82	2.85	2.89	2.93	2.97	3.01	3.05

5.2. DEMAND FORECAST FOR THE BELLS POND REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	(MW)										
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Bell Pond GXP	60	20	34.29	13.68	14.89	16.09	17.29	18.50	19.70	20.90	22.10	23.31	24.51	25.71
Bell Pond zone substation	60	20	18.01	13.04	13.56	14.10	14.66	15.25	15.86	16.49	17.15	17.84	18.55	19.30
Cooneys road zone substation	15	-	22.4	3.45	3.45	3.45	3.45	3.45	3.45	3.45	3.45	3.45	3.45	3.45

5.3. DEMAND FORECAST FOR THE STUDHOLME (WAIMATE) REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	(MW)										
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Studholme GXP	20	10	25.20	16.44	21.49	21.77	22.04	22.32	22.59	22.87	23.15	23.42	23.70	23.97

5.4. DEMAND FORECAST FOR THE TEKAPO REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	(MW)										
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Tekapo GXP	10	-	10.50	6.00	8.55	9.58	10.22	10.35	10.51	10.65	10.77	10.89	11.01	11.13
Tekapo zone substation	6.25	-	4.04	4.60	6.72	7.82	8.56	8.82	9.11	9.38	9.65	9.92	10.20	10.49
HaldonLily Bank zone substation	1	-	2.55	0.45	0.46	0.47	0.49	0.50	0.51	0.53	0.54	0.56	0.57	0.59
Balmoral zone substation	0.60	-	0.38	0.36	0.63	0.70	0.98	1.02	1.09	1.14	1.17	1.20	1.24	1.27

5.5. DEMAND FORECAST FOR THE TEMUKA REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	(MW)										
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Temuka GXP	108.00	54	137.20	62.07	71.35	77.78	81.52	83.20	84.87	86.54	88.21	89.88	91.55	93.22
Temuka zone substation	50	25	20.38	12.84	13.23	13.64	14.06	14.50	14.94	15.40	15.88	16.37	16.87	17.39
Geraldine zone substation	9.00	-	14.29	6.84	7.05	7.27	7.49	7.72	7.96	8.21	8.46	8.72	8.99	9.27
Rangitata 1 zone substation	15	-	10.00	5.35	5.52	5.68	5.86	6.04	6.23	6.42	6.62	6.82	7.03	7.25
Rangitata 2 zone substation	15	-	7.20	4.02	4.14	4.27	4.40	4.53	4.67	4.82	4.97	5.12	5.28	5.44
Clandeboye 1 zone substation	40	20	46.86	15.84	19.64	20.84	20.84	20.84	20.84	20.84	20.84	20.84	20.84	20.84
Clandeboye 2 zone substation	50	25	55.84	15.16	18.96	22.52	24.60	24.60	24.60	24.60	24.60	24.60	24.60	24.60

5.6. DEMAND FORECAST FOR THE TIMARU REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	(MW)										
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Timaru GXP	141	94	96.60	66.38	71.85	72.21	72.58	72.95	73.32	73.69	74.05	74.42	74.79	75.16
Timaru zone substation	141	94	96.60	66.65	72.13	72.54	72.95	73.37	73.79	74.21	74.64	75.06	75.49	75.92
Pleasant Point zone substation	6.25	-	14.63	4.90	4.93	4.95	4.98	5.01	5.04	5.07	5.10	5.13	5.16	5.19
Pareora zone substation	30	15	15.35	8.87	13.12	13.19	13.27	13.35	13.42	13.50	13.58	13.65	13.73	13.81
Grasmere zone substation	31.29	23.46	-	27.12	28.18	28.34	28.50	28.67	28.83	28.99	29.16	29.33	29.49	29.66
North Street zone substation	30.89	15.44	-	13.28	13.36	13.43	13.51	13.59	13.66	13.74	13.82	13.90	13.98	14.06
Hunt Street zone substation	22.46	16.85	-	9.78	10.73	10.79	10.85	10.92	10.98	11.04	11.11	11.17	11.23	11.30

5.7. DEMAND FORECAST FOR THE TWIZEL REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	(MW)										
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Twizel GXP*	20	-	20	3.49	3.62	3.76	3.90	4.05	4.21	4.37	4.53	4.71	4.89	5.07
Twizel Village zone substation	6.25	-	6.86	3.49	3.62	3.76	3.90	4.05	4.21	4.37	4.53	4.71	4.89	5.07

6. REGION SCHEMATIC DIAGRAMS

This appendix contains the schematic Single Line Diagrams (SLDs) for each region.

Also refer to the overall SLD in Figure 3.2.

6.1. ALBURY REGION NETWORK CONFIGURATION

The Albury GXP is fed off the TIM–TKA 110 kV line and has a single 110/11 kV transformer connected to an 11 kV switchboard. The transformer was upgraded this financial year from 6 to 20 MVA. These are Transpower assets.

