ASSET MANAGEMENT PLAN 2019

EMPOWERING OUR COMMUNITY

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ASSET MANAGEMENT PLAN 2019

ALPINE ENERGY LIMITED

Planning Period: 1 April 2019 to 31 March 2029

Disclosure date: 31 March 2019

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DIRECTORS' STATEMENT

The purpose of our 2019 to 2029 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.

Just under 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 just more than 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 or 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 2019–2029.

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 2019–2029 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
28 March 2019	28 March 2019
Date	Date

CONTENTS

1. EXECUTIVE SUMMARY

1.1 GENERAL

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 maximise 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 the 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 by clearly identifying the consumer'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

Our 2019 AMP builds on the progress made over the last three years to improve this document. 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 as well as asset condition are also given. Asset condition and age 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.

We also draw from the capability of our subsidiary Infratec with a specific focus on new technologies and their application in New Zealand as well as the Pacific in general.

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 NETWORK

Our network plays an integral role in the economic development in South Canterbury. Despite developments in new technologies with a major emphasis on distributed generation through photovoltaics and battery storage, our network will continue to the main source of getting electricity to our consumers. Our network provides the conduit for the deployment and efficient use of new technologies while supplying bulk energy to industrial and commercial consumers where scale is the main challenge for economic deployment of new technologies.

As such it is imperative that we continue to provide a safe, reliable and resilient network while remaining flexible to change with the adoption of new technologies and changes in the regulatory environment.

We are a safety conscious company and health and safety is the first of our five core values. Since implementing our enterprise asset management system (ERP), we are now in a position to improve our understanding of asset health and criticality. Recent developments in the industry have refocused attention on this subject, and we have also increased our capital expenditure for asset replacement and renewal. While it is true that we have had extraordinary capital expenditure due to growth as the principal driver, significant portions of the growth expenditure also replaced old infrastructure. A typical example would be the rebuilding of single phase overhead lines with three phase infrastructure for dairy conversions and irrigation.

Over the last decade, we have been through a major economic growth phase in South Canterbury mainly due to dairy conversions, irrigation schemes and dairy processing. In many instances we had to be extremely flexible to be able to match the development timeframes of the industrial, commercial, irrigation and dairy developments. A number of large developments occurred after budgets had been set for the current regulatory period (DPP2). Some high-level statistics are:

- Oceania Dairy Limited constructed a dairy processing factory near Glenavy in 2014 with a network capacity installed of 15 MVA
- Waihao Downs Irrigation pump station was constructed and commissioned in 2015 with a network capacity of 4.5 MVA
- Holcim cement loading dock and storage facility at Timaru Port required an installed capacity of 6 MVA and was commissioned in 2015
- In 2018 we commissioned four new cables with a capacity of more than 30 MW between Timaru substation and the Washdyke industrial area with enough capacity to serve this busy industrial area for many years to come.

We also recognise network reliability as an important measure of empowering our community. Despite the quality breach for exceeding our quality targets in 2014 and 2016, our network reliability has been consistently improving since 2012. The decision by the government to review the tree regulations is welcomed due to impact trees that fall outside of the regulations have on our network.

In 2015, we surveyed 580 of our consumers on perceptions of reliability, inconvenience, community disruption, and price. The conclusion of the survey was that mass-market consumers have little if any willingness to pay additional line charges to improve the storm resilience of the network. However, this result does not in any way diminish our objectives to provide our consumers with the safest and most reliable electricity supply through efficient and prudent expenditure on our assets.

1.4 OUR INVESTMENT IN OUR NETWORK TO 2029

This AMP outlines our approach to asset management and the forecast capex and opex for the planning period of 2019 through to 2029 is depicted in Figure 1.1 and Figure 1.2. Expenditure is given in NZ dollars constant values as at 2018. 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).

Details of the makeup of our capex and opex are given in chapter°8.

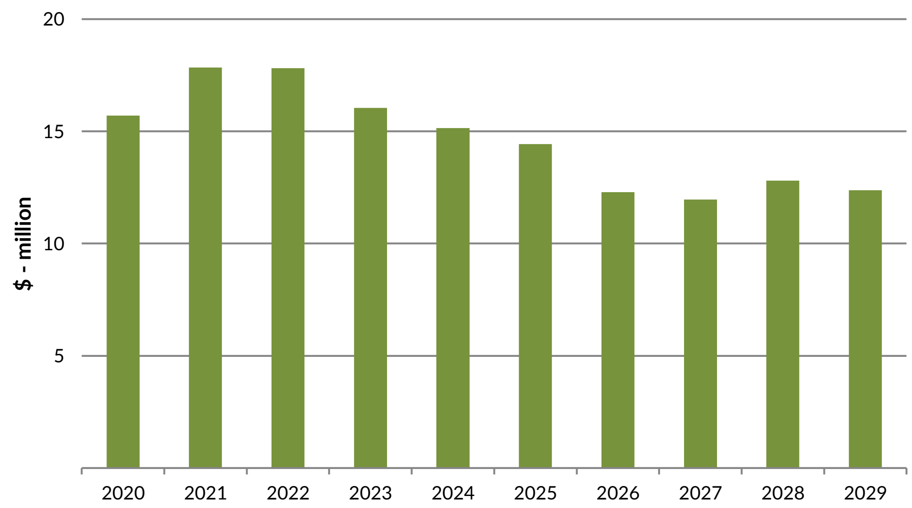

Figure 1.1 Total capex for the planning period.

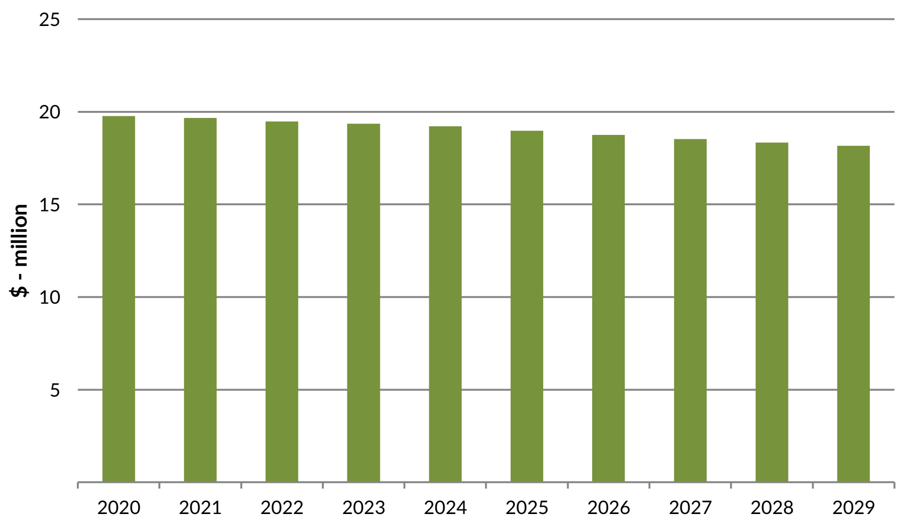

Figure 1.2 Total opex for the planning period.

1.5 EMERGING TECHNOLOGIES

It is our objective to build, operate and maintain an electrical distribution network that is open and accessible to new and emerging technologies. We are aware of the progress that has been made in solar generation and battery storage technologies and see these as becoming an integral part of the electricity industry. In this regard, we are well placed to facilitate and encourage the uptake of these technologies as and when they become economically feasible.

Providing accessibility will require that we review and constantly renew how we plan, design, construct and operate our network. Accommodating multiple direction power flows is a challenging and exciting future prospect which will allow peer to peer trading facilitated through our network. We are currently in the planning and negotiation stages with a major investor to realise a multi megawatt renewable generation installation to facilitate peer to peer trading as well as providing network support.

In 2017 we surpassed 1 MW in PV solar installations on our network and even though 2017 saw a reduction in the number of installations, applications picked up in 2018 with a record number of installations and overall capacity. We have also connected our second bio gas distributed generator on our network and expect this type of installation to increase due to the large number of dairy farms across our network and the increasing pressure on farmers to reduce carbon emissions.

With the continued deployment of advanced meters across our network we are now beginning to reap benefits from having more accurate network information at a consumer level. This is important since the facilitating of distributed generation and peer to peer trading will to a large extent be determined by the flexibility and capacity of our low voltage infrastructure. Network information obtained from advanced meters also allows us to pro-actively recognise and identify possible safety concerns at consumers' installations.

In the area of drone technology, there have also been widely reported successes in using this technology to more efficiently and effectively manage assets. In this regard, we have collaborated with other EDBs to investigate this application. While we have not yet progressed to any practical application of this technology we have recognised that there are various ways of utilising this technology. Our challenge is to find specific applications where this technology will be cost effective and successful. One area of application we are considering is the inspection of overhead lines during unplanned outages. It seems practical against the background of the mycoplasma bovis outbreak in South Canterbury where access to private land has become a bio security issue that is time consuming and costly and impacts on our network reliability statistics.

Figure 1.3 Official opening of our battery energy storage device connected to our network

Figure 1.4 Through our subsidiary Infratec we are involved in new technology projects such as this solar power station in Kiritimati.

1.6 ELECTRIC VEHICLES

The rapid growth internationally in the uptake of electric vehicles (EVs) is causing a fair amount of concern in terms of the increase in electricity demand and the ability of the electricity industry to accommodate this growth. The concerns are at a generation, transmission and distribution level. Transpower's *Te Mauri Hiko – Energy Futures* report deals to a large extent with the concerns at the generation and transmission levels. The implications for distribution companies should not be underestimated.

We regard the biggest challenge that we could possibly face in this area would be realised through government policy that negates the commercial forces of the market. The second biggest challenge is the continued reduction in prices of EVs and batteries that can be deployed at a consumer and a network level. Cheaper batteries would result in more economical storage especially at a consumer level, which would make combined PV and battery installations much more affordable from an investment recovery perspective.

Our approach to these challenges is to stay abreast of development in the international as well as the national arena through collaboration with our peers and industry players. As far as our distribution network is concerned we are busy putting systems and tools in place that will allow us to model and simulate realistic scenarios with respect to EV uptake, charging of batteries, and behavioural patterns. We have to guard against premature investment that could result in stranded assets or 'gold plating' of our network, while still being able to respond in accommodating the connection of distributed generation and increased supply requirements for the charging of EVs and other batteries. More details are given in section 5.4.

2. INTRODUCTION

This Chapter outlines the purpose of our AMP and details some key assumptions. It also presents our asset management framework (AMF) including objectives and responsibilities for asset management at all levels in our organisation.

2.1 THE PURPOSE OF THE PLAN

Our AMP provides an insight into and an 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 2012-consolidated 3 April 2018, published 3 April 2018.

2.2 KEY FACTS AND ASSUMPTIONS

2.2.1 LOAD DEMAND

The demand for new connections during 2018 was constant even after the improvement in milk pay-outs from the dairy companies, and a reduction in irrigation connections. Growth in demand is generally driven by irrigation, industrial, commercial, and domestic subdivision connections and extensions. Lately we have had much activity in the area of subdivisions and industrial development. With the government withdrawing support for the Hunter Downs irrigation scheme, we have experienced a reduction in the number of on farm irrigation developments.

We recognise the fact that the economy depends on a secure and reliable electricity supply. Investment in our network will ensure that the necessary network capacity is available to support increasing demand. This plan assumes the demand forecast will be as detailed in section 5.10 for the various regions.

It is important to note the load demands as detailed in this AMP do not include any potential or speculative development for which a formal supply application has not been submitted. To do so would distort our budgets and portray a potential unrealistic expenditure profile.

2.2.2 CAPITAL INVESTMENT REQUIREMENTS

We have reported network capital investment over ten 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. Some of these could have a substantial impact on our budgets. The proposed spend on capital investment projects is summarised in Chapter 8.

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 service level agreements for the 2019/20 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 new connections projects, our consumers can obtain the services of any network approved contractor.

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

For the 2019/20 financial year, we intend to make approximately 15% of our total network expenditure contestable through competitive tenders. We plan to gradually increase this percentage to 50% over the next three years.

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. This AMP 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.

2.3 NETWORK AND ASSET OVERVIEW

We supply electricity to over 33,121[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 $212 million.

Electricity is delivered to our network via seven grid exit points (GXPs) with Transpower and one embedded generator at the Opuha dam. The network delivered 807 GWh of energy and had a half hour average coincident maximum demand of 146 MW[3] in 2017/8 regulatory period. Energy consumption is down from the previous high of 836 GWh and the half hour average coincident maximum demand is up from 137 MW.

Our network is made up of the asset fleets and populations as depicted in Table 2.1. The network is in a good condition, and fleet details are discussed in Chapter 6.

[2] As at 31 March 2018

[3] Recorded on 8 December 2017 (16:30).

Table 2.1 Asset fleet and populations as at 31 March 2018

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, with 	25 power transformers, 	16 switchboards 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 	33,121 ICPs supplying our consumers. 

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 illustrated in the AMF depicted in Figure 2.1 and represents a suite of documents that describe how we manage our assets throughout their lifecycle. This suite of documents is being developed, and at the time of this publication, we have completed most documents except for some low value/critical asset fleets.

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) as detailed in Appendix A.2.7. Planned improvements are detailed in section 7.5.

2.4.2 CORPORATE OBJECTIVES

2.4.2.1 MISSION

Our mission is to empower our community…

- By helping South Canterbury prosper, through safe, reliable, secure infrastructure
- Through the return and accrual of value in yield and investment for our shareholders
- By helping our businesses achieve better business outcomes
- Through the enduring relationships and interactions we have, helping make South Canterbury the place to live
- By helping grow our future Olympians and community stars (scholarship and sponsorship)

2.4.2.2 BUSINESS GOALS

- **Shareholders** - to pursue business policies that maximise the value of the company in the medium and long term.
- **Consumers** - to deliver consumers with 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.

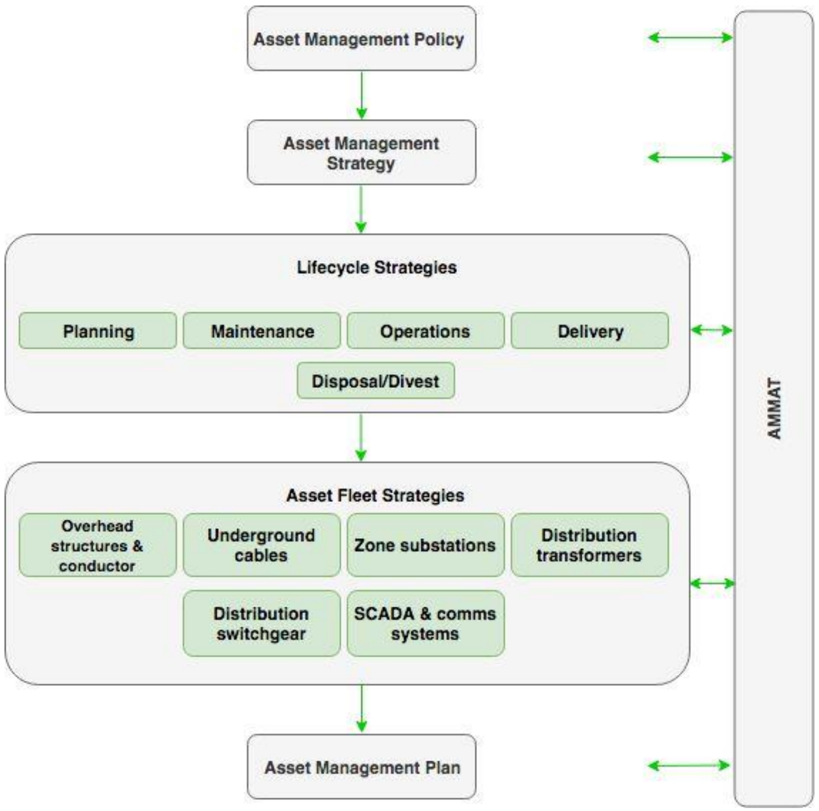


Figure 2.1 Asset Management Framework

2.4.3 ASSET MANAGEMENT POLICY

Our *Asset Management Policy* aims to align our asset management activities, as a service-orientated company, to our corporate objectives.

The objectives of this policy are to:

i) provide the framework for our management of the distribution network assets to better align with the ISO 55000 standard

ii) guide the development of our network asset management strategies and objectives

iii) 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 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 are 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 affect them
- complying with all applicable statutory and regulatory requirements by 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 health and safety always as our first company value, it is appropriate that **health and 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.
- 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** to achieve our company goals and objectives.

2.5 RESPONSIBILITIES FOR ASSET MANAGEMENT

The responsibilities for asset management are set out in Figure 2.2 below.

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 TDHL
- 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
- 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.

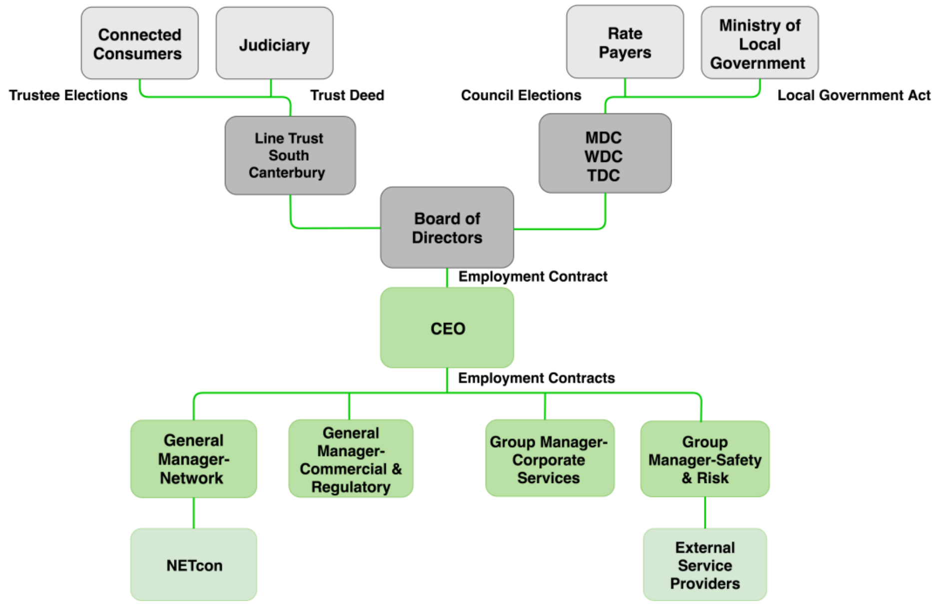


Figure 2.2 Accountability and mechanisms for asset management

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 functions and provides commercial support.

2.5.3 NETWORK DEPARTMENT

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 Consumer Service team, to meet the requirements of our growing network.

2.5.3.3 MAINTENANCE & ASSET INFORMATION

The Asset Maintenance and Information team are 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. The team is also the custodians of all asset data and information systems such as GIS, EAM 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).

2.5.3.5 CONSUMER SERVICES

The Consumer 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.

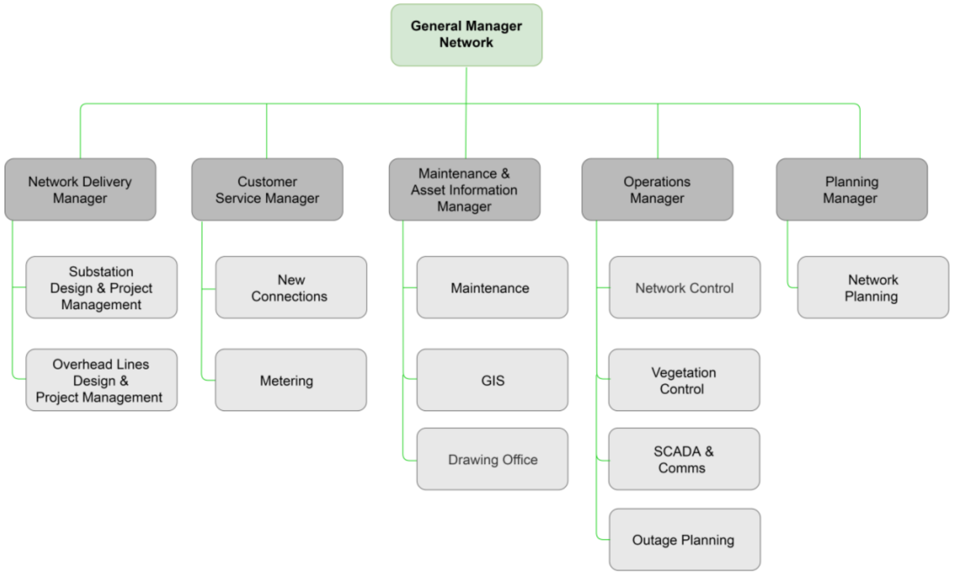


Figure 2.3 Accountabilities for asset management at network level

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 given.

3.1 OUR NETWORK AREA

Our network stretches over 10,000 km^2, bounded between the Rangitata River in the north and the Waitaki River in the south. To the west, our supply extends to the southern alps as far as Mt Cook Village, while the coast is the natural eastern boundary, as shown in Figure 3.1[4]. The three district councils—MDC, TDC, and WDC—provide infrastructure assets across the area.

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 up 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 110 kV, 33 kV and 11 kV at the seven points of supply described in Section 3.3:

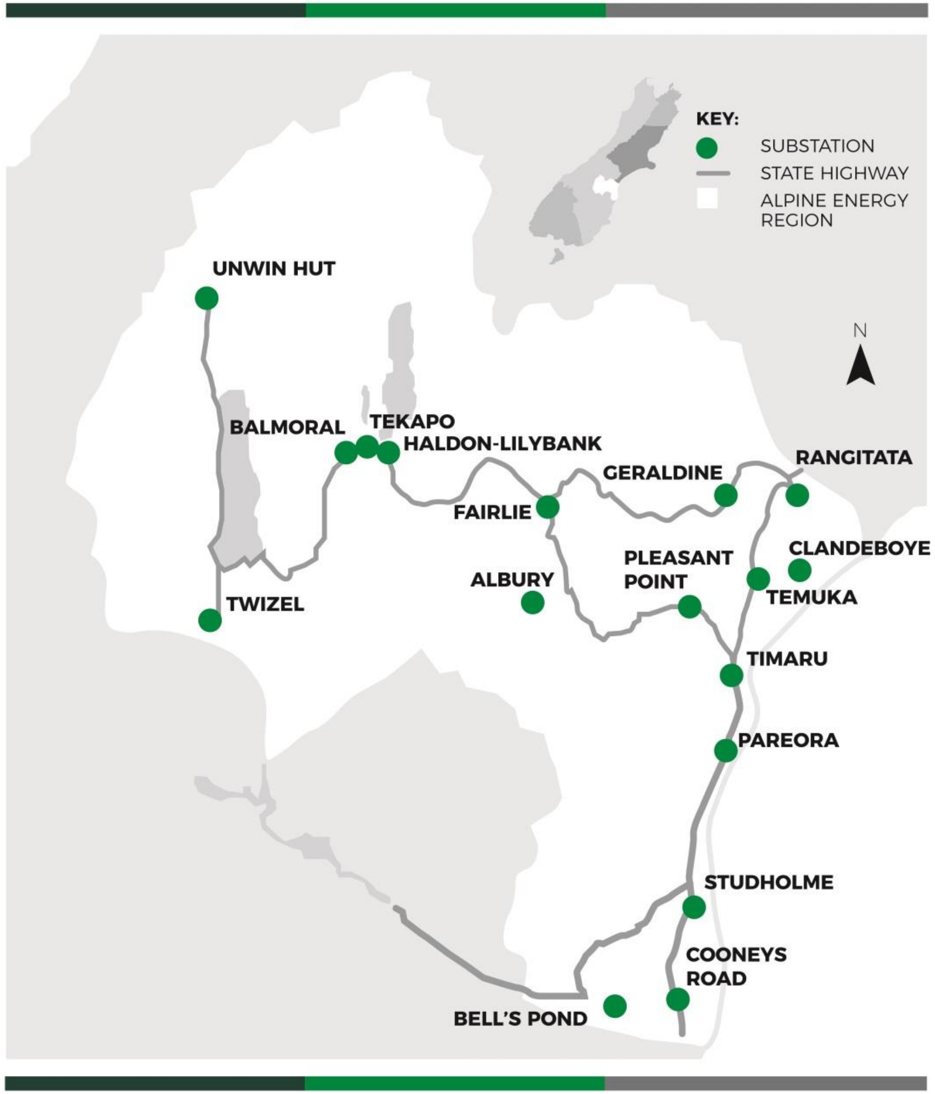


Figure 3.1: Our network area

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

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

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

In general GXPs have N-1 secure[5] capacity except in cases where the overall demand or load criticality does not justify the expenditure to have a secure supply. An example of this is Albury. 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 5.10.

3.3 REGIONAL NETWORKS

Our history as a utility included mergers and acquisitions that have led to a wide range of legacy asset types and architectures. 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 5.10.

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

Table 3.1 Regional network statistics

Measure	ABY	BPD	STU	TKA	TMK	TIM	TWZ
ICPs	1645	622	3333	893	6861	18185	1550
O/H (km)	590	202	552	250	915	944	62
U/G (km)	26	17	42	58	144	436	36
Zone subs.	2	2	1	4	5	3	1
Peak demand(MW)	4.95	11.67	14.79	4.75	54.24	67.42	13.29
Energy consumption (GWhr)	13,578 -11,339 *	38,16	57,12	19,26	275,78	349,95	14,165

* due to Opuha generation

[5] See definition of security in Table 4.1

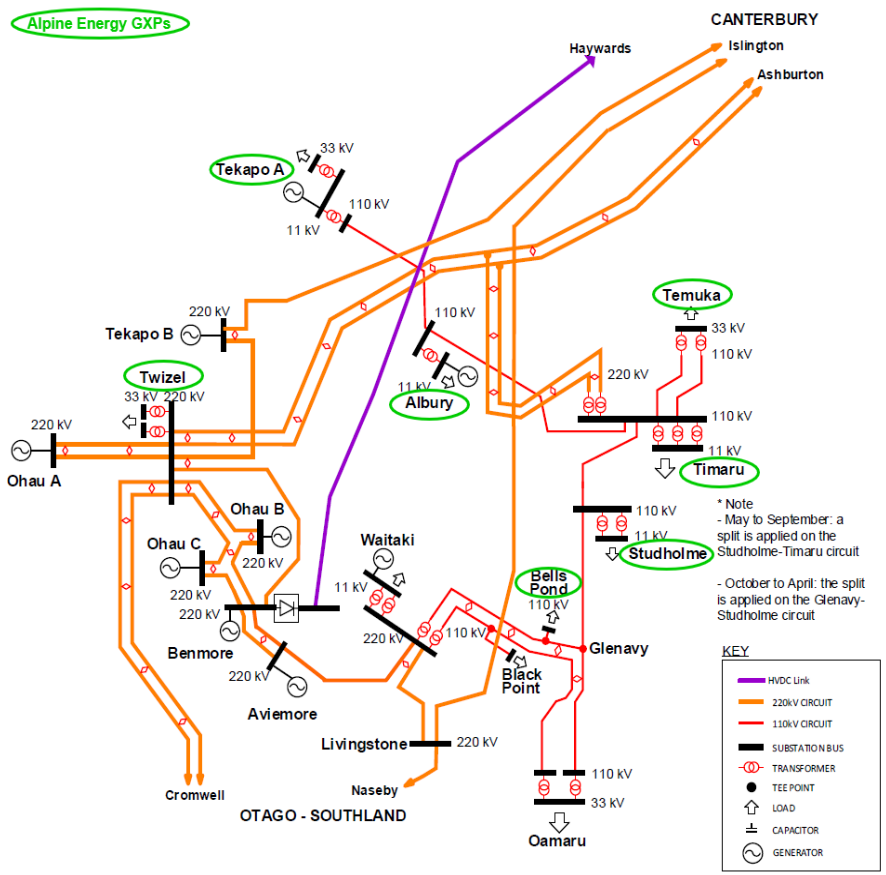


Figure 3.2: Transmission grid and GXPs

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 **Error! Reference source not found.**

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 dairy processing and on farm dairying irrigation.

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 (Bells Pond and Cooneys Road) and nine feeders in total.

Bells Pond was initially constructed in 2009 and the Cooneys Road zone substation in 2013. Overall both zone substations are in excellent condition 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 5.10.2.1.

We are currently in discussions with Transpower and Network Waitaki Limited in relation to the building of a new GXP off the Islington-Livingstone 220 kV transmission line. This GXP will replace the supply to the Oamaru and Blacks Point substations that are currently supplied from the two Waitaki 110 kV circuits. This would free up 60 MW of additional capacity for our Bells Pond and Studholme GXPs for future load growth.

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 Lilybank 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. Our infrastructure 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 5.10.7.1 and 5.10.4.1 respectively.

Initial dairy conversions and irrigation developments have slowed due to land use and discharge constraints.

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 are 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 5.10.5.1.

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

3.3.5 TIMARU REGION

The Timaru region encompasses 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 5.10.6.2.

3.3.6 STUDHOLME (WAIMATE) REGION

The Studholme supply region covers an area 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.

The Studholme GXP supplies this entire region. Our network 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 220 km of overhead lines in the first two years of the planning period.

Major replacements and upgrades will be required if there is an increase in Fonterra's dairy factory demand requirements. The current supply is considered secure but without the capacity to meet any of the above mentioned increased demand requirements. See section 5.10.3.1 for more details.

STAKEHOLDER INTERESTS & PERFORMANCE

4. STAKEHOLDER INTERESTS

4.1 OVERVIEW

This chapter details our stakeholders and how we accommodate their interests in our asset management practices. One of the objectives of our AMP is to effectively communicate to our stakeholders with a specific focus on the interests of each. We also detail high-level performance against regulatory standards and infrastructure investments and operating.

4.2 CONSUMERS

This section 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.

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

- to be more consumer needs focused,
- optimise delivery timeframes
- communication with our consumers reconnection to our network

We achieve this by clearly identifying the consumer'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 consumer's preferred contractor.

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

4.3 CONSUMER SERVICE LEVELS

We conduct 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 survey concluded 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 consumers for the past years. For the 2016 consumer survey we put a new series of questions that are more focused on the consumers' 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 at least 1 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 consumers of Alpine.

The peak demand in the 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 to have have two fairly large plants operating on our network. Details of these are given below.

Meat Processing	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	Installed Capacity
Holcim Cement – Timaru Port	6 MVA
McCain Foods - Washdyke	8.2 MVA
South Canterbury By-Products	2 MVA

Industrial	Installed Capacity
Coolpak Coolstores	3.45 MVA[6]
Polarcold Stores	4.5 MVA[7]
Juice Products	1 MVA
Cavalier Woolscourers	2.5 MVA

4.5 COMMUNITIES

With our network covering an area between the Rangitata and Waitaki rivers, from the coast all the way to Mt Cook, we supply the communities of Timaru, Temuka, Waimate, and MacKenzie basin and surrounding areas. Directors through our ownership structure represent these communities on our board.

A shareholder report is produced and presented to our shareholders monthly. Shareholder meetings consist of a half-yearly meeting and the annual general meeting. The main items on the agenda for these meetings are financial performance, strategy and approval of the annual report.

In addition our chairman and CEO meets with individual shareholders on a regular basis as required.

Increasing demand for immediate information during planned and unplanned events on our Network has led to our Facebook and WWW being monitored 24/7 since August 2018; this is extremely successful, with a significant drop in outage-related complaints.

For the period 31 January to 31 July 2018, five outage complaints were recorded. For the period 15 October 2018 to 15 March 2019 two outage complaints were recorded.

However, we understand this is not sustainable given our small communications team. We are now working with an app/workflow/text alert developer to scope and build a mobile device app to communicate power-related events, for engaging and informing our consumers/shareholders during outages.

[6] Approximately 2 MVA is shared with other consumers

[7] Approximately 1.5 MVA is shared with other consumers

4.6 RETAILERS

There are currently 21 retailers operating on our network. Almost 44% of our consumers are served by one retailer.

Except for six large consumers that we directly invoice for electricity line charges, our line charges are passed to consumers along with transmission charges and energy supply charges by the electricity retailers.

Historically we have always engaged directly with our consumers on planned power outages through card drops in the post as well as via email and direct telephone calls. Because of the relatively small number of ICPs and density across our distribution area this model has worked well and will be continued.

4.7 THE COMMERCE COMMISSION

Under part 4 of the Commerce Act, the Commission has the following responsibilities:

- Sets default or customised price/quality paths that lines businesses must follow
- Administers the information disclosure regime for lines businesses
- Develops input methodologies

We actively engage with the Commission on various aspects of the regulatory regime through submissions, letters and more informal communication such as email and phone calls. The importance of the function of the regulator is understood, and we aim to comply with all regulatory obligations through the various submissions and information disclosures that we provide.

4.8 LEGISLATIVE AND REGULATORY BODIES

Foremost on the list is the Health and Safety at Work Act that came into force on 1 April 2016. We believe our processes and systems meet all the requirements of the Act. WorkSafe regulates the safe supply of electricity services through regular audits.

In terms of all asset lifecycle stages, the following applies to us:

- The Electricity Act
- Electricity (Safety) Regulations of 2010 stipulates the requirements for the electricity industry and mainly focuses on ensuring the electricity supply system does not present any significant risk or harm to the general public or damage to property.

- Codes of Practice
    - NZECP 28 - Code of Practice for Selection and Installation of Cables
    - NZECP 34 - Code of Practice for Electrical Safe Distances
    - NZECP 35 - Code of Practice for Power System Earthing
    - NZECP 46 - Code of Practice for High Voltage Live Line Work

The Electricity Authority regulates the operation of the electricity industry and has jurisdiction over our activities as they relate to the electricity industry structure, including terms of access to the grid, use of system agreements with retailers, as well as metering, load control, electricity losses and distribution pricing methodologies.

It is our target to have full legislative compliance. 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 business. Our executive management team reports to our board quarterly on compliance with all legislation applicable to their area of responsibility.

4.9 PERFORMANCE REQUIREMENTS

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

4.9.1 HEALTH & 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 public, third-party incidents, and Alpine Energy worker 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 4.1 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.

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 leaks and hence we maintain a register for the recording of the total volume of gas contained within our equipment. We also use 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.

4.9.2 LEGISLATIVE COMPLIANCE

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 – Electrical Safe Distances
- Electricity Industry Participation Code – particularly applicable to distributed generation and protection relays

The quarterly results are reported to our board.

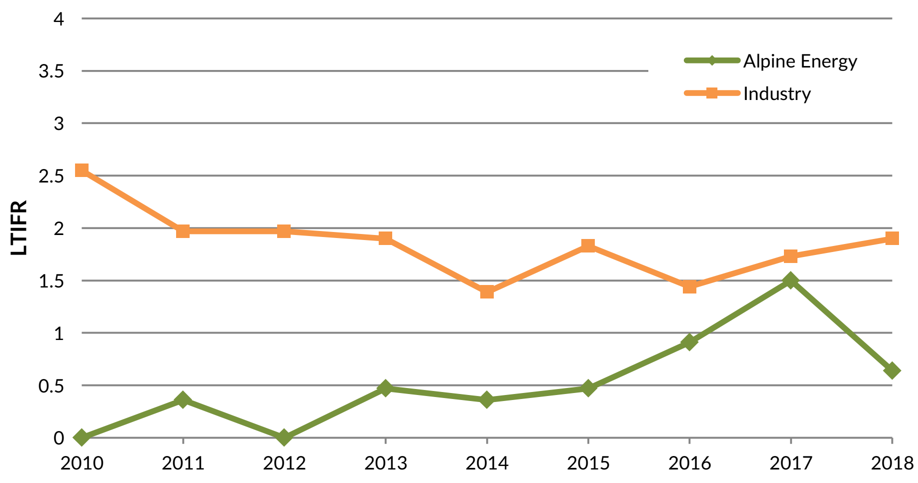


Figure 4.1 Normalised LTIFR

4.9.3 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 a meter by meter basis. The ownership of the data on the meter is a contentious issue. We aim 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 involve collaboration with the affected party. This often involves detailed engineering modelling and specialised measurements to be taken to appropriately deal with the issues appropriately.

4.9.4 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 performances against these two measures are given in the figures below.

As shown by the trend line, our SAIDI performance has been improving steadily over the last ten years. The adjustment in the DPP limit in 2011 followed an investigation of previous breaches where it was recognised that the previous limit levels were unrealistic. An independent report[8] on our reliability found that:

- "it is probable that the threshold was set too low due to inaccurate and understated historical SAIDI and SAIFI data,
- the TMED adjustments for the 2006 snowstorm did not account for the extended post-event impact on the AEL network,
- asset management practices and resources have, in the past, not enabled AEL staff to understand their network sufficiently and operate proactively at a strategic level."

Chapter 7 deals with improvements made with respect to asset management and capability.

[8] *Report on the reliability performance of Alpine Energy*, 13 April 2012, Produced for Commerce Commission by Strata Energy Consulting.

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 our power lines. We are comfortable that our network does not suffer from 'sustained material deterioration'. This view is supported in the historical SAIFI trend as depicted in Figure 4.3.