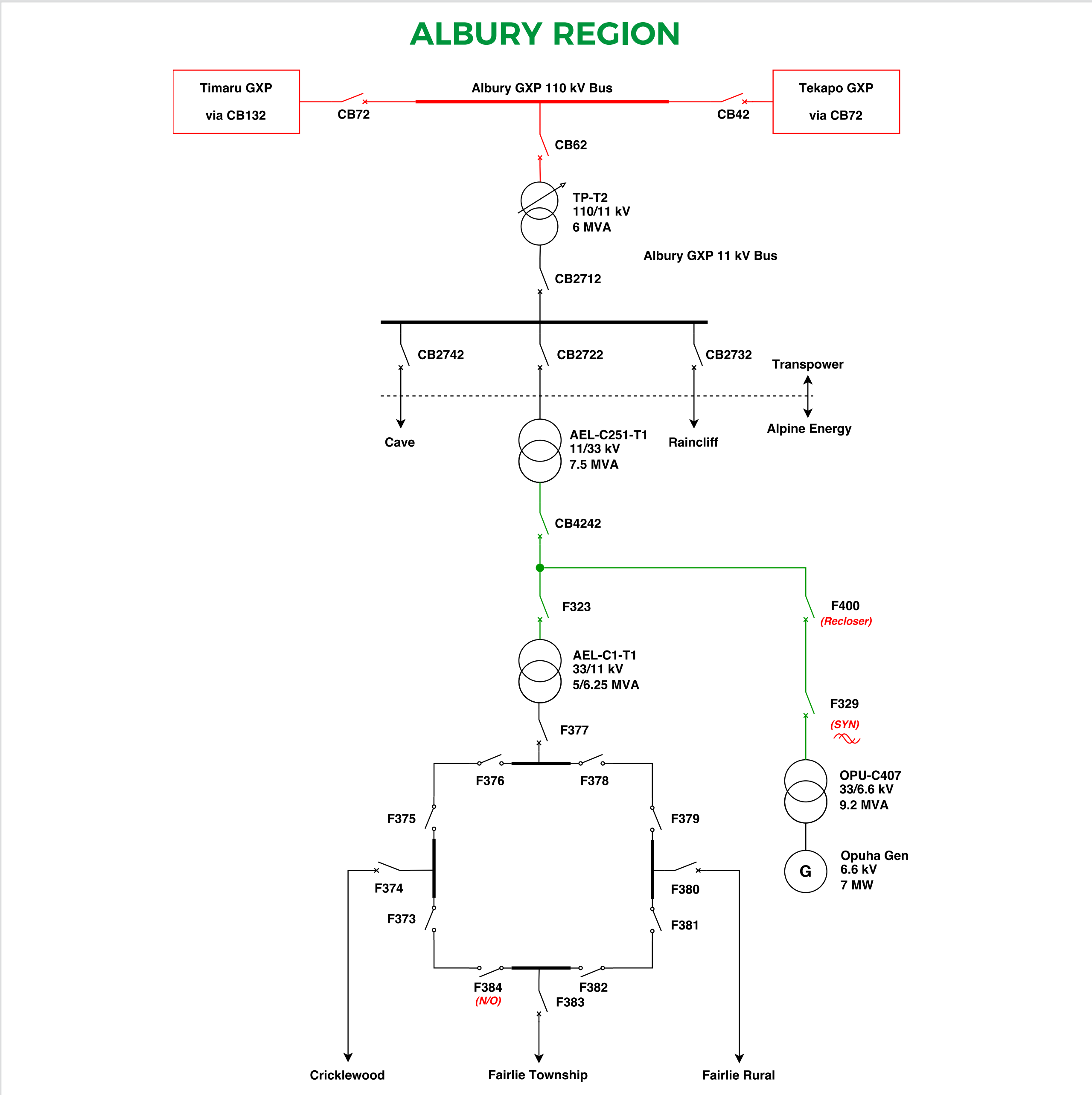
The Albury GXP has the ability to connect the Transpower mobile substation (110 kV to 11/22/33 kV) to allow maintenance at the Albury GXP and Albury zone substation.

We take supply from three feeder circuit breakers, two of which supply the 11 kV distributions feeders around Albury. The remainder circuit breaker feed into an 11/33 kV, 7.5 MVA stepup transformer for the supply to Fairlie, using a single 33 kV subtransmission feeder (overhead).

This same 33 kV feeder connects to the Opuha power station[32] (7 MW) beyond Fairlie.

There is an 11 kV ripple injection plant located at the Albury zone substation.

The Fairlie zone station has a 5/6.25 MVA transformer feeding three 11 kV distribution feeders for the Fairlie township and surround rural area. There are connections available for our mobile substation (33/11 kV, 9 MVA) and mobile generator (11 kV, 1.5 MVA).



[32] www.opuhawater.co.nz

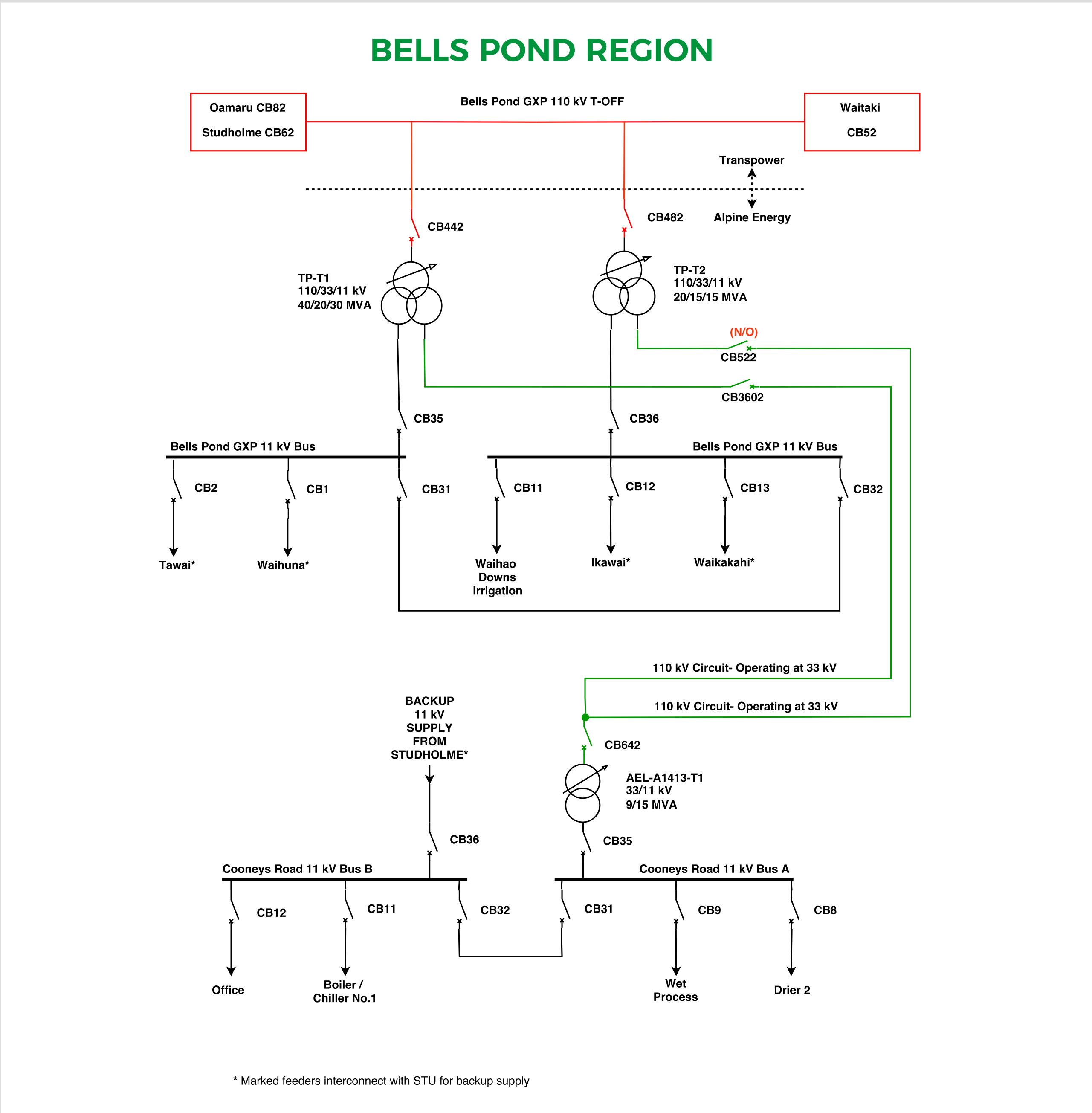
6.2. BELLS POND REGION NETWORK CONFIGURATION

Bells Pond GXP is a single tee off the STU–OAM–WTK2 110 kV Transpower transmission circuit. The GXP is essentially a 110 kV metering point with us owning and operating the 110/33/11 kV zone substation. The Bells Pond zone substation has dual 110/33/11 kV, 20/15/15 MVA and 40/20/30 MVA transformers feeding into two 11 kV switchboards. There are 5, 11 kV distribution feeders supplying the area around Bells Pond, with one dedicated to the Waihao Downs irrigation pump station.

There is an 11 kV ripple injection plant located at the Bells Pond zone substation.

A subtransmission line (dual circuit on a single pole line) constructed at 110 kV but operated at 33 kV supplies the Cooneys Road zone substation. This zone substation is located immediately adjacent to the ODL dairy factory. The 11 kV winding at BPD supplies the local rural feeders.

The Cooneys Road zone substation has a single 33/11 kV, 9/15 MVA transformer feeding a single 11 kV switchboard. Four 11 kV feeders are dedicated to ODL dairy factory, with one distribution feeder connected to an adjacent feeder from the Studholme zone substation.



6.3. STUDHOLME (WAIMATE) REGION NETWORK CONFIGURATION

The Studholme GXP is supplied from the 110 kV transmission from Timaru and from Waitaki. The 110 kV system is normally split on a manually operated switch (STU DS76) from 30 April until 1 October. This means the Studholme GXP is supplied from Waitaki. During the dairy season this switch is run closed and such providing an increased security of supply.

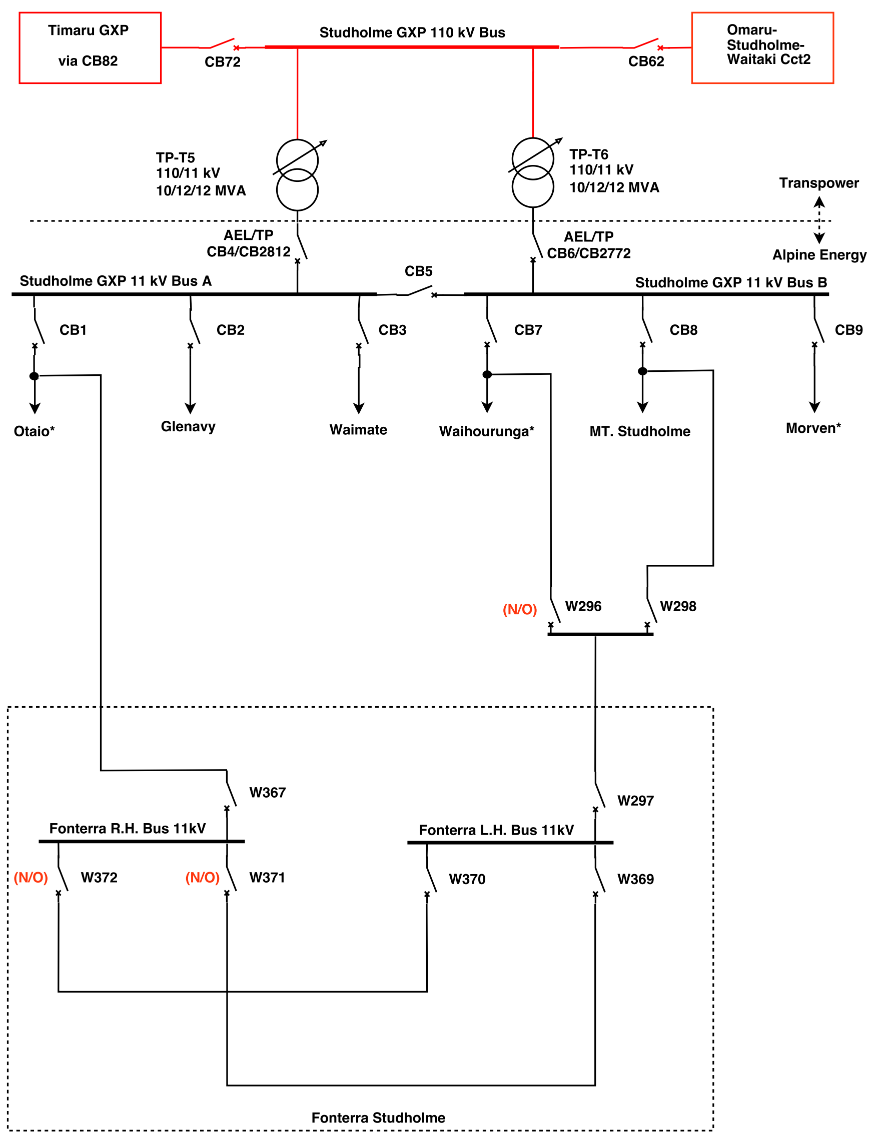
There are two 110/11 kV, 10/12/12 MVA transformer owned and operated by Transpower.

We take supply from Transpower at 11 kV. The 11 kV indoor switchgear has two incoming supplies, and six feeders supplying the nearby Fonterra Studholme dairy factory, the Waimate township, and the surrounding rural area.

The Fonterra Studholme dairy factory is supplied from three 11 kV distributions feeders (not dedicated) through a switching station comprising ring main units.

The ripple injection plant is connected to the Morven 11 kV distribution feeder.

STUDHOLME REGION



* Marked feeders interconnect with BPD and CNR for backup supply

6.4. TEKAPO REGION NETWORK CONFIGURATION

Transpower operates an 11 kV switchboard that connects to the Genesis Energy TKA power station. There are two step-up transformers; one 110/11 kV, 35 MVA transformer connected to the 110 kV TekapoAlburyTimaru transmission line and one 33/11 kV, 10 MVA transformer from which we take supply.

Genesis Energy can make its generator (28 MW) available to supply our Tekapo load when the Albury-Tekapo 110 kV circuit is out of service, and the Tekapo and Albury load when the Albury-Timaru 110 kV circuit is out of service.

Black start of the Tekapo generation and supplying the Tekapo load was successfully tested in November 2017.

The Tekapo GXP has the ability to connect the Transpower mobile substation (110 kV to 11/22/33 kV) to allow maintenance at the Tekapo GXP.