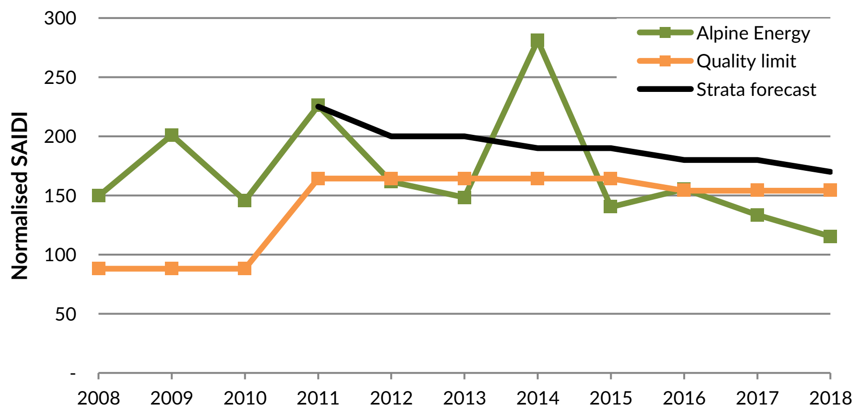


Figure 4.2 Historical normalised SAIDI performance

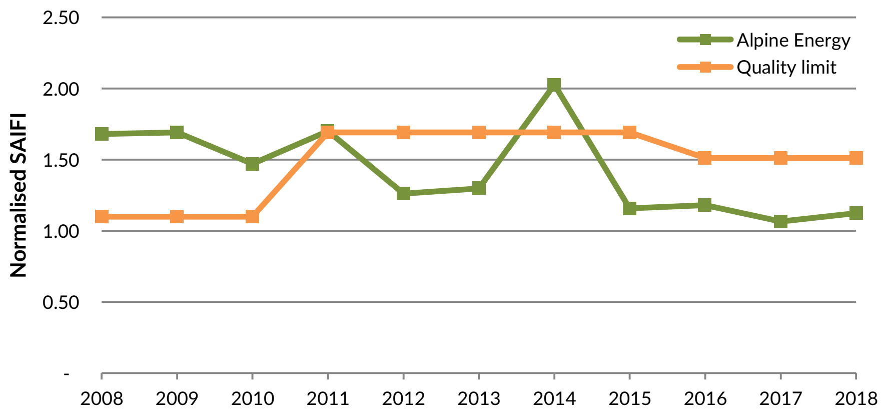


Figure 4.3 Historical normalised SAIFI performance

4.9.5 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 classifications

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 5.10.

4.9.6 WORKS PROGRAM COMPLETION

This section details our progress against the works program as detailed in our 2018 AMP. In summary, we have completed 84% of our capital works program. Due to the wet 2018/19 summer, we had to defer a number of overhead line replacement and renewal projects due to accessibility to private land. All these projects have been scheduled for the 2019/20 financial year. We have however also completed five overhead line replacement and renewal projects that were deferred from the previous financial year.

A material project to upgrade the supply to Fonterra Clandeboye's lactose plant was also put on hold by the consumer. Table 4.2 lists the material capital projects completed.

Table 4.2 Material projects completed

Project	Description	Variances?
PLP – Waitawa feeder	O/H line replacement & renewal	No material variances
PAR – Esk Valley	O/H line replacement & renewal	No material variances
STU – Otaio feeder	O/H line replacement & renewal	No material variances
STU – Waihaorunga feeder	O/H line replacement & renewal	No material variances
ABY – Cave feeder	O/H line replacement & renewal	No material variances
ABY – Raincliff feeder	O/H line replacement & renewal	No material variances
Two pole substation upgrades	Pole replacements, platform reinforcement and transformer replacements	No material variances
TIM – Ripple plant replacement	Replace existing ripple plant & building	No material variances (project still underway)
Upgrading of the Balmoral zone substation	Replace the existing BML substation with a new zone substation with increased capacity	No material variances
BPD – Second switch-room	Construction of a second 11 kV switch-room with 3 circuit breakers	No material variances

Our maintenance program for the year is 87% complete. The majority of the monthly and yearly inspections have been completed. Some five yearly RMU maintenance is still outstanding. These projects have been scheduled for the next financial year, and we expect to catch-up on all maintenance.

REGIONAL NETWORK DEVELOPMENT

5. 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
- demand forecasts
- our asset replacement program, and
- new applications for connection

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 factories 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, land intensification, and nitrogen discharge limits.

The increase in tourism and subdivisions in Tekapo and Twizel is now also a driver we use in our forecasting models.

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.

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 electric heating.

Figure 5.1 Demand forecasting process

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. Step increases are then added to the forecast.

When we establish the forecast system growth, we only include those new connections 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 new connections which involve a significant investment on our part.

The results of this process are detailed in the forecast of the regional plans in Section 5.10 below.

5.2.2 DEMAND FORECASTING

The total energy consumed in 2017/18 was 807 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 146MW[9]. 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.

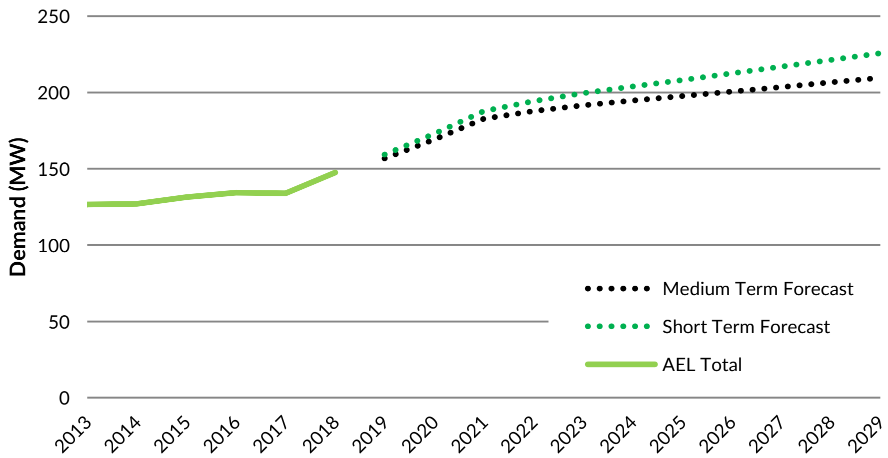


Figure 5.2 Total peak demand forecast

The lowest rated equipment determines the capacity of our distribution network 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.

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

Various inputs feed into our regional network development plans. These are shown in Figure 5.4.

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

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 through our risk management policy for network investment as described in Appendix A.3.

[9] As reported in our 2018 information disclosures

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*, (which is based on 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, minimise technical losses, and a reduction in maintenance and operating time through selection of maintenance-free equipment with minimum operational 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.

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 5.9.

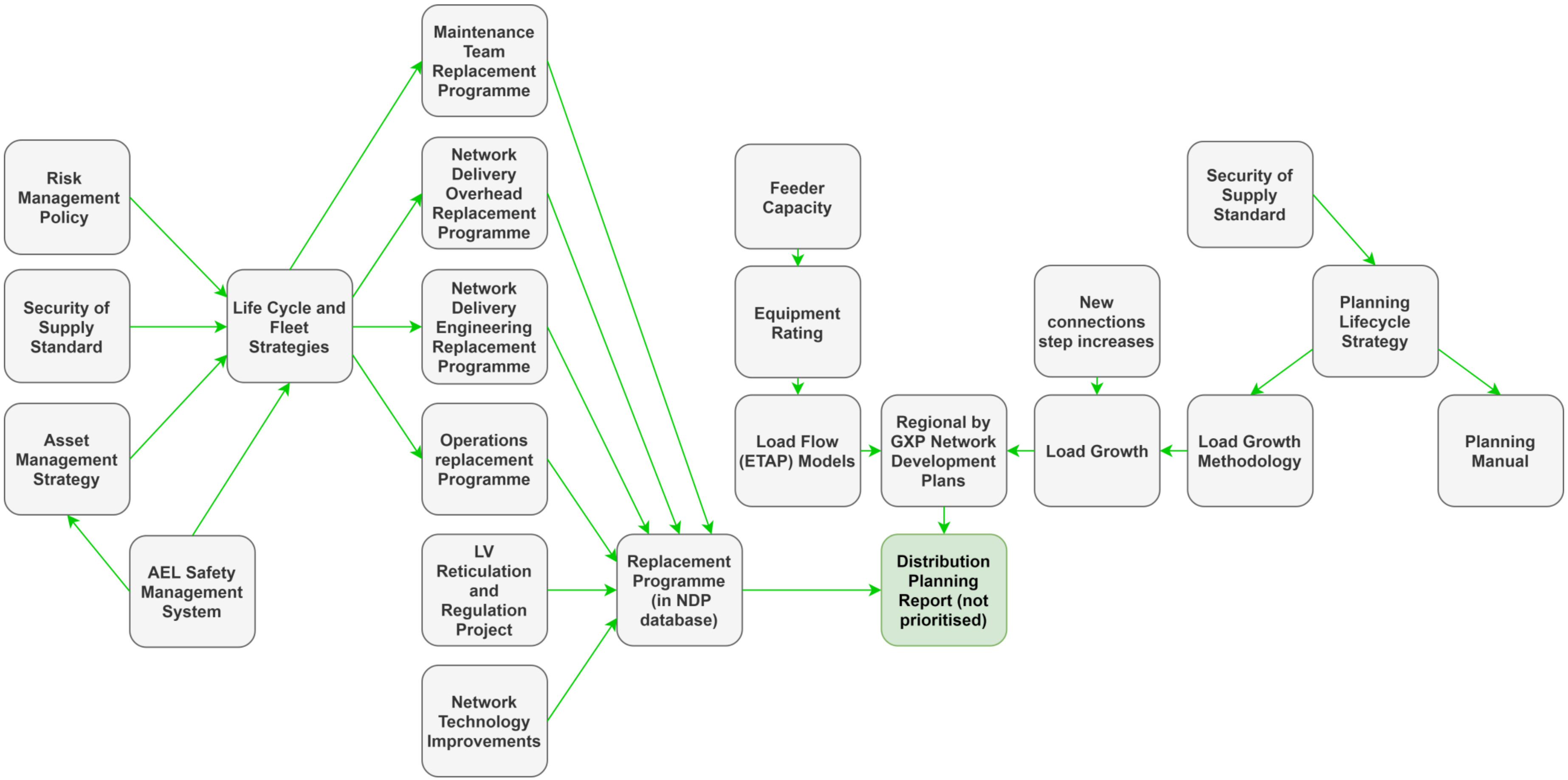


Figure 5.4 Regional development plan inputs

5.3.2 OPTIONS ANALYSIS

Once a trigger point has been identified, we define the risks from the issue, and consider 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. The do nothing option would only be adopted if the benefit-cost ratio of all other reasonable options were unacceptably low and if the 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 is a typical example of a 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 in adopting 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 the 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.
Emerging technologies	Emerging technologies, like a Battery Energy Supply System (BESS) may defer "traditional network upgrades.	A new connection load with a greatly variable daily load profile may be supplied by a BESS, negating the upgrade of the distribution transformer.
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 data from detailed risk assessments and populating the tool with this 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 levels at each point of supply are adequate to meet existing and future consumer load.

We do this by several approaches:

- Proactively analysis the performance of our 33 kV subtransmission and 11 kV distribution feeders using computer modelling[10]
- 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
- Application of emerging technologies.

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 (DG) 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.

DG also needs to be applied in such a way that the voltages at the consumers point of supply remain within statutory limits.

Consumers wishing to connect distributed generation on our network must ensure that a contractual agreement with a retailer is in place. 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.

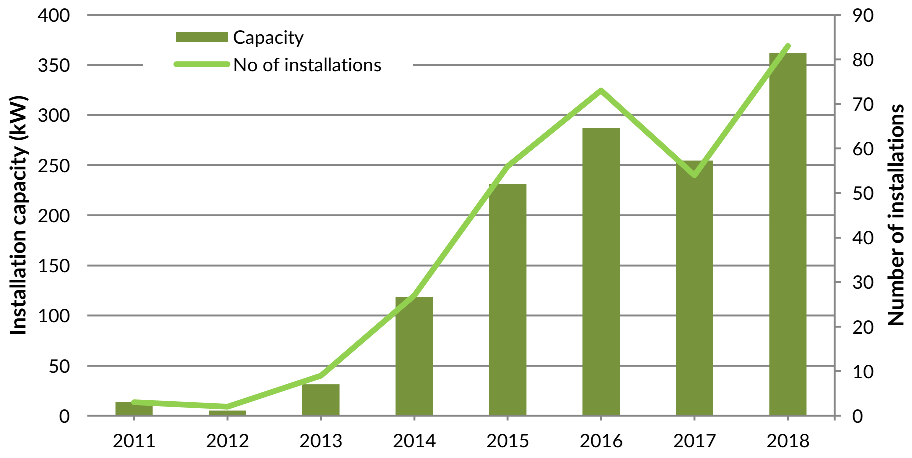


Figure 5.5 DG added to our network annually

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

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

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.

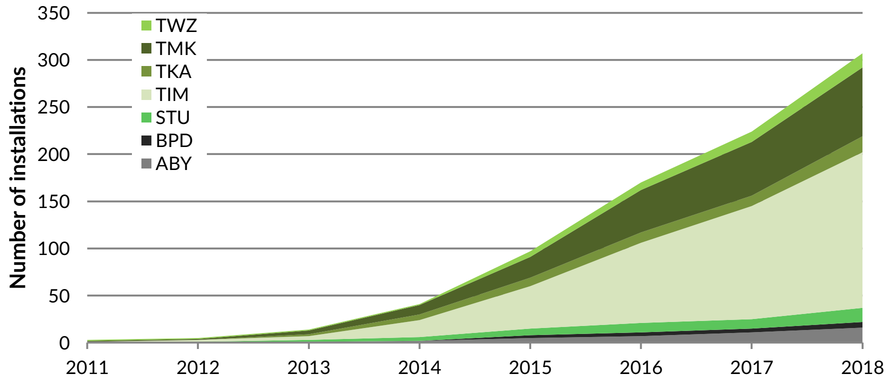


Figure 5.6 DG - accumulated installations by GXP

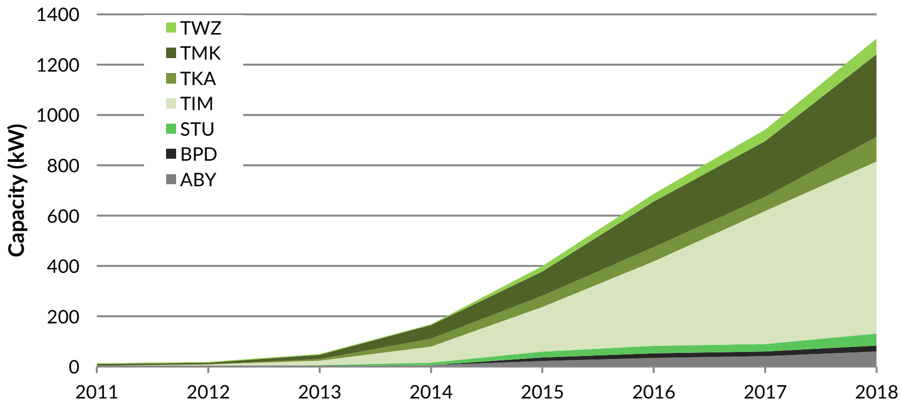


Figure 5.7 DG - accumulated capacity by GXP

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

5.4 ELECTRIC VEHICLES

The uptake of EVs and the associated growth in electricity supply to charge them will play an important role in our demand forecasting. In Transpower's *Te Mauri Hiko – Energy Futures* report it is stated that New Zealand's electricity energy consumption will double by 2050. This is based on a number of assumptions of which the main ones that would affect how we deal with this challenge are:

- assumption that EVs reach ~40 per cent market share by 2030 and ~85 per cent by 2050
- EVs will be cheaper to run, cheaper to buy, cheaper to maintain, and will have a longer lifespan than internal combustion engine vehicles

Demand growth affects our assets in two ways namely:

1. total energy demand that is required through our network assets and affects asset utilisation, and
2. daily peak demand which relates to the maximum capability of our assets supplying the demand.

We are in agreement with Transpower's *Te Mauri Hiko – Energy Futures* report that the anticipated acceleration in demand growth will only start from the mid 2020's based on current expectations of technology costs and uptake. Supplying an increased demand for the charging of EVs will impact our LV networks the most because households if left uninformed and uneducated will most like charge their EVs to coincide the current evening demand peak. This would double the current demand.[11] This doubling is also predicted in a report[12] prepared for Orion, Unison and Powerco and depicted in the figure below. In many cases this increase cannot be accommodated by the existing infrastructure without an EV charging management solution.

The European Commission issued a report[13] in 2013 where charging profiles were based on travel survey data across six[14] European countries. The report details individual charging profiles and aggregated load profiles by setting several parameters. Most importantly the projected charging time mainly occurs from 10 pm onwards as depicted in Figure 5.9. (weekdays are mostly the same with some variations for weekend charging)

[11] *How Electric Vehicles and the Grid Work Together*, IEEE power & energy magazine, November/December 2018.

[12] *"Driving change" – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand*, 2018. A report prepared by Concept Consulting Group Ltd for Orion, Unison & Powerco.

[13] *Projections for Electric Vehicle Load Profiles in Europe Based on Travel Survey Data*, - European Commission Report, 2013

[14] Italy, Poland, France, Germany, Spain, and the UK

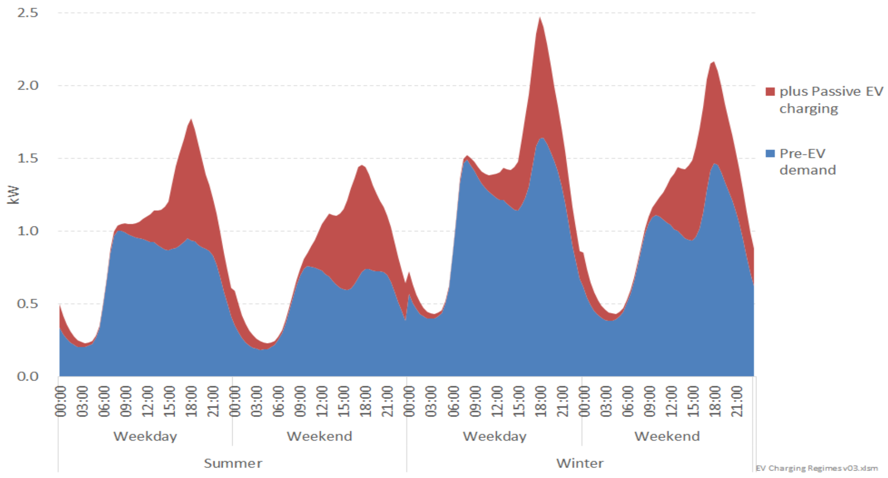


Figure 5.8 Passive pre- and post EV charging (source: Concept Consulting Group Ltd – Report prepared for Orion, Unison and Powerco, 7 March 2018)

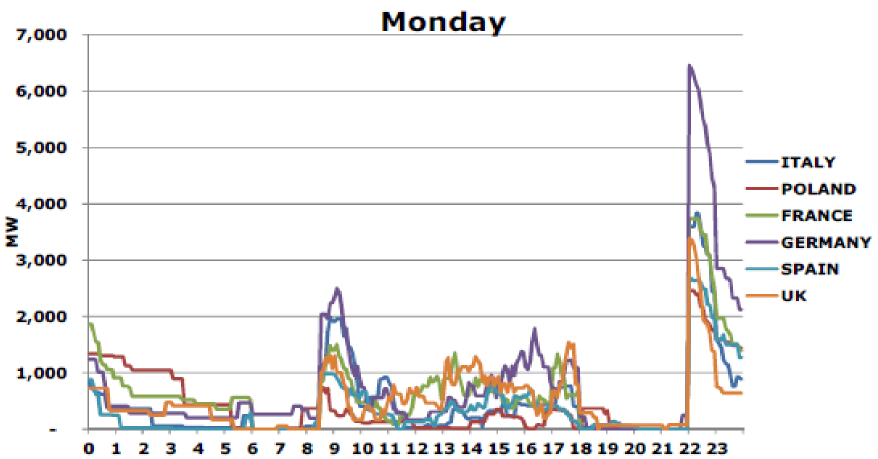


Figure 5.9 Typical weekday EV charging load profile (source: European Commission report – *Projections for Electric Vehicle Load Profiles in Europe Based on Travel Survey Data*, 2013)

The above demand profiles are very similar to the demand profiles for hot water cylinders heating. We currently control the peaks on our network through ripple plants and associated ripple relays. The same system is used to manage irrigation load in cases of network emergencies. We believe many of the challenges with EV charging can be addressed through an EV charging management solution that will control the when, where and how long EVs are charged. Smart meters could most likely play an important role in this regard. A controlled or active EV charging profile would then look as depicted in the figure below. From this it is clear that there is a limited and manageable increase in the peak demand.