From the Tekapo GXP, we have a single 33 kV subtransmission circuit to our 33/11 kV Tekapo zone substation (5/6.25 MVA transformer).

From the Tekapo zone substation we have a 33 kV subtransmission line to Glentanner and Unwin Hut.

Unwin Hut is a small 33/11 kV zone substation which supplies the Mt Cook Village via a 1.5 MVA transformer and two 11 kV distribution feeders.

A 33 kV ripple plant is connected via a tap-off connection on the 33 kV subtransmission circuit at TEK zone substation.

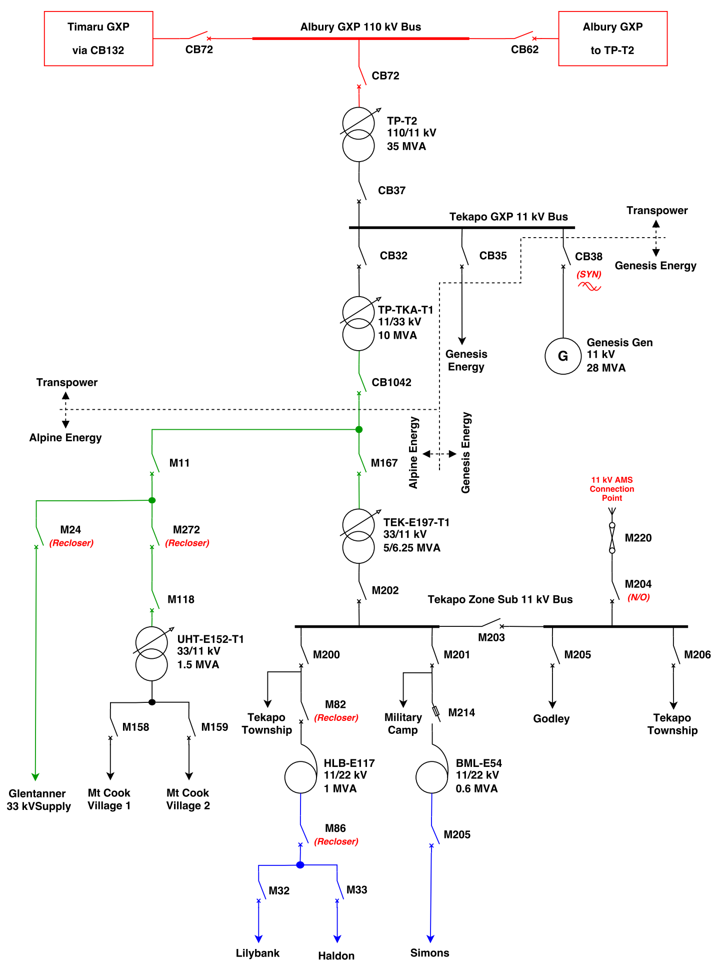
Connections for the mobile substation and standby/ emergency diesel generation are available at the Tekapo zone substation.

Tekapo zone substation supplies the Tekapo township and surrounding rural areas with four 11 kV feeders.

Balmoral (BML – 3 x 0.2 MVA single phase auto transformers) and Haldon–Lilybank (HLB – 1 MVA Auto transformer) are two zone substations fed off Tekapo which act as step-up transformers 22/11 kV into the remote Haldon, Lilybank, and Simon's Pass areas. The 22 kV distribution past HaldonLilybank zone substation is single phase.

There is a 33 kV Alpine mobile substation connection at Unwin Hut zone substation and an 11 kV Alpine Mobile Generator connection at Haldon-Lilybank.

TEKAPO REGION



6.5. TEMUKA REGION NETWORK CONFIGURATION

The Temuka GXP is supplied by two 110 kV transmission lines from the Transpower Timaru substation.

At the GXP, there are two 110/33 kV, 54 MVA power transformers which supply into a double switchboard. These transformers have a Special Protection Scheme (SPS) applied to mitigate against a total supply loss in the unlikely event of a transformer, or 110 kV line trip, while the load is more than 54 MVA. This will provide some security while the GXP constraint is being addressed.

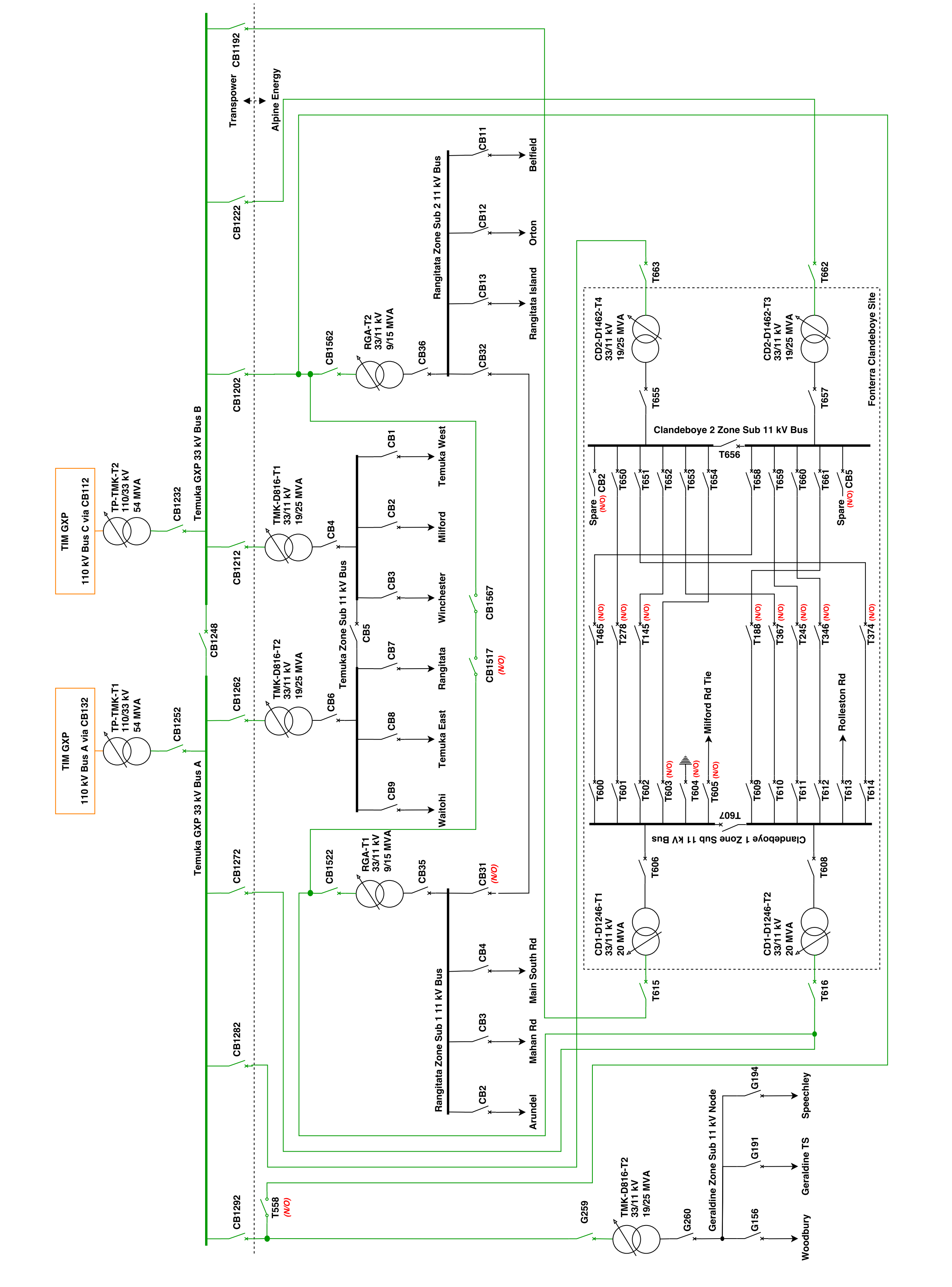
There are eight feeders from the 33 kV bus that supplies our network as follows:

- Four subtransmission feeders to Fonterra's Clandeboye dairy factory
    - Two double circuit lines and two cable circuits running through different routes for security.
    - They supply two 33/11 kV zone substations at the factory site
    - Clandeboye 1 and Clandeboye 2 zone substations consists of two 20 MVA and two 19/25 MVA transformers, respectively
    - Clandeboye 1 and Clandeboye 2 zone substations consists of eleven and nine feeders, respectively, interconnected together for security of supply
    - 33/11 kV Rangitata 1 zone[33] substation is supplied from a tap off one of the overhead lines (single 9/15 MVA transformer with three 11 kV distribution feeders).
- Two feeders supply our local 33/11 kV Temuka zone substation
    - Consists of two 19/25 MVA transformers with six 11 kV distribution feeders.
- One subtransmission feeder feeds the 33/11 kV Rangitata 2 zone substation
    - Consists of a single 9/15 MVA transformer with three 11 kV distribution feeders.
- One subtransmission feeder feeds the 33/11 kV Geraldine zone substation
    - Consists of a single 19/25 MVA transformer with three 11 kV distribution feeders.

A 33 kV ripple injection plant is connected to the 33 kV subtransmission feeders that supply our Temuka zone substation.

[33] Rangitata zone substation 11 kV bus coupler is operated normally open; hence the sub is treated as two separate substations, Rangitata 1 and 2.

TEMUKA REGION



6.6. TIMARU REGION NETWORK CONFIGURATION

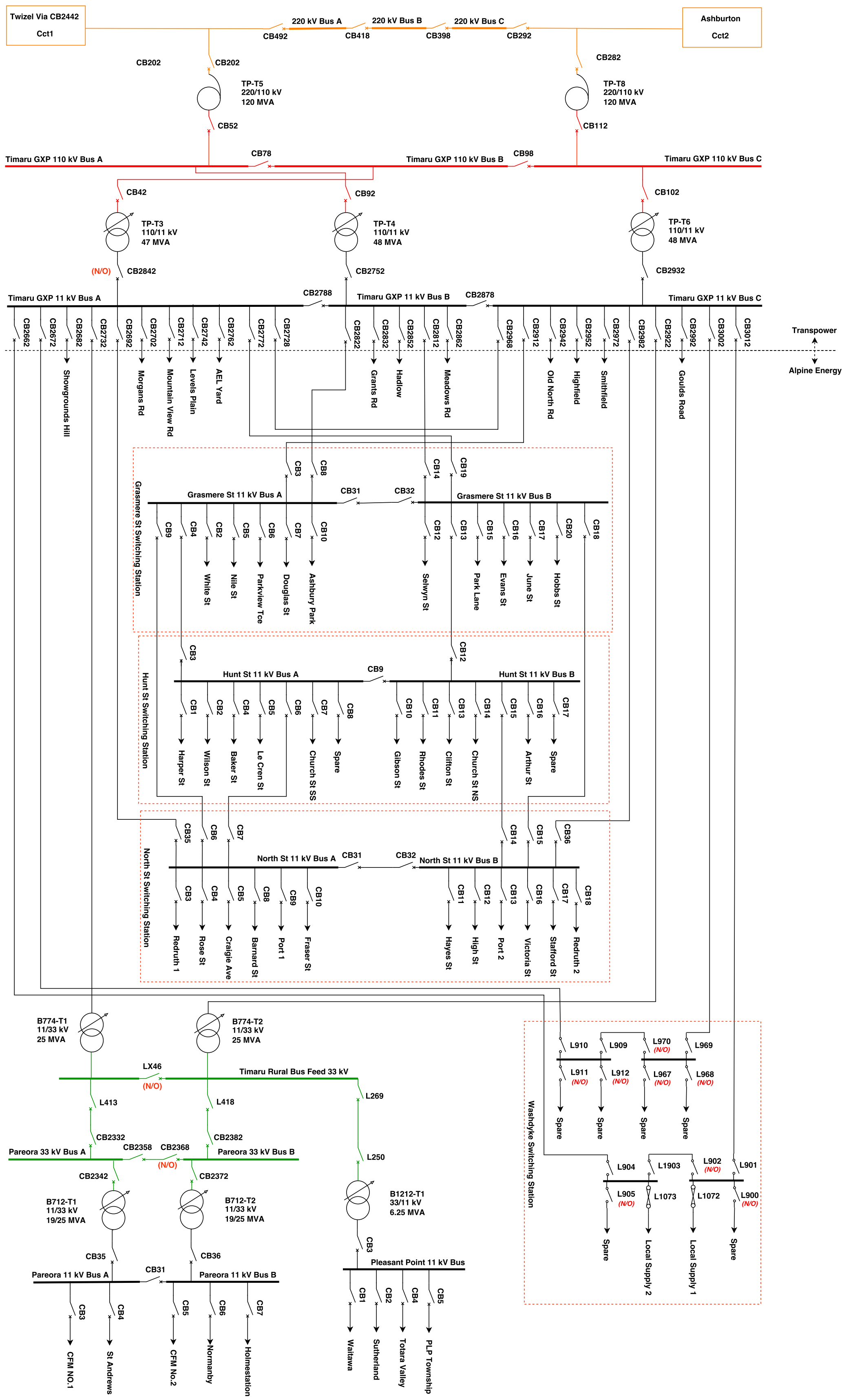
The Timaru GXP is our largest supply point connecting two 220/110 kV interconnectors to provide a 110 kV bus, which acts as a transmission hub for Albury, Tekapo, Temuka, and Bells Pond/Studholme. The 110 kV is stepped down through three transformer banks to supply the Timaru GXP 11 kV switchboard (owned by Transpower). The TIM 110/11 kV 47 MVA transformers are operated with two in service and one on hot standby.