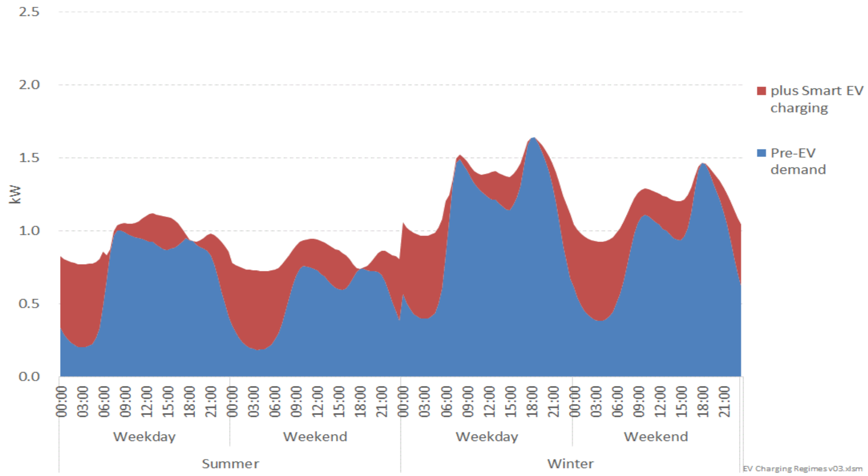


Figure 5.10 Smart pre- and post EV charging (source: Concept Consulting Group Ltd – Report prepared for Orion, Unison and Powerco, 7 March 2018)

Another area that can be investigated is the effect of pricing signals to influence consumers' EV charging behaviours. The Concept Consulting Group report referred to above makes the following conclusions:

- "A move to more cost-reflective approaches for charging for electricity is going to be necessary…" and
- "A possible alternative pricing approach to enable the adoption of emerging technologies like EVs, whilst minimising customer bill shock and without compromising carbon goals, is 'managed-charging' pricing which only applies to a household's EV demand."

In preparation for modelling various scenarios for demand forecast, we are doing the following:

- systematically fitting distribution transformers with smart meters to measure real time load profiles of the transformer,
- measure voltage profiles on a per phase basis for same transformers to assist us with load balancing and regulation through the adjusting of voltage taps,
- planning to confirm or update our LV network data through an asset walk-down/audit project,
- model our LV networks in our loadflow modelling tool (ETAP) to calculate the effects of PV penetration as well as EV charging scenarios,
- continue to participate in national forums on this topic and perusing local and international studies.

5.5 SYSTEM GROWTH & SECURITY

5.5.1 CONSUMER EXPECTATION

In our planning, we take into account our consumers' 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 through 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 18 Energy traders operating on our network.
- Specific contracts with consumers (for example Fonterra, Oceania Dairy Limited and Opuha Water Limited).

5.5.2 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 (from a GXP or other zone substation) into the zone 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 one trips or faults
- Provision of back-feed on the 11 kV from adjacent substations where sufficient 11 kV capacity and interconnection exists [15]
- 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 any existing security headroom.

We have developed our *Security of Supply Standard* (based on the EEA Guidelines for Security of Supply) for our network, which states 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, dairy and food 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 5.10.

We have a project underway to review our *Security of Supply Standard* to ensure alignment with stakeholder expectation, affordability and consideration of emerging technologies (for example battery storage).

5.6 REPLACEMENT & RENEWALS

When condition assessments indicate that an existing asset is at the 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 regarding 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 the end of life. Substation and plant inspections are undertaken either by the maintenance contractor as

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

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 capacity of the asset does not change).

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

5.6.1 ASSET HEALTH INDICES

Asset health reflects the expected remaining life of an asset and acts as a proxy for likelihood of failure. We have used asset health to inform our asset management approach for a number of our asset fleets. Using asset health indices (AHI) we can estimate the required future volume of asset renewals and forecast the health outcomes of our investment scenarios. We employ AHI in accordance with the Electricity Engineers' Association's (EEA) *Asset Health Indicator Guide: 2016*.

The AHI categories are defined as detailed in Table 5.3.

Table 5.3 AHI categories

AHI	Category Description	Replacement period
H1	Asset has reached the end of its useful life	Within one year
H2	Material failure risk, short-term replacement	Between 1 & 3 years
H3	Increasing failure risk, medium-term replacement	Between 3 & 10 years
H4	Normal deterioration, regular monitoring	Between 10 & 20 years
H5	As new condition, insignificant failure risk	Over 20 years

A typical AHI graph for an asset type will be as depicted in Figure 5.11. Detailed AHI data for most asset types is given in Chapter 6. By and large our AHI in this AMP is based on th age based assessment of the EEA's *Asset Health Indicator Guide: 2016.*

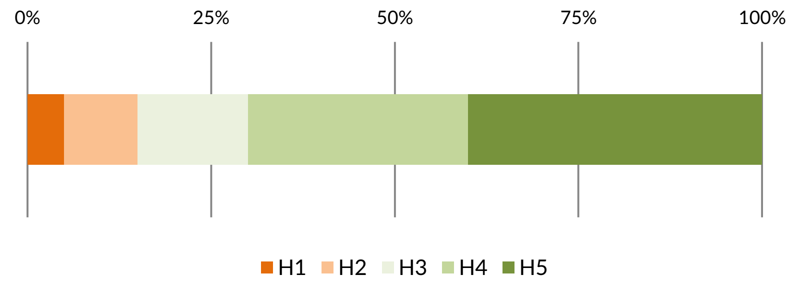


Figure 5.11 Example of asset health profile

5.7 RELIABILITY, QUALITY, SAFETY & ENVIRONMENT

5.7.1 SAFETY

With safety being our first value, our asset management activities are aligned to ensure our network is safe for public, contractors and staff. We achieve this through our *Safety Management-* and *Public Safety Management Systems* respectively. More details can be found in appendix A.4.

We consider safety in design with the assistance of the *Safety in Design* guide of the EEA. In particular safety is considered across all stages of the asset life namely construction, operation, maintenance and disestablishment. Where possible and appropriate we involve contractors responsible for the construction, operating and maintenance of the assets in the planning and design phases of projects. In many instances we execute repeat standards designs where safety in design was covered as part of the original design. Standard designs and industry and international standards forms the basis of all our designs. These include IEC, IEEE, NZ Codes of Practice etc.

5.7.2 QUALITY OF SUPPLY

5.7.2.1 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). 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 or excessive distributed generation (congestion) may cause voltages to be outside the regulatory requirements. Compliance with the regulations will trigger network investment projects, for example, a line upgrade.

5.7.2.2 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.

5.7.2.3 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.

5.7.3 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 4.9.4 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.

5.7.4 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.

5.8 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. The majority of our LV overhead distribution lines are 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 safety reasons.

5.9 CONSUMER CONNECTIONS

Every year we have many 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 landowners, or developers/civil surveyors. All costs associated with the additional requirements to extend the network as part of the consumer connection is funded by the requesting party as a capital contribution.

For two years in a row we have 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 2019. Small scale subdivisions where the landowners subdivide an existing property into one or two smaller sections have continued in the Temuka, Geraldine, Waimate and Timaru areas. This is aided by the Timaru District Council adopting a policy of in-fill[16].

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.

[16] Timaru District 2045 Growth Management Strategy

5.10 REGIONAL PLANS

This section summarises the network development plans for each of our seven planning regions as depicted in Figure 5.12. Each planning region is supplied by its own GXP from Transpower as shown in Figure 3.2.

We have developed Network Development Plans (NDPs) for each region and more detail demand forecasts for each region is given in Appendix A.5.

Material growth and security projects are projects above $1 M that will increase capacity and increase/maintain the required security of supply.

5.10.1 ALBURY

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 hydropower 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.

5.10.1.1 DEMAND FORECAST

Demand forecasts for the Albury GXP, and regional zone substations are shown in Figure 5.13 with further details provided in Appendix A.5.

Demand is growing slowly, and there are presently no known significant step increases from new connections to the network.

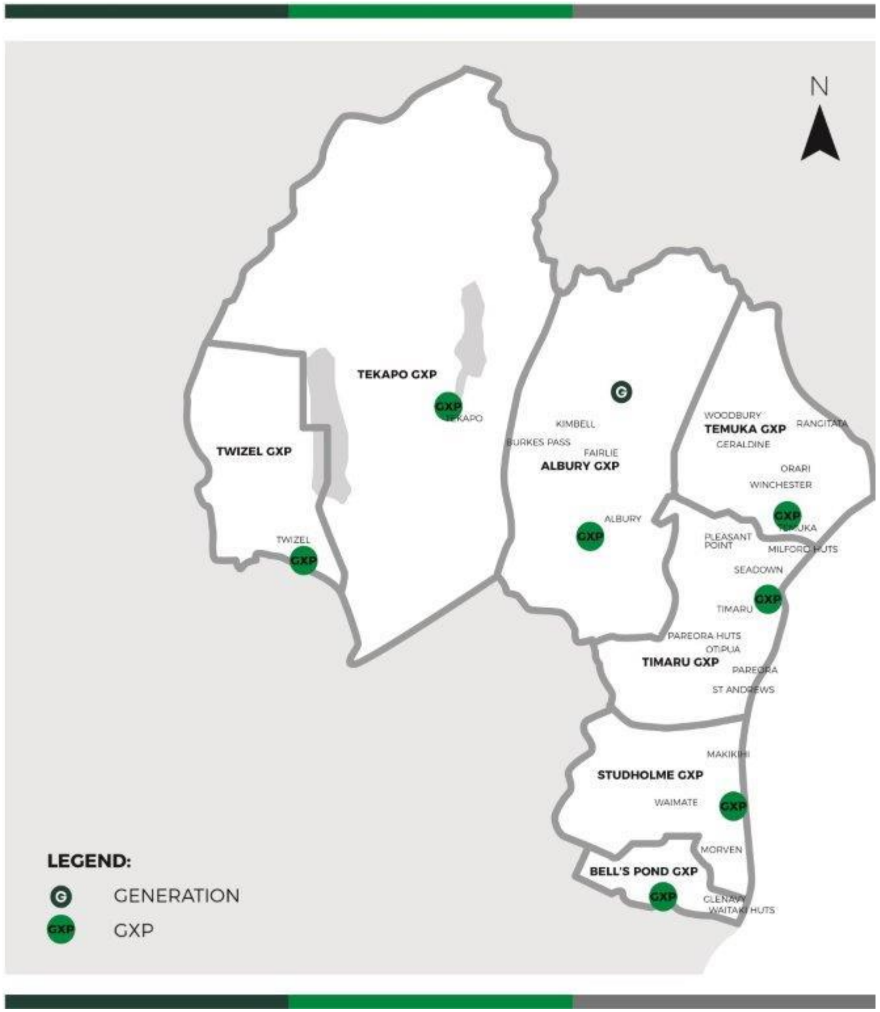


Figure 5.12 GXP map

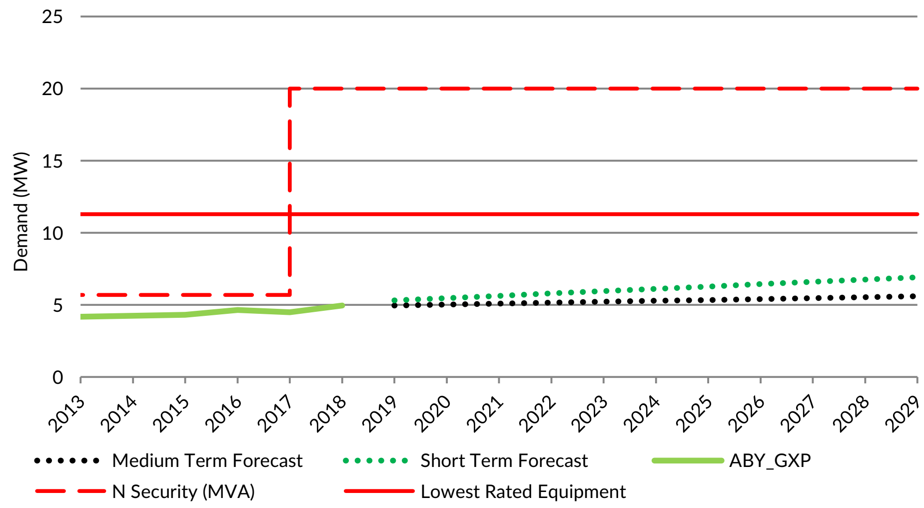


Figure 5.13 Albury GXP demand forecast

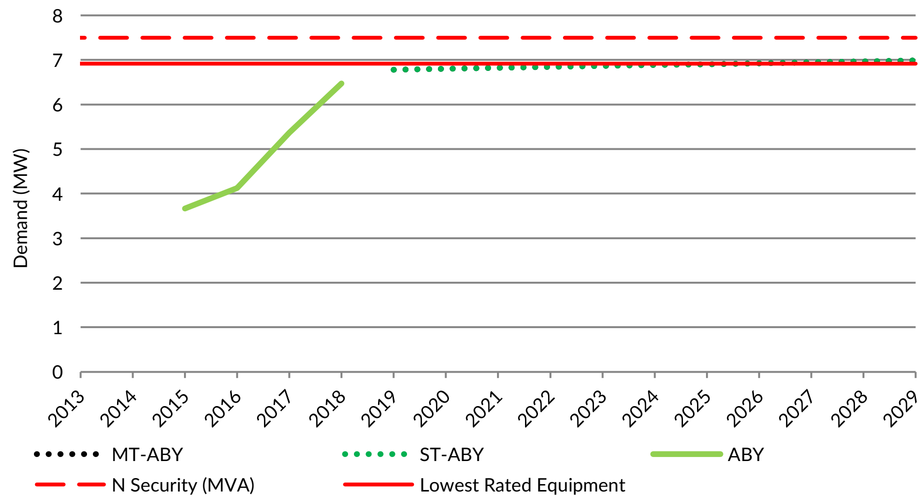


Figure 5.14 Albury zone substation demand forecast

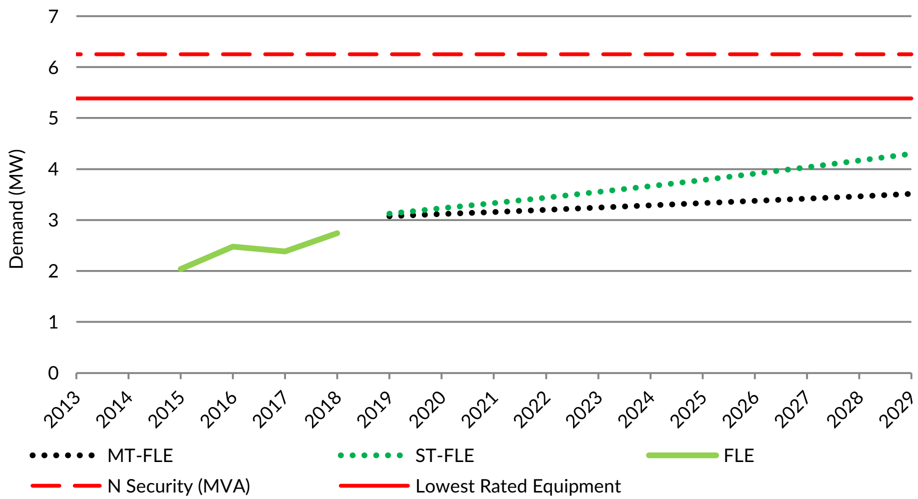


Figure 5.15 Fairlie zone substation demand forecast

Table 5.4. Albury region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)
Albury GXP	20.00	-	11.30	4.95	5.02	5.08	5.15
Albury zone substation	7.50	-	7.61	6.85	6.94	7.03	7.13
Fairlie zone substation	6.25	-	5.38	3.08	3.12	3.16	3.20

5.10.1.2 SECURITY OF SUPPLY

Table 5.5 Albury and Fairlie security of supply

Zone sub/load centre	Actual security level	Target security level	Configuration and options
Albury rural	N-0.5	N	Some load can be supplied by 11 kV feeders from Fairlie, Pleasant Point and Temuka zone substations.
Fairlie	N	N	Some load can be supplied by 11 kV feeders from Albury and Geraldine zone substation. Islanding Fairlie onto our mobile generator (limited capacity) or Opuha power station. The use of the Opuha power station requires negotiation with generation operator, careful islanding, does not have black start[17] capabilities, and does have speed control issues.

5.10.1.3 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[18]. Despite the limitation, this will still provide ample capacity for the planning period and beyond. The new transformer with a functional tap changer now allows the 11 kV voltage to be regulated, 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

[17] 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.

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

(Trustpower) is required. Therefore the Opuha power station is not considered in any security of supply considerations.