The ripple injection plant is connected to the 11 kV switchboard.

There are 24 feeders from the 11 kV switchboard which are split across three buses as follows:

- Twelve of the feeders supply the western residential areas, the northern residential and industrial areas of Washdyke, and the meat-works at Smithfield.
- Two 11 kV feeders connect to two 11/33 kV step-up transformers at Timaru, supplying one 33 kV subtransmission feeder to Pleasant Point zone substation and two subtransmission feeders to the Pareora zone substation.
    - Pareora zone substation has five 11 kV distribution feeders supplying a meat processing plant and rural load at the south of Timaru.
    - Pleasant Point zone substation has four 11 kV distribution feeders supplying Pleasant Point township and outlying rural.
- There are four 11 kV subtransmission feeders to Grasmere switching station, which then split into a double circuit ring configuration to Hunt Street and North Street switch stations.
    - Grasmere switching station has ten 11 kV distribution feeders.
    - Two subtransmission feeders to Hunt Street switching station and North Street switching station respectively.
- The Hunt Street switching station has ten 11 kV distribution feeders.
    - Two subtransmission feeders to North Street switching station.
- Two 11 kV subtransmission feeders connect directly to North Street switching station (cables rated at 33 kV).
    - The North Street switching station has twelve 11 kV distribution feeders. Whilst North Street is presently a switching station, there is space to fit 33/11 kV transformers when load requires the substation to be converted to a zone substation.
- There are four 11 kV subtransmission feeders supplying the Washdyke switching station (cables rated at 33 kV). There is space to convert Washdyke switching station to a 33/11 kV zone station in the future.
    - Washdyke switching station (four ring main units), has four 11 kV distribution feeders supplying the Washdyke/Seadown commercial and rural area north of Timaru.

TIMARU REGION



6.7. TWIZEL REGION NETWORK CONFIGURATION

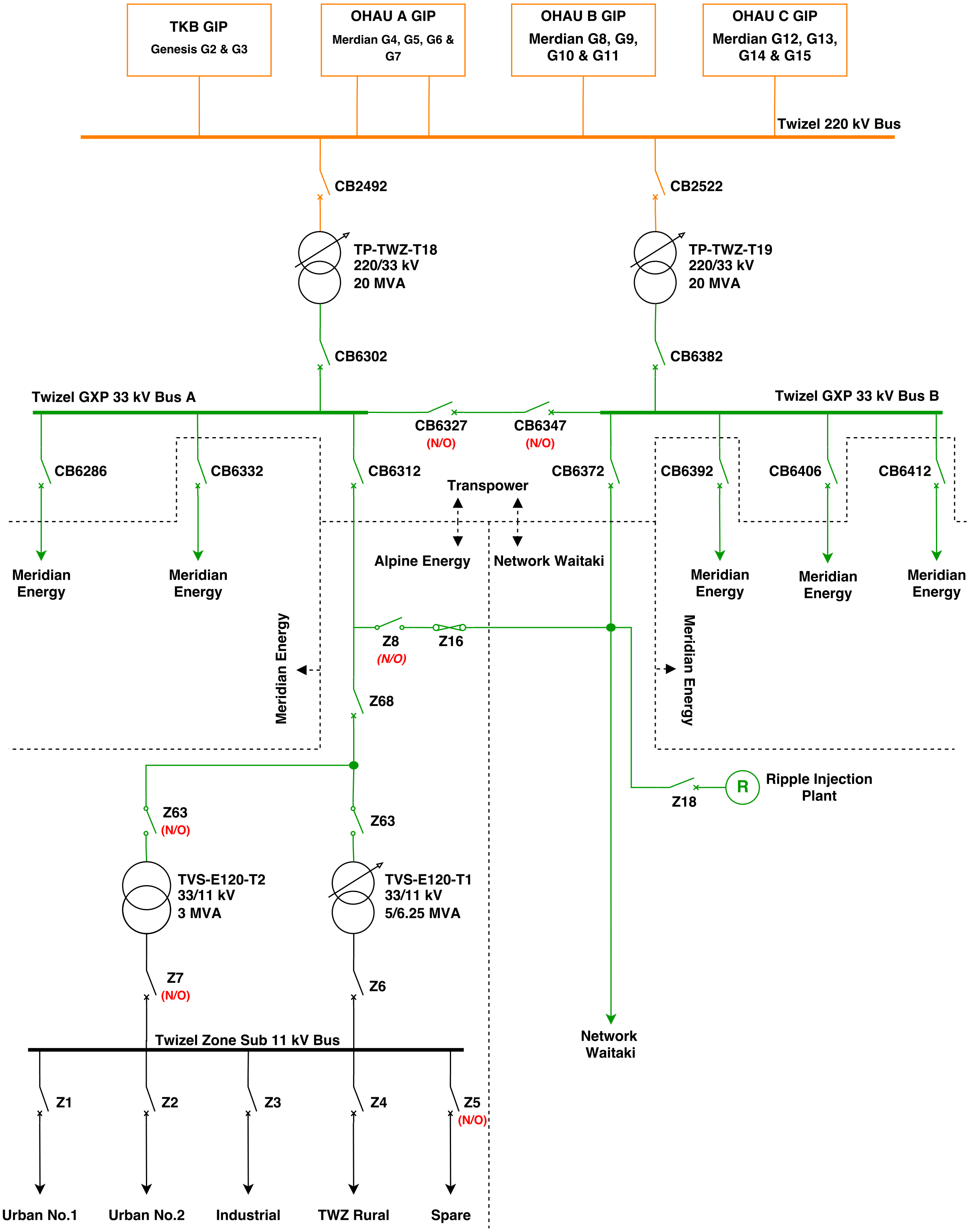
The Twizel GXP is supplied off the 220 kV Twizel bus and supplies us, Network Waitaki and Meridian Energy at 33 kV. We share the utilisation of one of the 220/33 kV transformers with Meridian Energy via the 33 kV bus A.

There is a ripple injection plant at the Twizel GXP, but is dedicated to Network Waitaki, due to the 33 kV switching configuration.

A single 33 kV subtransmission line provides supply to our 33/11 kV Twizel Village zone substation, which consists of four 11 kV feeders and one spare circuit breaker. At the zone substation we have two 33/11 kV power transformers, one with a capacity of 5/6.25 MVA and one of 3 MVA. The smaller transformer is kept in a de-energized state.

There is an indoor 11 kV switchboard with two distribution feeders supplying the Twizel township and two distribution feeders supplying the surrounding rural areas. We have an embedded network in the Twizel township providing supply to new developments in this area. The embedded network is supplied from two connection points at Manuka Terrace and Mackenzie Park.

TWIZEL REGION



7. INFORMATION DISCLOSURE REQUIREMENTS LOOK-UP

This table provides a look-up reference for each of the Commerce Commission's information disclosure requirements. The reference numbers are consistent with the clause numbers in the electricity distribution information disclosure determination (2012).

2.6	ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP Section where addressed
	Disclosure relating to asset management plans and forecast information	
2.6.1	Subject to clause 2.6.3, before the start of each disclosure year commencing with the disclosure year 2014, every EDB must complete an AMP that—	
	(a) relates to the electricity distribution services supplied by the EDB;	
	(b) meets the purposes of AMP disclosure set out in clause 2.6.2;	Section 2.8; Section 2.2.2; Section 6.1; Section 3.3
	(c) has been prepared in accordance with Attachment A to this determination;	Chapter 2.4
	(d) contains the information set out in the schedules described in clause 2.6.6;	
	(e) contains the Report on Asset Management Maturity as described in Schedule 13;	
2.6.2	The purposes of AMP disclosure referred to in subclause 2.6.1(1)(b) are that the AMP—	
	(1) Must provide sufficient information for interested persons to assess whether-	
	(a) assets are being managed for the long term;	Chapter 2.2.2
	(b) the required level of performance is being delivered; and	Chapter 1.2
	(c) costs are efficient and performance efficiencies are being achieved;	Chapter 1.3
	(2) Must be capable of being understood by interested persons with a reasonable understanding of the management of infrastructure assets;	Section 2.4.3
	(3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.	Appendix A.3.3
2.6.6	Every EDB must—	
	(1) Before the start of each disclosure year, complete and publicly disclose each of the following reports by inserting all information relating to the electricity distribution services supplied by the EDB for the disclosure years provided for in the following reports—	
	(a) the Report on Forecast Capital Expenditure in Schedule 11a;	Appendix A.2.1
	(b) the Report on Forecast Operational Expenditure in Schedule 11b;	Appendix A.2.2
	(c) the Report on Asset Condition in Schedule 12a;	Appendix A.2.3
	(d) the Report on Forecast Capacity in Schedule 12b;	Appendix A.2.4
	(e) the Report on Forecast Network Demand in Schedule 12c;	Appendix A.2.5
	(f) the Report on Forecast Interruptions and Duration in Schedule 12d;	Appendix A.2.6

Attachment		
	AMP Design	
1	The core elements of asset management—	
	1.1 A focus on measuring network performance, and managing the assets to achieve service targets;	Chapter 5.3
	1.2 Monitoring and continuously improving asset management practices;	Chapter 2.4
	1.3 Close alignment with corporate vision and strategy;	Section 2.4.3
	1.4 That asset management is driven by clearly defined strategies, business objectives and service level targets;	Section 2.4.4
	1.5 That responsibilities and accountabilities for asset management are clearly assigned;	Section 2.5
	1.6 An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets;	Chapter 3; Appendix A.6
	1.7 An emphasis on optimising asset utilisation and performance;	Chapter 5
	1.8 That a total life cycle approach should be taken to asset management;	Chapter 6
	1.9 That the use of 'non-network' solutions and demand management techniques as alternatives to asset acquisition is considered.	Section 5.3.3
2	The disclosure requirements are designed to produce AMPs that—	
	2.1 Are based on, but are not limited to, the core elements of asset management identified in clause 1;	
	2.2 Are clearly documented and made available to all stakeholders;	Chapter 3
	2.3 Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the EDB's asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets;	Chapter 2.4; Section 4.5.4
	2.4 Specifically support the achievement of disclosed service level targets;	Section 5.6
	2.5 Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment;	Chapter 6
	2.6 Consider the mechanics of delivery including resourcing;	Section 2.2.4; Section 5.6.4
	2.7 Consider the organisational structure and capability necessary to deliver the AMP;	Section 2.5; All sub sections
	2.8 Consider the organisational and contractor competencies and any training requirements;	Section 2.2.4; Section 7.2
	2.9 Consider the systems, integration and information management necessary to deliver the plans;	Chapter 6; Chapter 7
	2.10 To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs; and	Appendix A.1
	2.11 Promote continual improvements to asset management practices.	Section 7.5

Attachment		
	Contents of the AMP	
3	The AMP must include the following-	
	3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	Chapter 1
	3.2 Details of the background and objectives of the EDB's asset management and planning processes;	Section 2.4
	3.3 A purpose statement which-	
	3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes;	Section 2.1; Section 2.4
	3.3.2 states the corporate mission or vision as it relates to asset management;	Section 2.4.2
	3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	
	3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and	Section 2.4
	3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	Section 2.4.4
	The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest.	
	3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed;	Section 1.3; Chapter 6
	3.5 The date that it was approved by the directors;	Director Certification
	3.6 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates-	Section 2.5.1
	3.6.1 how the interests of stakeholders are identified	
	3.6.2 what these interests are;	
	3.6.3 how these interests are accommodated in asset management practices; and	
	3.6.4 how conflicting interests are managed;	
	3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	Section 2.5
	3.7.1 governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors;	Section 2.5.1
	3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and	Section 2.5.2
	3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	Section 2.2.4; Section 4.2
	3.8 All significant assumptions-	Section 2.2
	3.8.1 quantified where possible;	Section 2.2; Section 2.3
	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;	Section 5.2

Attachment		
	Contents of the AMP	
3	3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	Table 1.1; Appendix A.2.1 Appendix A.2.2
	3.8.5 the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b;	
	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;	
	3.10 An overview of asset management strategy and delivery; To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify- • how the asset management strategy is consistent with the EDB's other strategy and policies; • how the asset strategy takes into account the life cycle of the assets; • the link between the asset management strategy and the AMP; and • processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.	Section 2.4; Section 2.5
	3.11 An overview of systems and information management data; To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe- • the processes used to identify asset management data requirements that cover the whole of life cycle of the assets; • the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets; • the systems and controls to ensure the quality and accuracy of asset management information; and • the extent to which these systems, processes and controls are integrated.	Chapter 7.3 All sub sections. Section 7.5