5.10.1.4 MATERIAL GROWTH AND SECURITY PROJECTS

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

5.10.2 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[19]

Network configuration

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

5.10.2.1 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 5.16 Bells Pond GXP demand forecast

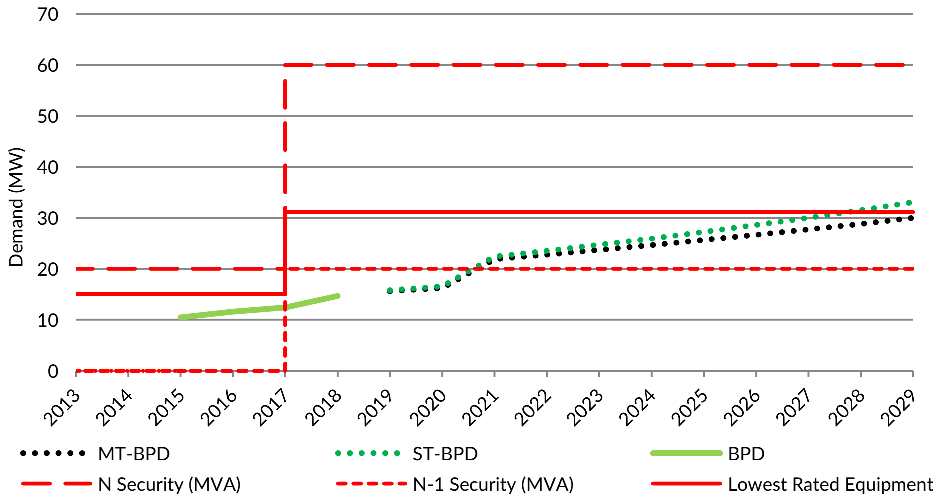


Figure 5.17 Bells Pond zone substation demand forecast

[19] www.mgiirrigation.co.nz

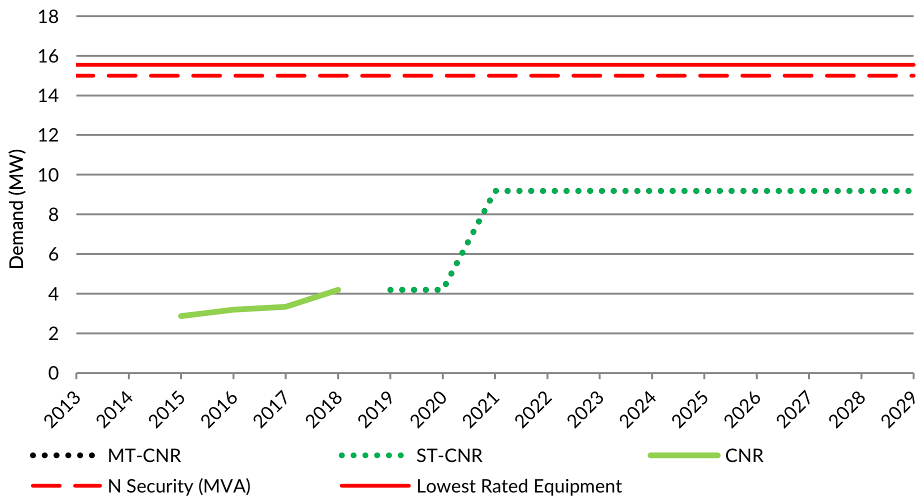


Figure 5.18 Cooneys Road zone substation demand forecast

Table 5.6 Bells Pond region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)
Bell Pond GXP	60.00	20.00	68.59	15.00	16.27	22.53	23.80
Bell Pond zone substation	60.00	20.00	30.06	15.63	16.26	21.91	22.78
Cooneys road zone substation	15.00		15.30	4.19	4.19	9.19	9.19

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 one has been commissioned with a load of 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.

5.10.2.2 SECURITY OF SUPPLY

Table 5.7 details the security of supply for the Bells Pond and Cooneys Road zone substations respectively.

Table 5.7 Bells Pond and Cooneys Road security of supply

Zone sub/load centre	Actual security level	Target security level	Configuration and options
Bells Pond rural	N-0.5	N	Some load can be supplied by 11 kV feeders from Studholme zone substation. 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's load on Studholme zone substation.
Dairy processing ODL	N-0.1	N	Supply is not presently N-1, as agreed by ODL. 0.5 MW[20] 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.

5.10.2.3 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[21] 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.

[20] Summer season

[21] Summer season

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 if 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, 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.

5.10.2.4 MATERIAL GROWTH AND SECURITY PROJECTS

This section is a summary of material 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 if ODL requests the 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 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.

Maintain N-1 security of supply by uprating/upgrading BPD T1

Estimated cost (concept)	Approximately $1.6 M
Expected project timing	2021

If the Bells Pond load exceeds 20 MVA, the security of supply will drop from N-1 to N.

An engineering investigation (in 2020) will determine if uprating the existing T1 transformer is an option. During this investigation, serious consideration will be given to new technologies/non network solutions due to the seasonality of the demand.

5.10.3 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.

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 operates the Studholme dairy factory, which is located close 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.

5.10.3.1 DEMAND FORECAST

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

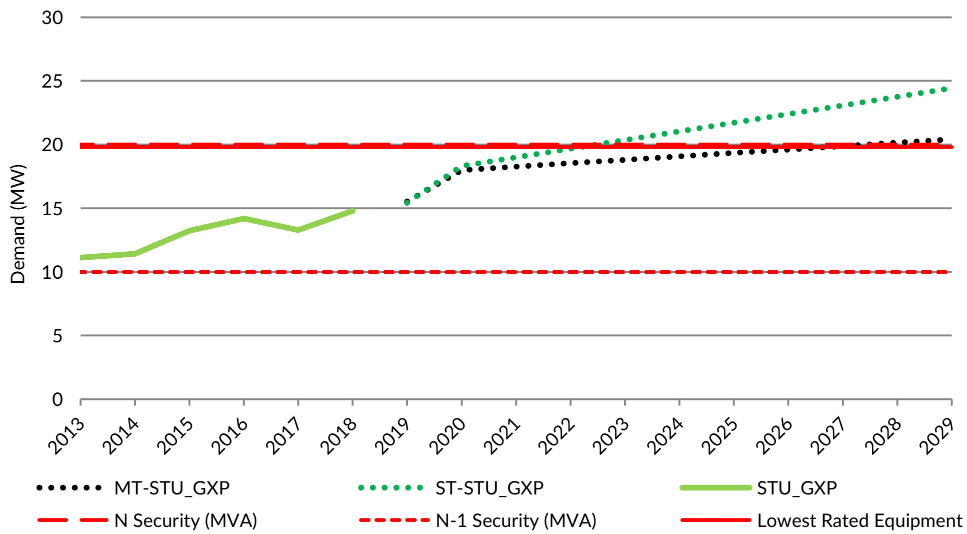


Figure 5.19 Studholme (Waimate) GXP demand forecast

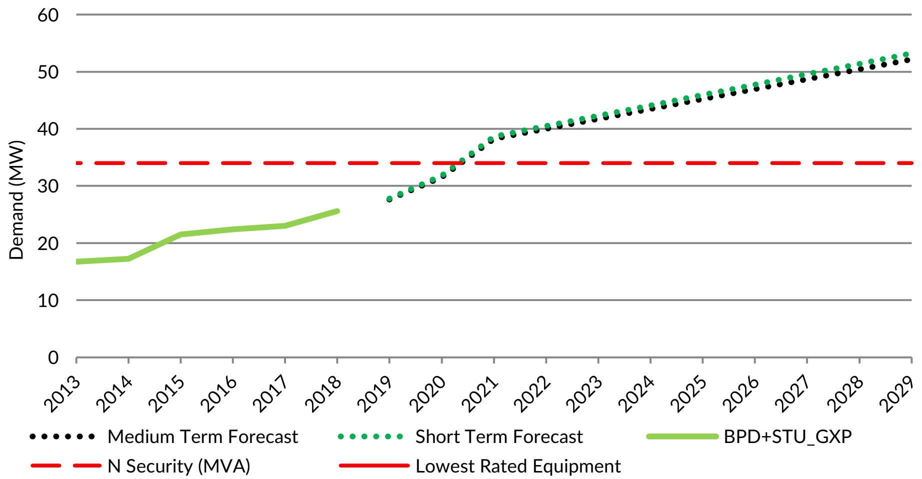


Figure 5.20 Bells Pond & Studholme GXPs combined demand forecast

Table 5.8 Studholme (Waimate) zone substation demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)
Studholme GXP	20.00	10.00	19.81	17.38	18.00	18.27	18.54

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

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.

5.10.3.2 SECURITY OF SUPPLY

Table 5.9 Studholme security of supply

Zone sub/load centre	Actual security level	Target security level	Configuration and options
Waimate residential	N-1	N-1 (switched)	Some load can be supplied by adjacent 11 kV feeders. Limited fault backup from Bells Pond.
Waimate rural	N-0.5	N-0.5	Some load can be supplied by 11 kV feeders from Bells Pond and Pareora.
Fonterra 11 kV	N	N	Load over 3 MVA requires consumer investment for dedicated feeders/cables. Present load is restricting load growth and increasing voltage problems towards end of feeders.

5.10.3.3 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 has 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 require network investments if new connection requests for additional load are received. In this instance we will issue a request for proposals for non-network solutions. 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[22] 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 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.

5.10.3.4 MATERIAL GROWTH AND SECURITY PROJECTS

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

Increase Transmission capacity to STU (and BPD) GXP

Estimated cost (concept)	Approximately $1 M
Expected project timing	2024/5

The combined STU and BPD available transmission capacity is 34 MW. It is expected that the load from these GXPs will reach this capacity in 2021. More capacity is available when the 110 kV transmission circuit is split at STU.

Options are being explored with Transpower and Network Waitaki. One option is to establish a new 220 kV GXP for Network Waitaki at Blacks Point. This could free up 60 MW of capacity at STU and BPD for Alpine Energy.

The budget estimate is to connect the second Waitaki 110 kV circuit into our Bells Pond GXP as well as the associated circuit breaker and protection upgrade. This expense is not in the current planning period budget due to the high level of uncertainty around the new GXP development for Network Waitaki.

Restore transformer security from N to switched N-1 by uprating/upgrading transformers at STU GXP

Estimated cost (concept)	Uncertain
Expected project timing	2021

The 110/33 kV transformers at STU GXP are owned and operated by Transpower. With the maximum demand now about 12 MVA, there is no longer switched N-1 transformer security. This project will explore (with Transpower) the best option to restore switched n-1 security.

While a transformer upgrade will be a Transpower funded project, we will be charged through the transmission charges regime and the costs will be a pass through to our consumers. Depending on the solution agreed with Transpower we will include a budget for any works on our assets.

Increase the number of 11 kV feeders out of the Studholme zone substation and reconfigure existing feeders.

Estimated cost (concept)	Approximately TBC
Expected project timing	2023

It is expected that due to load growth on various 11 kV feeders, there will be a need to reconfigure (and supplement) these feeders.

The feeders that will be constrained are:

- Otaio in 2027
- Waimate in 2023
- Studholme in 2023
- Morven in 2024

We intent to go to market with a request for proposals for non-network solutions.

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

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[23].

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.

[23] Refer to System Security Forecast from Transpower.

5.10.4 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 by the Department of Conservation administers Mount Cook Village. Fairlie is a farming support town, while Tekapo and Mount Cook Village are tourist and holiday home destinations with growing subdivision and hotel accommodation developments.

Genesis Energy has generation assets at Lake Tekapo and Lake Pukaki. There is growth in the Tekapo area, with plans for further irrigation development in the Mackenzie Basin, and new retail developments and subdivisions in the Tekapo township.

Network configuration

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

5.10.4.1 DEMAND FORECAST

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

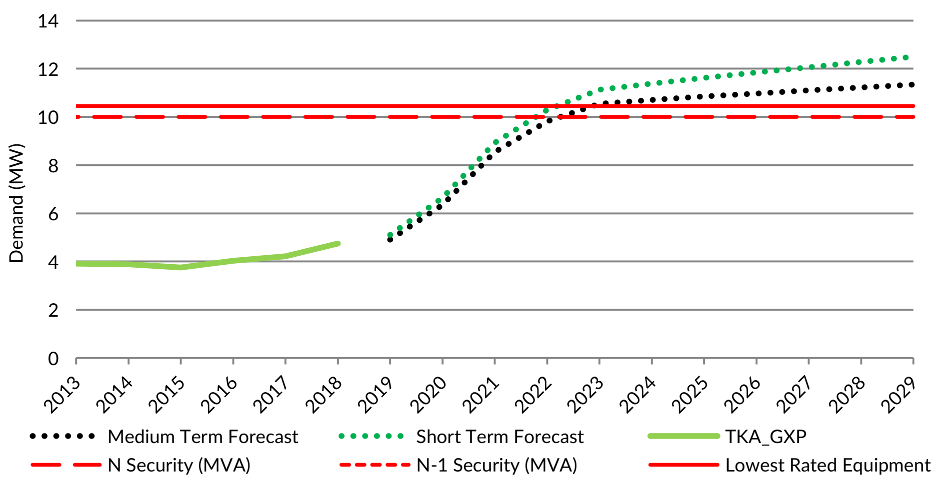


Figure 5.21 Tekapo GXP demand forecast

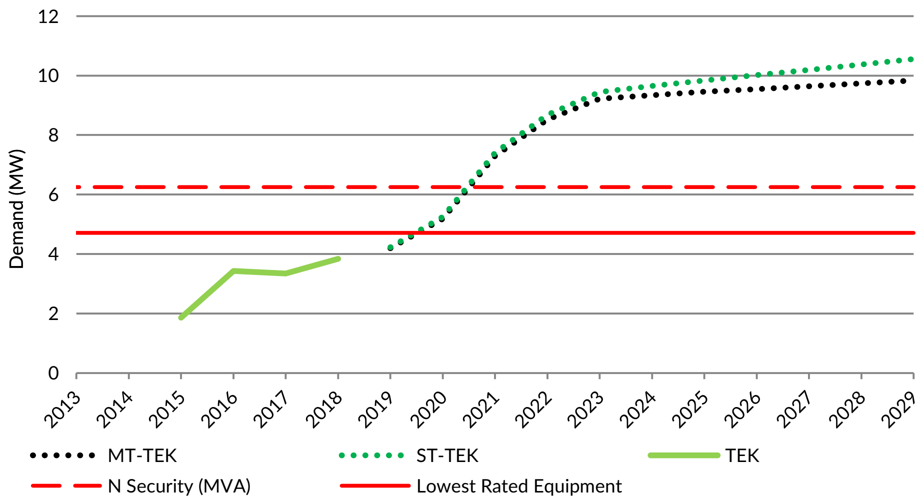


Figure 5.22 Tekapo zone substation demand forecast

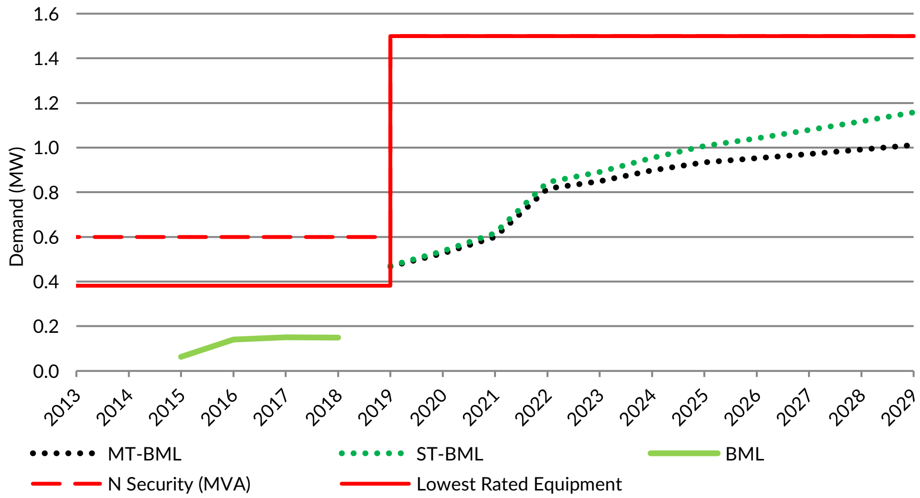


Figure 5.23 Balmoral zone substation demand forecast

Table 5.10 Tekapo region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)
Tekapo GXP	10.00	-	10.46	5.02	6.40	8.59	9.86
Tekapo zone substation	6.25	-	5.18	4.30	5.23	7.34	8.56
Haldon-Lily Bank zone substation	1.00	-	1.00	0.50	0.50	0.51	0.51
Balmoral zone substation	0.60	-	0.38	0.57	0.70	0.77	0.99
Unwin Hut zone substation	1.50	-	2.86	0.87	0.87	0.88	0.88

5.10.4.2 SECURITY OF SUPPLY

Table 5.11 Tekapo, Mt Cook, Glentanner security of supply

Zone sub/load centre	Actual security level	Target security level	Configuration and options
Tekapo CBD	N-0.5	N-1 (switched)	No alternate supply to zone substation. The mobile substation and the mobile generator can be connected at the TEK zone substation. Some load can be supplied by adjacent 11 kV feeders.
Mt Cook and Glentanner	N	N	No alternate 33 kV supply to Unwin Hut zone substation. Mobile substation can be connected at Unwin Hut zone substation to supply Mt Cook.
Tekapo rural	N	N	Radial lines, little backup. Generator port on 11 kV at Haldon-Lilybank.

5.10.4.3 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 it's demand.

The increasing demand leads to increased load on the feeders into the township. Because these feeders also continue through the township into the rural area east of the township, they are becoming voltage constrained. With no voltage control capability at the Haldon-Lilybank zone substations, network investment will be required when voltage constraints develop. The Balmoral zone substation will be replaced in 2019. Voltage regulation functionality forms part of the new substation.

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.

5.10.4.4 MATERIAL GROWTH AND SECURITY PROJECTS

This section is a summary of material projects planned for the Tekapo region.

Tekapo zone substation power transformer upgrade

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

As shown from the demand forecast plot (Figure 5.22), demand is expected to reach the transformer rated capacity of 6.25 MVA 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.

TKA GXP step-up transformer upgrade

Estimated cost (concept)	TBC
Expected project timing	2019-2020

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.

Tekapo zone substation - Increase transformer security of supply from N to N-1

Estimated cost (concept)	Approximately $3 M
Expected project timing	2023

When the transformer at the Tekapo zone substation is upgraded, our security of supply standard may require N-1 security. This requires a second transformer. There are several options to consider, the options being a second transformer at the existing zone substation and the second being a new zone substation at a different location. A detailed engineering study of the options will be required to establish the best option.

Additional feeder(s) into the urban area of Tekapo

Estimated cost (concept)	TBC
Expected project timing	2019-2021

The existing 11 kV feeders into the Tekapo township will become constrained in the near future. To increase capacity, an additional feeder is required. This work will coincide with the undergrounding of the backbone of the existing feeders and a switching reconfiguration in the CBD.

The cost for this is difficult to determine due to the fact that the project driver will be commercial development and subdivisions. Because of this, portions will be funded through capital contributions by the developers.

Ripple injection plant replacement	
Estimated cost (concept)	$400 k
Expected project timing	2024
Replace 500 Hz rotating plant. Consider smart metering functionality.	

Upgrade the Simons Pass 11 kV feeder backbone.	
Estimated cost (concept)	$355 k
Expected project timing	2020-2021
To supply the proposed irrigation and dairy conversions load increase in Simons Pass, the first section of the 11 kV feeder (from the Tekapo zone substation to the army camp) requires a conductor upgrade.	

5.10.5 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 consumer, 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.