Attachment		
	Contents of the AMP	
3	3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data;	Section 5.5
	3.13 A description of the processes used within the EDB for- 3.13.1 managing routine asset inspections and network maintenance; 3.13.2 planning and implementing network development projects; and 3.13.3 measuring network performance;	Section 5.6.2; Section 5.9; Section 1.2; Section 4.3; Section 4.5
	3.14 An overview of asset management documentation, controls and review processes. To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-	Section 2.4
	(i) identify the documentation that describes the key components of the asset management system and the links between the key components; (ii) describe the processes developed around documentation, control and review of key components of the asset management system; (iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy; (iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and (v) audit or review procedures undertaken in respect of the asset management system.	Section 2.4.3
	3.15 An overview of communication and participation processes; To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-	Section 2.4; Section 2.5
	(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and	Section 7.2
	(ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.	Table 1.1; Section 8.2
	3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	
	3.17 The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	

Attachment		
	Assests Covered	
4	The AMP must provide details of the assets covered, including-	
	4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	Section 3.1 and section 3.3
	4.1.1 the region(s) covered;	Section 3.3
	4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities;	Section 4.4
	4.1.3 description of the load characteristics for different parts of the network;	Section 5.9
	4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	Section 6.7, Appendix A5
	4.2 a description of the network configuration, including-	Section 3.2; Appendix A.6
	4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	Section 5.9.1
	4.2.2 a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	Section 5.9.1; Appendix A.6.1
	4.2.3 a description of the distribution system, including the extent to which it is underground;	Section 3.1; Section 3.3; Table 3.1
	4.2.4 a brief description of the network's distribution substation arrangements;	Section 3.3 All sub sections
	4.2.5 a description of the low voltage network including the extent to which it is underground; and	
	4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	Section 6.1.2; Section 6.8 All sub sections
	To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.	Figure 3.2; Appendix A.6
	4.3 If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	Appendix A.6.1
	Network assets by category	
4	4.4 The AMP must describe the network assets by providing the following information for each asset category-	Section 3.4
	4.4.1 voltage levels;	
	4.4.2 description and quantity of assets;	Section 3.2, Appendix A.6
	4.4.3 age profiles; and	Chapter 7
	4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	Chapter 7 Chapter 6
	4.5 The asset categories discussed in clause 4.4 should include at least the following-	
	4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	
	4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others;	Chapter 6
	4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	Section 6.5.3.5
	4.5.4 other generation plant owned by the EDB.	

Attachment		
	Service Levels	
5	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	Section 7.5
6	Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	
7	Performance indicators for which targets have been defined in clause 5 should also include- 7.1 Consumer oriented indicators that preferably differentiate between different consumer types; and 7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	Section 4 Section 4.4; Section 4.5
8	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	Section 4.3
9	Targets should be compared to historic values where available to provide context and scale to the reader.	Section 4.5
10	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	Section 4.5

Attachment		
	Network Development Planning	
11	AMPs must provide a detailed description of network development plans, including—	Section 2.2
	11.1 A description of the planning criteria and assumptions for network development;	
	11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	Section 6.1
	11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	
	11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss- 11.4.1 the categories of assets and designs that are standardised; and 11.4.2 the approach used to identify standard designs;	
	11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	Section 5.9
	11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network;.	Section 5.3
	11.7 A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision;	Appendix A.5
	11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand; 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	Section 5.2.1; Section 5.2.2; Section 7.5; Appendix A.5
	11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	Section 5.9
	11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and 11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	Section 5.3.5

Attachment		
	Network Development Planning	
11	11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including- 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; 11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and 11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	
	11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include- 11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months; 11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and 11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period; For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations.	
	11.11 A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated; and	Section 5.3.5
	11.12 A description of the EDB's policies on non-network solutions, including- 11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	Section 5.3.3; Section 5.4
	11.12.2 the potential for non-network solutions to address network problems or constraints.	Section 5.3.5

Attachment		
	Lifecycle Asset Management Planning (Maintenance and Renewal)	
12	The AMP must provide a detailed description of the lifecycle asset management processes, including—	
	12.1 The key drivers for maintenance planning and assumptions;	Chapter 6; Section 6.1
	12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	Section 6.1.8
	12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	Section 5.5; Chapter 6
	12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	Section 6.2.4
	12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	
	12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	
	12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	
	12.3.2 a description of innovations that have deferred asset replacements;	
	12.3.3 a description of the projects currently underway or planned for the next 12 months;	
	12.3.4 a summary of the projects planned for the following four years (where known); and	
	12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	
	12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	

Attachment		
	Non-Network Development, Maintenance and Renewal	
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; 13.3 a description of material capital expenditure projects (where known) planned for the next five years; and 13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	Chapter 5.3.3
	Risk Management	
14	AMPs must provide details of risk policies, assessment, and mitigation, including—	
	14.1 Methods, details and conclusions of risk analysis;	Appendix A.3
	14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	Appendix A.3.3, Appendix A.3.6
	14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	Appendix A.3.2
	14.4 Details of emergency response and contingency plans.	Appendix A.4
	Evaluation of performance	
15	AMPs must provide details of performance measurement, evaluation, and improvement, including— 15.1 A review of progress against plan, both physical and financial;	
	ï referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances; ï commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced; and ï commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.	Section 8.1
	15.2 An evaluation and comparison of actual service level performance against targeted performance; ï in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.	Section 7.5
	15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	Chapter 7; Appendix A.2.7
	15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Section 7.5
	Capability to deliver	
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; and	
	16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Section 2.5

COMPLAINTS PROCEDURE (FREE)

At Alpine Energy we recognise that your complaint is important to you, and to us. We will endeavour to contact you within two working days of receiving your complaint to discuss the concerns you have and how we can find a resolution. This is a free service. In the first instance, any complaints should be sent to:

ALPINE ENERGY LIMITED

Chief Executive Officer

PO Box 530, Timaru 7940

P: 03 687 4300 F: 03 684 8261

mailbox@alpineenergy.co.nz
www.alpineenergy.co.nz

INDEPENDENT COMPLAINTS

If you prefer a free, independent approach to your complaint enquiry please contact:

UTILITIES DISPUTES LIMITED

PO Box 5875, Lambton Quay, Wellington 6145,
Freepost 192682

P: 0800 22 33 47 or 04 914 4630
F: 04 472 5854

info@utilitiesdisputes.co.nz
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