5.10.5.1 DEMAND FORECAST

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

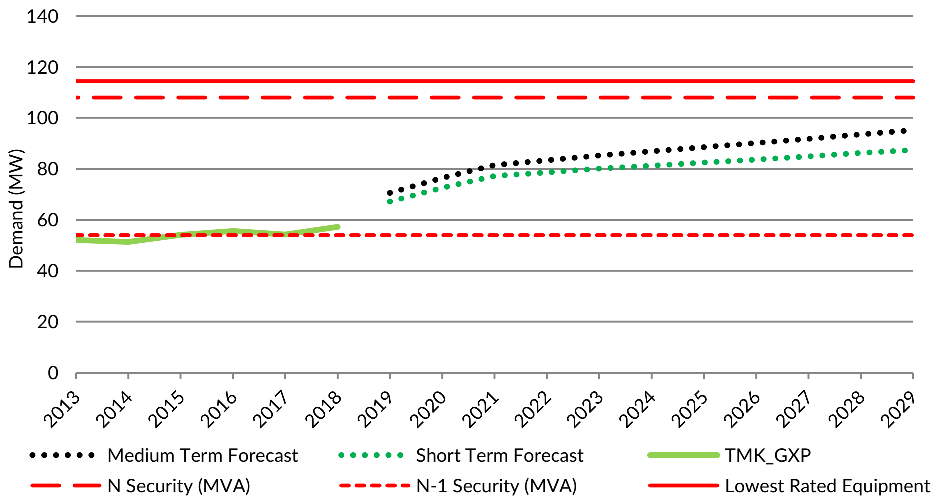


Figure 5.24 Temuka GXP demand forecast

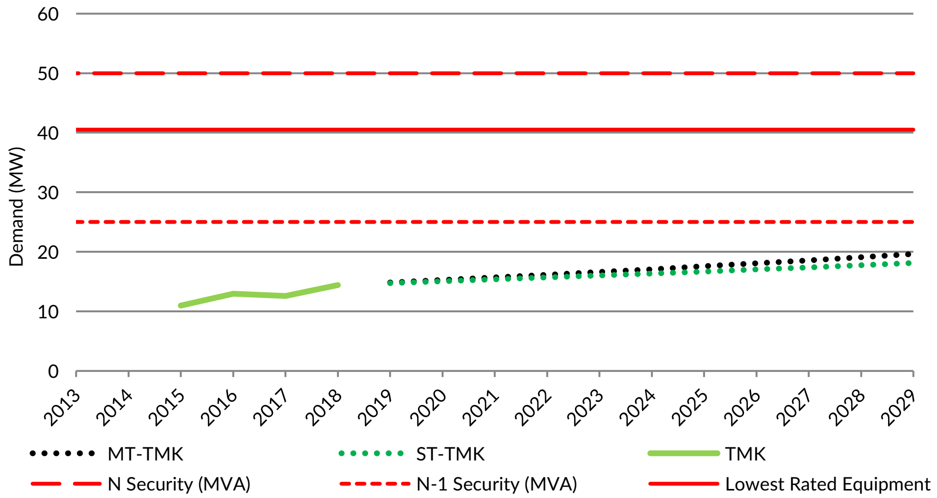


Figure 5.25 Temuka zone substation demand forecast

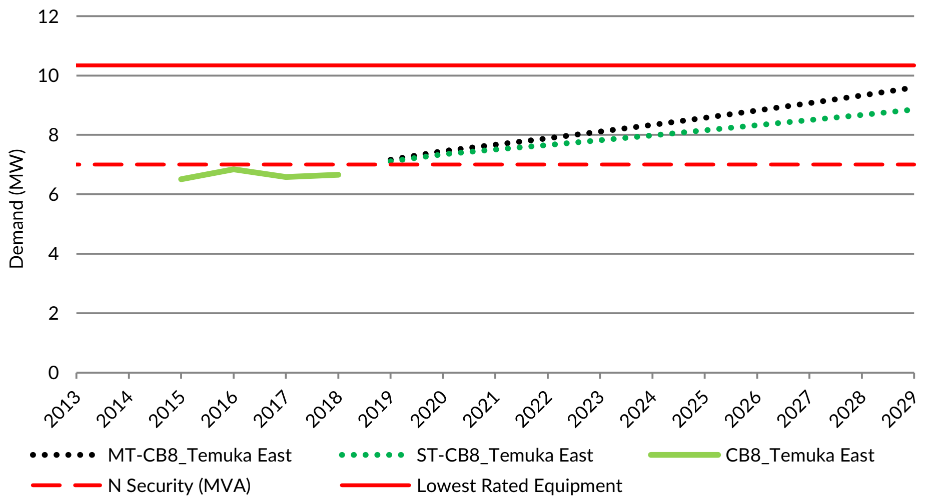


Figure 5.26 Geraldine zone substation demand forecast

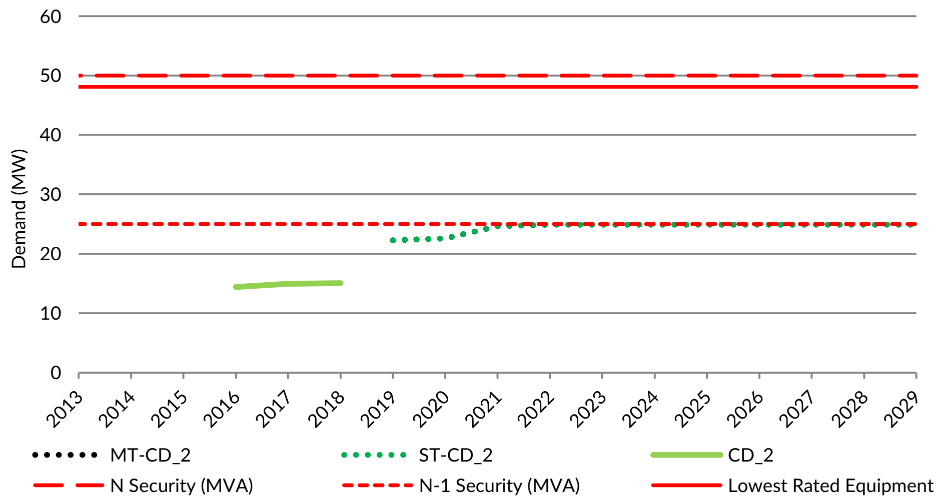


Figure 5.28 Clandeboye 2 zone substation demand forecast

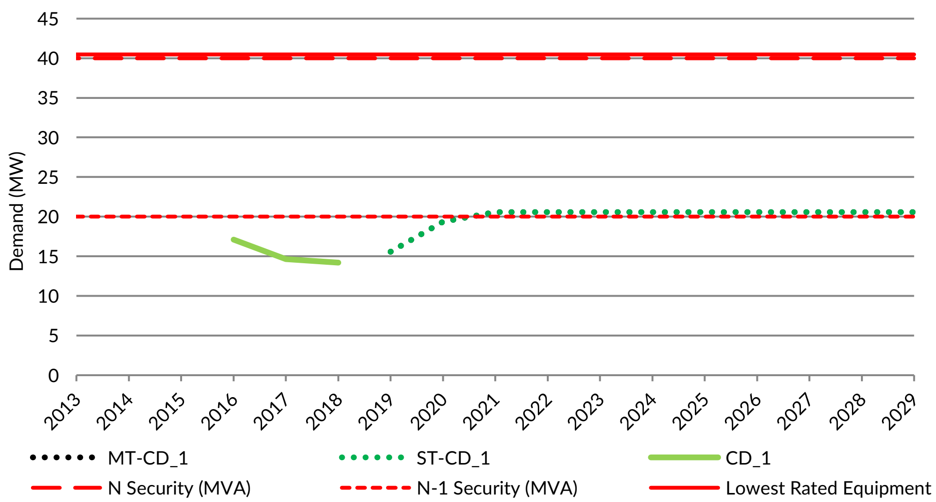


Figure 5.27 Clandeboye 1 zone substation demand forecast

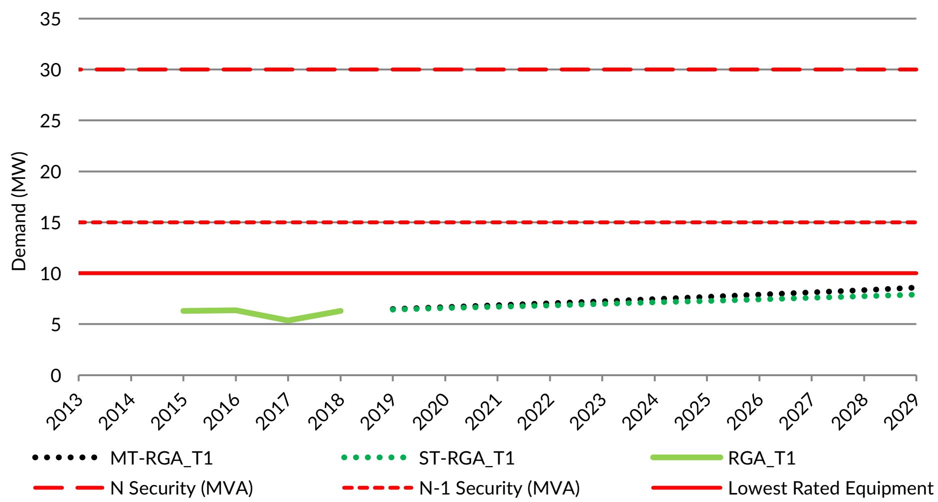


Figure 5.29 Rangitata 1 zone substation demand forecast

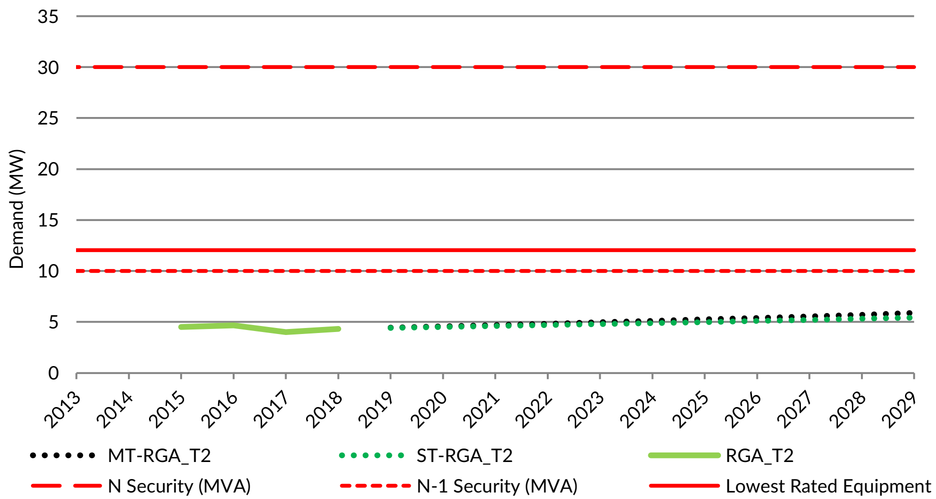


Figure 5.30 Rangitata 2 zone substation demand forecast

Table 5.12 Temuka region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)
Temuka GXP	108.00	54.00	93.36	70.55	76.43	81.43	83.06
Temuka zone substation	50.00	25.00	40.50	14.84	15.26	15.69	16.14
Geraldine zone substation	7.00	-	10.34	7.16	7.46	7.67	7.89
Rangitata 1 zone substation	30.00	15.00	10.00	6.48	6.67	6.86	7.05
Rangitata 2zone substation	30.00	10.00	12.46	4.44	4.57	4.70	4.83
Clandeboye #1 zone substation	40.00	20.00	40.46	15.57	19.37	20.57	20.57
Clandeboye #2 zone substation	50.00	25.00	48.11	22.26	22.61	24.65	24.65

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 to upgrade the Temuka GXP.

5.10.5.2 SECURITY OF SUPPLY

Table 5.13 Temuka, Geraldine, Rangitata and Clandeboye security of supply

Zone sub/load centre	Actual	Target	Configuration and options
Temuka residential	N-1	N-1 (switched)	Some load can be supplied by adjacent 11 kV feeders and 400 V reticulation.
Temuka rural	N-0.5	N	Some load can be supplied by 11 kV feeders from Geraldine, Rangitata, Pleasant Point, and Timaru zone substations.
Clandeboye CD1 and CD2	N-1 for 33 kV subtransmission circuits and zone substations.	N-1	load can be supplied by adjacent 11 kV feeders on the Fonterra dairy factory site.
Rangitata	N-1 for 33 kV circuits and zone substation transformers.	N	N-1 for 33 kV circuits only as long as the load is less than 10 MW. Some load can be supplied by 11 kV feeders from Geraldine and Temuka zone substations.
Geraldine	N-0.5	N-0.5	Some load can be supplied by 11 kV feeders from Pleasant point and Rangitata zone substations. Mobile substation can be connected at the Geraldine zone substation.

5.10.5.3 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 underway 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[24].

24The Electricity Industry Participation Code from the Electricity Authority is a mandated code under the Electricity Industry Act 2010.

5.10.5.4 MATERIAL GROWTH AND SECURITY PROJECTS

This section is a summary of material growth projects planned for the Temuka region.

Temuka GXP upgrade

Estimated cost (concept)	$400 k
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. This work is dependent on Fonterra's requirements for additional capacity. Both these projects are Transpower owned and as such are financed through the transmission charges regime.

As a result of this project we will have to make alterations to our assets to connect to the new switchboard.

Geraldine transformer replacement

Estimated cost (concept)	$2 M
Expected project timing	2020

Load growth indicates that this transformer may need upgrading by 2019/20 (based on 7 MVA transformer capacity).

In addition, the existing transformer is at the end of its life. The present insulation condition has a high probability of the transformer failing.

Until the new transformer is commissioned, our mobile substation can be deployed at the Geraldine zone substation.

CD1 zone substation upgrade/replacement/relocation

Estimated cost (concept)	$3.2 M
Expected project timing	T+3 years

CD1, the oldest of the two zone substations supplying the Fonterra Clandeboye dairy factory, will lose N-1 security in 2021. The existing substation has a limited footprint available, due to factory plant encroaching on it.

This may force the relocation or establishing a third zone substation in a different location.

The options need to be discussed with the consumer and timing depends on the Fonterra objectives.

CD2 zone substation upgrade

Estimated cost (concept)	TBC
Expected project timing	T+2 years

CD2 zone substation will lose N-1 security in 2022.

The options need to be discussed with the consumer and timing depends on the Fonterra objectives.

Geraldine township 11 kV feeder

Estimated cost (concept)	$265 k
Expected project timing	2020

The Geraldine township feeder will run out of capacity in 2025. The 11 kV feeder will require an upgrade, or an additional feeder to be installed.

5.10.6 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[25] 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.

5.10.6.1 NETWORK CONFIGURATION

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

5.10.6.2 DEMAND FORECAST

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

Figure 5.31 Timaru GXP demand forecast

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

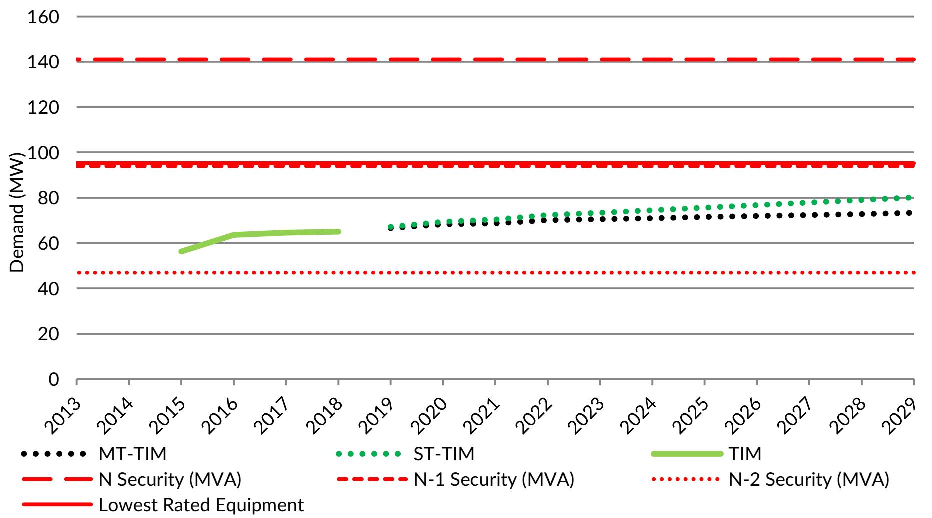


Figure 5.32 Timaru zone substation demand forecast

Figure 5.34 Timaru 11/33 kV zone substation T2 demand forecast

Figure 5.33 Timaru 11/33 kV zone substation T1 demand forecast

Figure 5.35 Pareora zone substation demand forecast

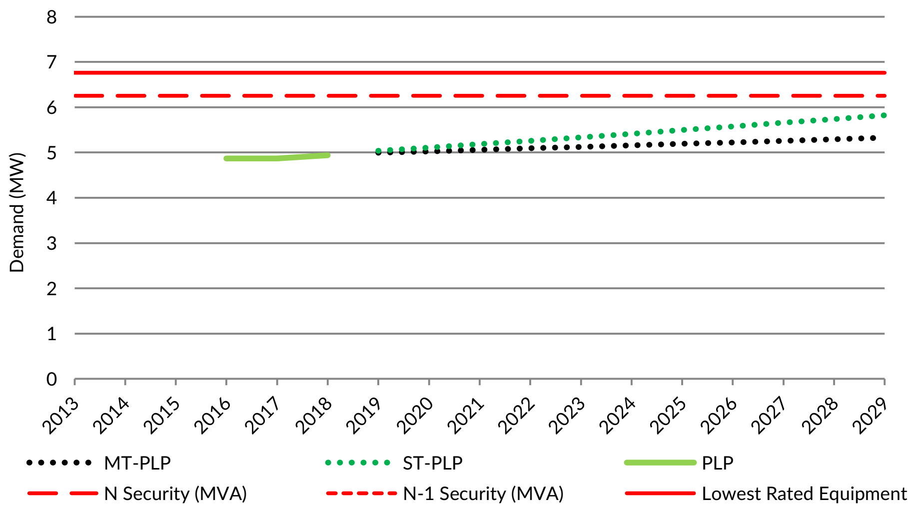


Figure 5.36 Pleasant Point zone substation demand forecast

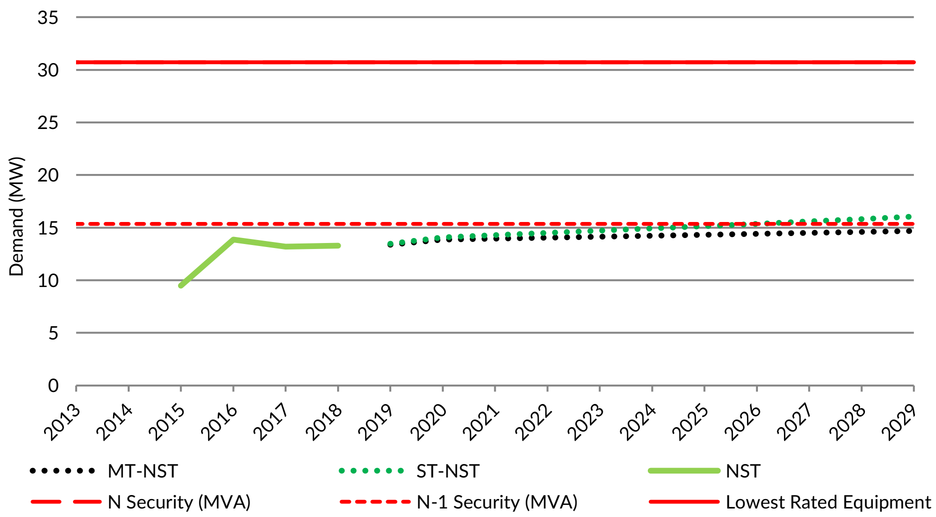


Figure 5.38 North Street switching station demand forecast

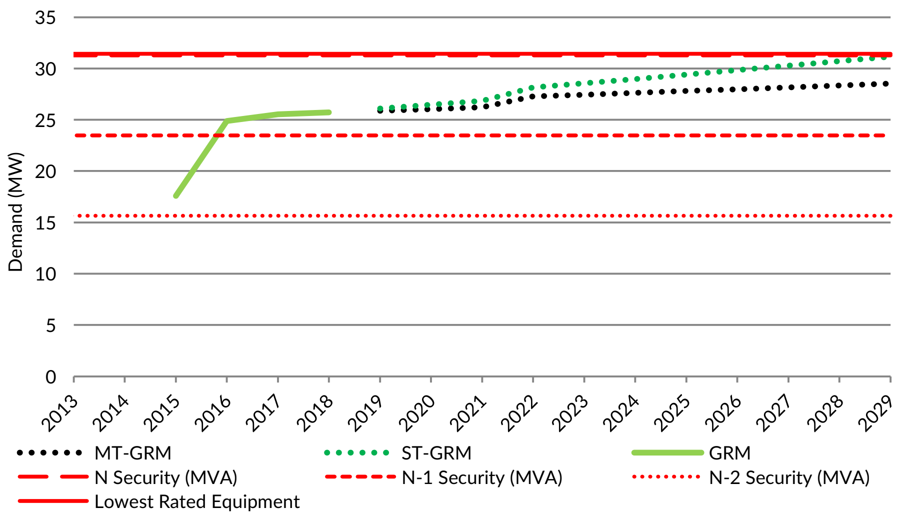


Figure 5.37 Grassmere switching station demand forecast

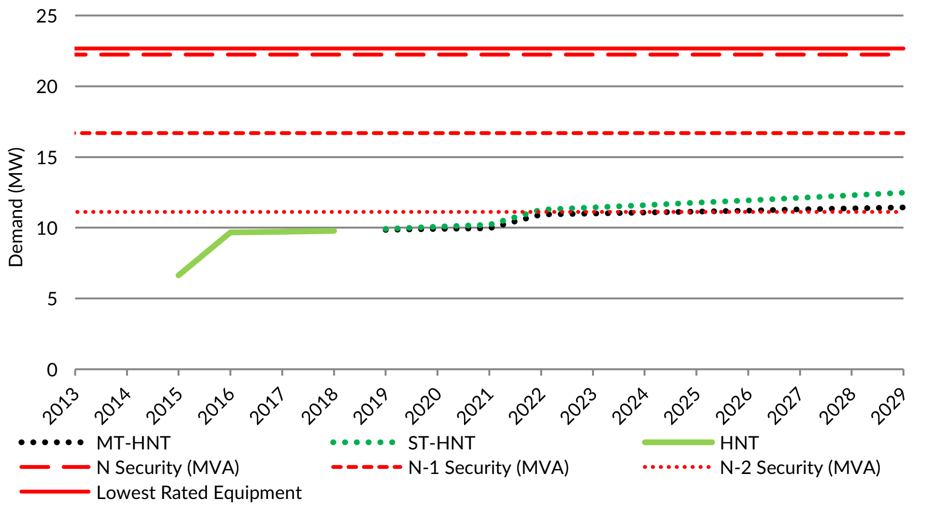


Figure 5.39 Hunt Street switching station demand forecast

Table 5.14 Timaru region demand forecasts

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)
Timaru GXP	141.00	94.00	93.81	69.02	70.71	71.14	71.58
Timaru zone substation	141.00	94.00	93.81	68.90	70.60	71.05	71.51
Alpine Timaru Step-up (ATM)	50.0	25.00	13.72	6.43	6.48	6.52	6.56
Alpine Timaru Step-up (ATM_2)	50.0	25.00	13.72	10.93	11.00	11.07	11.15
Pleasant Point zon substation	6.25	-	14.63	5.00	5.03	5.06	5.09
Pareora zone substation	30.00	15.00	21.61	8.81	8.87	8.93	8.98
Grasmere switching substation	31.29	23.46	31.44	28.13	28.31	28.50	28.68
North Street switching substation	30.89	15.44	30.72	13.37	13.86	13.95	14.04
Hunt Street switching substation	22.46	16.85	22.67	10.75	10.81	10.88	10.95

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 metres to be a permitted activity. This has been done through the District Plan review process and their Growth Management Strategy consultation.

5.10.6.3 SECURITY OF SUPPLY

The security of supply for Timaru, Pareora and Pleasant Point zone substations are detailed in Table 5.15.

Table 5.15 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 an outage to that bus, until a tie is made to the remaining 33 kV bus.
Timaru residential	N-1 (switched)	N-1 (switched)	There is extensive inter-connectivity on the feeders from Timaru, Grassmere, North Street and Hunter street zone substations.
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.
Washdyke/ Seadown	N-1 (switched)	N-1 (switched)	Four new 33 kV cable circuits from Seadown to Timaru to run at 11 kV was installed in 2017.
Timaru CBD (Grassmere, Hunt Street, and North Street)	N-1 (switched)	N-1 (switched)	There is inter-connectivity on the 11 kV feeders and 400 V reticulation.
Redruth area	N-1 (switched)	N-1 (switched)	There is inter-connectivity on the 11 kV feeders and 400 V reticulation
Port area	N-1 (switched)	N-1 (switched)	There is inter-connectivity on the 11 kV feeders and 400 V reticulation
Pareora 33/11°kV zone substation	N-1 for transformers, 10 MVA for sub-transmission circuits	N-1 for transformers	Some load can be supplied using 11 kV feeders from Studholme and Timaru in an emergency.

Zone sub/load centre	Actual security level	Target security level	Configuration and options
Pleasant Point 33/11 kV zone substation	N-0.5	N	Some load can be supplied using 11 kV feeders from Pleasant Point t, Temuka and Timaru zone substations in an emergency.

5.10.6.4 EXISTING & FORECAST CONSTRAINTS

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 restore supply.
- There are areas of supply at the boundary of the historical areas that can be improved by greater integration of the assets of the two legacy networks (e.g. by upgrading 11 kV lines and cables, and introducing additional, or upgraded, points of connection between the two networks).

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.

5.10.6.5 MATERIAL GROWTH AND SECURITY PROJECTS

This section is a summary of material growth projects planned for the Timaru region.

Western Timaru 11 kV distribution feeder relocation

Estimated cost (concept)	$1.1 M
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 Highfield feeder relocation is one example of this work.

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

Timaru 33 kV Zone Substation (ATM) switchgear replacement

Estimated cost (concept)	$3.8 M
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.

Consideration will be given to any future proofing in case the North street switching station will be upgraded to a zone substation.

Pleasant Point transformer replacement

Estimated cost (concept)	$2.2 M
Expected project timing	2024

The existing transformer is forecast to reach its capacity in 2024 and will require upgrading or non-network solutions.

5.10.7 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.

5.10.7.1 DEMAND FORECAST

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

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.

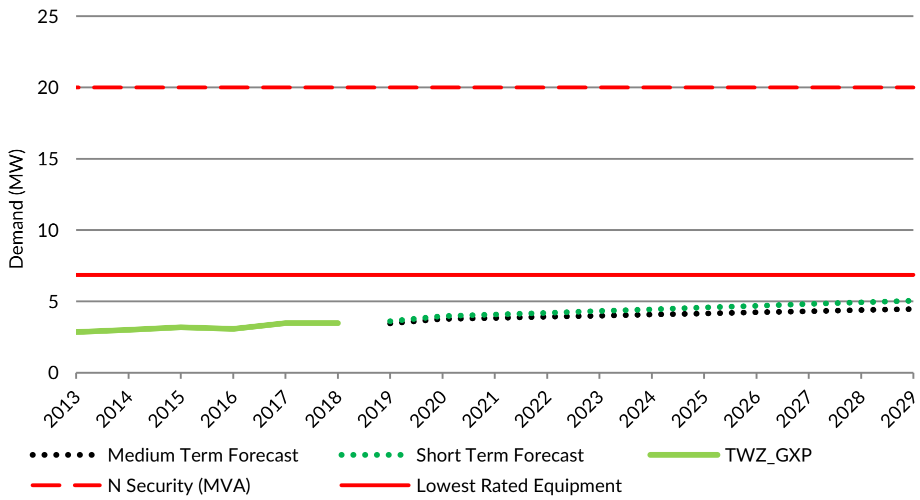


Figure 5.40 Twizel GXP demand forecast

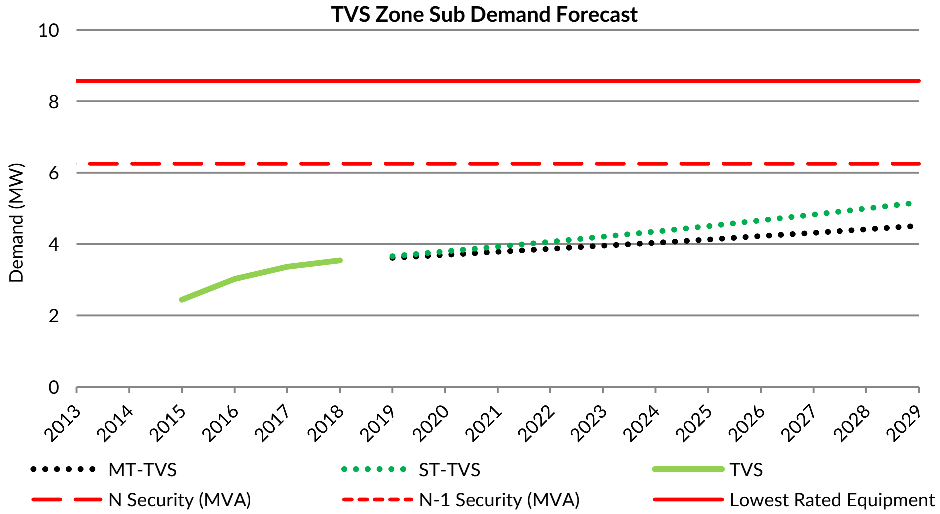


Figure 5.41 Twizel Village zone substation demand forecast

Table 5.16 Twizel region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)
Twizel GXP	20.00	-	6.86	3.45	3.76	3.83	3.91
Twizel Village zone substation	6.25	-	6.25	3.61	3.70	3.78	3.86

5.10.7.2 SECURITY OF SUPPLY

The current security of supply for Twizel is given in the table below.

Table 5.17 Twizel region security of supply

Zone sub/load centre	Actual security level	Target security level	Configurations and options
Twizel residential	N-0.5	N-0.5	There is a 3 MVA spare 33/11 kV transformer located at TVS zone substation.
Twizel rural	N	N	None.

5.10.7.3 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.

5.10.7.4 MATERIAL GROWTH AND SECURITY PROJECTS

This section is a summary of material projects planned for the Twizel region.

Twizel zone substation (TVS) asset replacements

Estimated cost (concept)	$3.15m
Expected project timing	2021-2023

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.

Transpower outdoor to indoor conversion of the GXP 33KV switchgear

Estimated cost (concept)	TBC
Expected project timing	2020-2021

There is an opportunity to request an additional 33 kV circuit breaker as part of the Transpower project.

This additional circuit breaker can provide N-1 supply to the TVS or supply a new 33/11 kV zone substation.

This option will be considered together with the TVS replacement options.

OUR ASSET FLEETS

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.

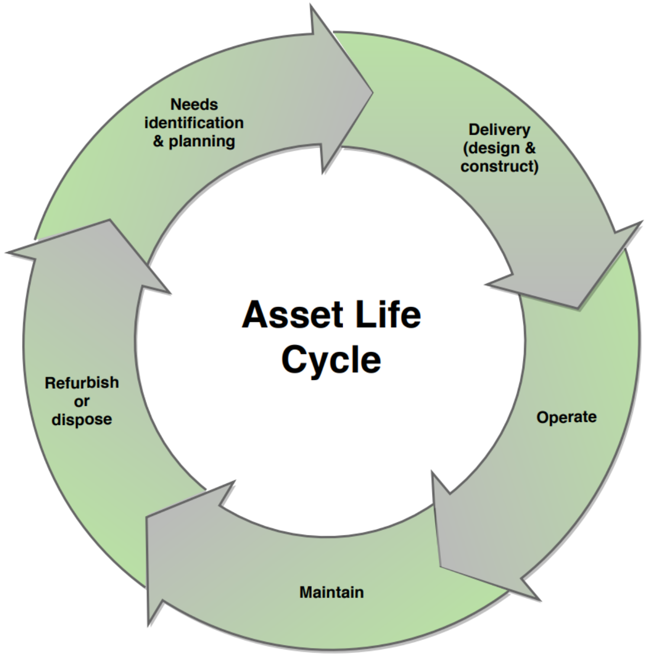


Figure 6.1 Asset management life cycle

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

- Needs identification and planning
- Delivery (design and construct)
- Operating
- Maintaining
- 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 section 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 control is to ensure a continuous supply of electricity to our consumers 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 to make available sections of the network for maintenance or repairs by contractors. In addition, they also manage controllable load on our network to comply with retailer contracts with consumers, and to manage peak loading on our network. We manage both the HV and LV networks through our Control Centre.

The Control Centre also performs the dispatch function, communicating with consumers 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, loading and performance. This includes the loading, currents and voltages 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.

The SCADA system is also used to perform load control functions and to operate circuit breakers and switches across the network remotely. 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 increased use of automation and real-time monitoring.

Our SCADA system is continually developed and maintained by our 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 consumers. They also manage outage restoration efforts including tracking interruptions to consumers, 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 and integrated with our GIS, 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 consumers.

6.1.2 SWITCHING

Switching is carried out to disconnect sections of the network for safety isolation to enable maintenance work or new connection work to be undertaken, or to restore supply in the event of a network fault. We can switch devices that have been automated remotely from the control room while all other devices are switched manually on site. All our major zone substations are remote controllable 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:

- Remote controlling of more field devices to improve operational responsiveness. These include more reclosers, remote control voltage regulation devices and remote telemetry 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 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 planning for SIE work other than ensuring there are sufficient resources on standby to respond to network faults. This is achieved through a specified agreement with NETcon. Failure to respond to SIE promptly, adversely affects the service provided to our consumers and may pose risks to public safety.

We require our service provider to maintain 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 consumers 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.

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 consumers 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.

- **Health & Safety culture** – hold regular health & 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 consumers 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. This category of expenditure includes a contracted service for first response fault calls. In essence, this represents eight full-time field switchers that serve on a standby and on-call roster. Where costs relate to operating for capital projects, the costs are counted against the project and consequently removed from the SIE expenditure category.

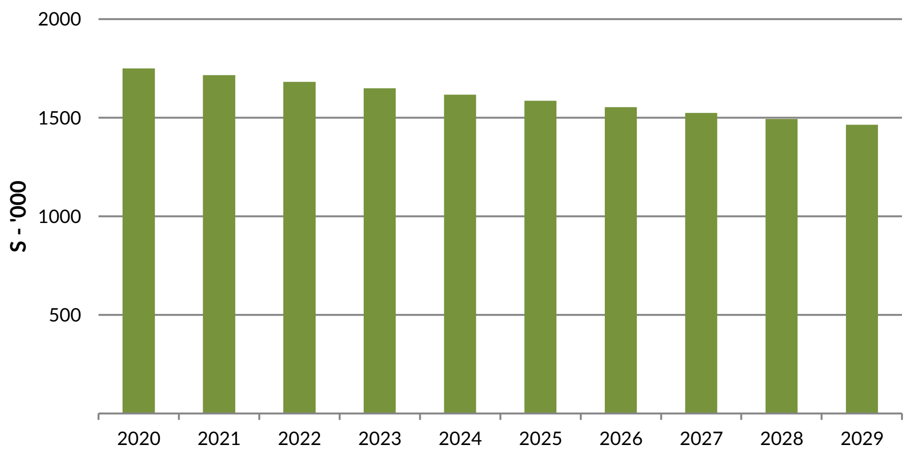


Figure 6.2 Forecast expenditure on SIE

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 safely and reliably 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, consumers, regulators, and other stakeholders (such as the communities in which we operate).

We undertake network maintenance as:

- routine maintenance
- maintenance projects
- vegetation maintenance[26]

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.

The four work types are summarised below.

[26] Refer to section 6.1.5 for more detail.

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 can 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 thermo-graphic 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 address 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 an 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 detailed planning of Network and land access, resources and work scope for each job, all supporting execution of the work.

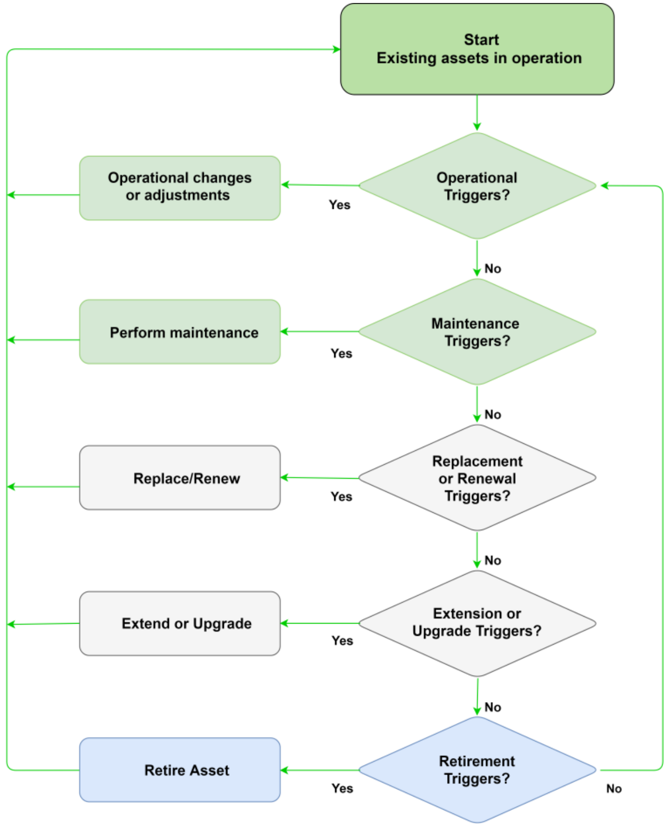


Figure 6.3 Maintenance life cycle

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).

Table 6.2 Asset replacement and 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 consumers 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 promptly 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 (see figure below).

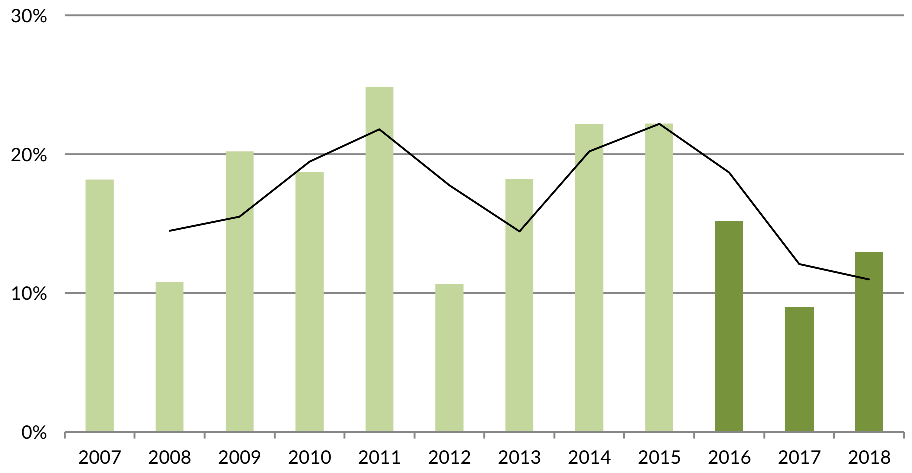


Figure 6.4 Percentage of vegetation related interruptions

Since 2016 we have emphasised on vegetation management to help reduce unplanned outages by employing an in-house vegetation coordinator and increasing our vegetation opex budget in 2016 and again in 2019. 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

Asset management objective	Portfolio objective
	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 consumer 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 .

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 effort and build on the momentum we have achieved to date.

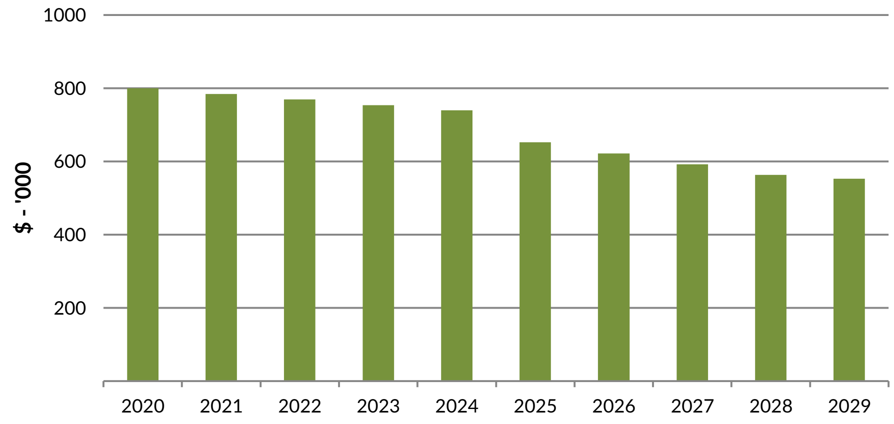


Figure 6.5 Vegetation management opex

We have recognised that our risk profile in relation to tree encroachment near our lines is higher than we would like. To reduce this and achieve our objectives of improved reliability performance will require additional effort and increase in expenditure. In this regard we have again increased our budget for vegetation management from $600 k per annum to $800 k per annum for the 2019-2023 period. We expect that once we get on top of this issue expenditure will reduce.

6.2 OVERHEAD STRUCTURES

6.2.1 OVERVIEW

This section 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[27] 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 and conductor for the planning period is forecast at $45.4 M over the planning period. This portfolio accounts for 53% 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.

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.

Figure 6.6 Wood pole left and concrete pole right.

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.

[27] Asset age data is given as at 31 March 2018. New assets installed or planned for the current financial year is specified in the text of each asset type section.

Asset management objective	Portfolio objective
Cost	Provide cost effective designs, construction, operational and disposal techniques for all structures and lines.
Community	Minimise planned outages to consumers 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. The majority of the 33 kV sub-transmission network was installed in the 1960s and 1980s to meet the growing demand from the rural network. The growth spike of 1996 was due to the construction of the 30 MVA dairy factory at Clandeboye. In 2004, a new line was constructed to supply RGA substation. In 2013, a new double circuit 110 kV designed line, energised at 33 kV, was constructed to supply the ODL dairy factory at Glenavy.

Table 6.5 Number and estimated life of pole types

Type	Number	% of total	Estimated life (years)	Average age
Hardwood	13,983	34%	40-60	35
Softwood	5,332	12%	25-50	24
Concrete	22,299	54%	60-100	36

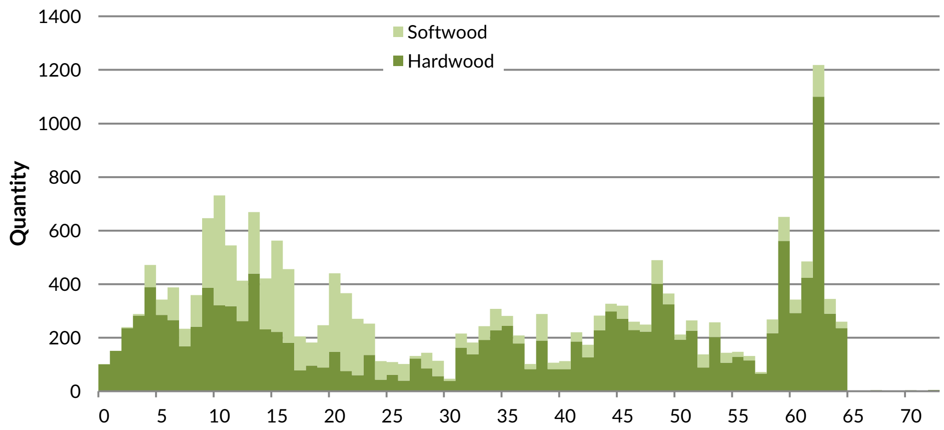


Figure 6.7 Wood pole age profile in years.

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 concrete poles, are more than 35 years old.

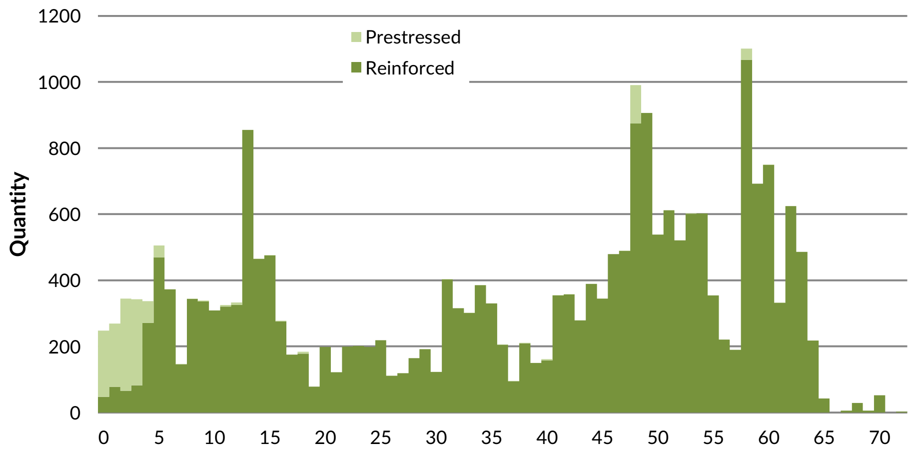


Figure 6.8 Concrete pole age profile in years.

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.

6.2.4 CONDITION, PERFORMANCE AND RISKS

We have developed asset health indicators (AHI) that reflect the remaining life of an asset based on the Electricity Engineers' Association (EEA) *Asset Health Indicator Guide, 2016*. In essence, our AHI models predict an asset's 'end-of-life' and categorise their health based on the guide's recommendations for end of life based on age. Where actual asset condition and historical data is available, the EEA guide numbers have been adjusted.

The aged based asset health profile for our pole fleet is shown in Figure 6.9.

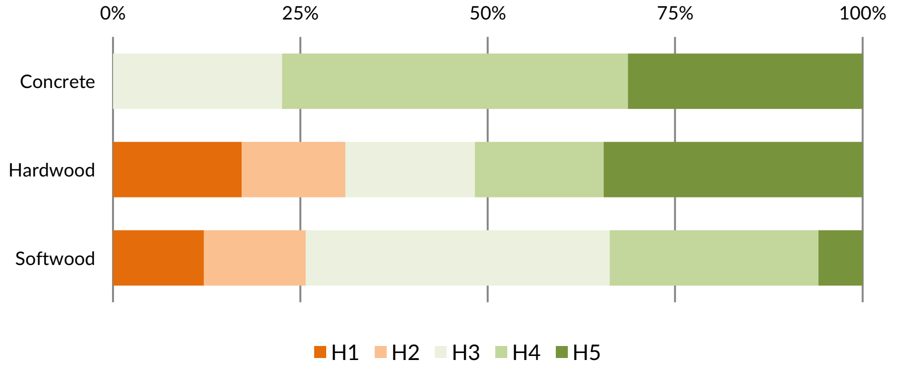


Figure 6.9 Pole structure asset health as at 2018

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, 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 spreadsheets, 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.

Existing overhead infrastructure will only be undergrounded if:

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

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

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 Limited, our fully owned contracting company, carries out the majority of our overhead line work to ensure consistent construction methods and standards.

33 kV sub-transmission lines are a high priority due to their potential impact on network reliability. Sub-transmission 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.

The open ring system is used for underground cable systems where fault repair time is much longer than for an overhead system. The probability and extent of an underground system fault is much lower than for an overhead system as overhead lines are exposed to risk from severe weather, bird and vegetation interference, and vehicle damage. The risk to underground cables is from inadvertent damage from contractor excavations and low probability severe earthquakes.

Historically, in the days of dry farming and cropping, lightly loaded rural areas were arranged as a single spur overhead line. With load density growing markedly due to dairying and irrigation, rural lines are built or upgraded to be open-ringed, providing alternative supply routes 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 ten 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 ten 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 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 sub-transmission 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 assess the condition of these over ten years requires 3,000 to be assessed annually. Assessments 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 the 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 firewood 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 13 mm^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.

The circuit kilometres of all overhead network lines constructed, by voltage level, three-phase, single-phase, and single wire earth return (SWER), are shown in Table 6.6.

Table 6.6 Overhead circuit length in km

Voltage	3-phase	1-phase
110 kV	24	N/A
33 kV	227	N/A
22 kV	28	116
11 kV	1937	837
400 V	285	75

Not all conductors perform uniformly, with some single strand (LV) 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. However, this 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.

Portfolio summary

Investment in overhead conductor for the planning period is rolled into the overhead 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 6.7 below.

Table 6.7 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

Asset management objective	Portfolio objective
	mechanical strength in conductor choice.
Community	Minimise planned outages to consumers 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 reliable overhead network.

6.3.3 POPULATION AND AGE STATISTICS

Figure 6.10 details the overhead conductor length at a subtransmission level for the types of conductor that we use. All our AAAC conductor is less than ten years old with a minimal amount of copper still used at subtransmission level.

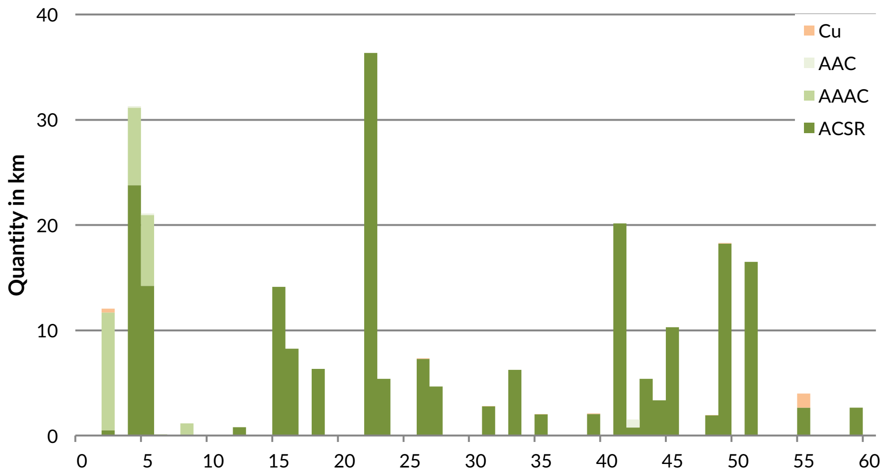


Figure 6.10 Subtransmission conductor age profile in years.

The majority of copper conductor that is 56 years old will be replaced as part of undergrounding one of the Pareora 33 kV subtransmission feeders in 2019.

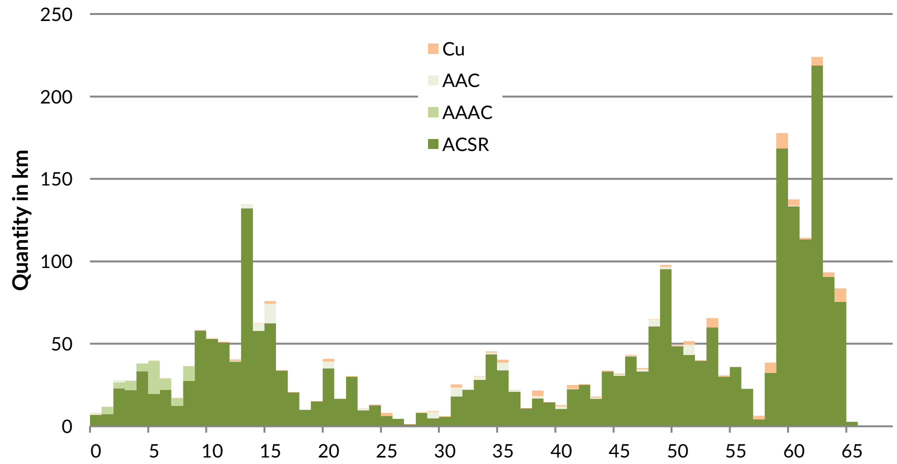


Figure 6.11 Distribution conductor age profile in years.

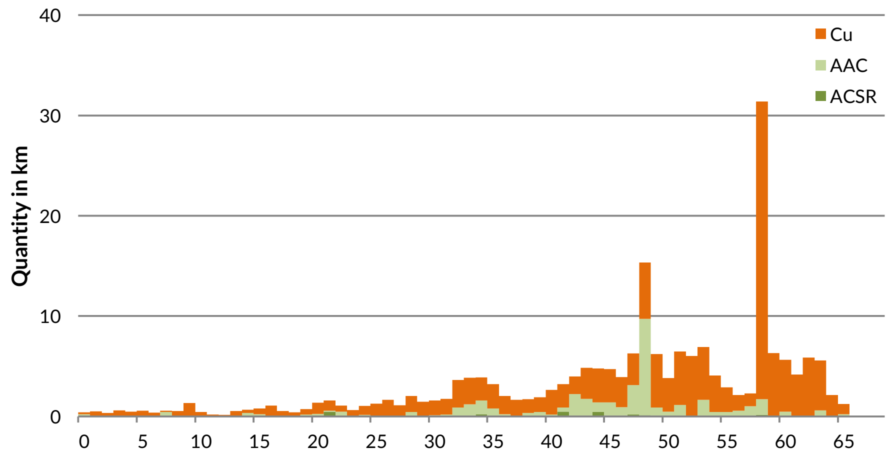


Figure 6.12 Low voltage conductor age profile in years.

ACSR conductor makes up most of our distribution overhead lines and consists mainly of Herring, Gopher, Magpie and Mink types. On average we replace and renew our overhead line infrastructure at a rate of 5% per annum per. Figure 6.11 depicts our distribution conductor by type, age and quantity.

The majority of our low voltage overhead networks are in urban areas and are constructed in copper conductor.

Table 6.8 Overhead conductor type length and percentage of total

Type	Length (km)	% of total
AAAC	86	2.45%
AAC	107	3.04%
ACSR	2764	78.61%
Cu	242	6.88%
*other	318	9.05%

* 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[28] over its lifetime however this has proven to not have been damaging. The aged based[29] asset health profile for overhead conductors are shown in Figure 6.13.

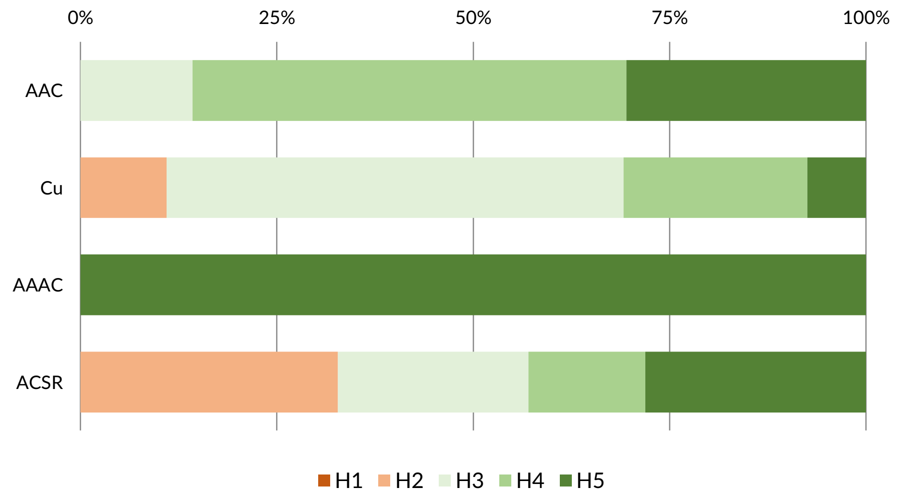


Figure 6.13 Overhead conductor asset health as at 2018

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

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

[29] In accordance with the EEA Asset Health Indicator Guide.

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 been recently approved for 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 ten year cyclic programme. Intrusive inspections are performed, through conductor sampling, only when required such as 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 clash.

6.3.7 RENEW OR DISPOSE

The dairy and irrigation industry has driven the 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 ten 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 section describes our underground cables portfolio and summarises our associated fleet management plan. The portfolio includes three fleets:

- Subtransmission cables
- Distribution cables
- LV cables

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.

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 namely 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 and wrapped in tar impregnated fibre material, PVC, or polyethylene. PILC cables have a good performance record in the industry.

The first XLPE cables were installed in the Alpine area after the mid-1970s. Consequently our XLPE cables are of the more 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 1kV (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.

Consumer 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 $ 16.9 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 12% of the total expenditure over the planning period.

6.4.2 UNDERGROUND CABLE PORTFOLIO OBJECTIVES

Table 6.9 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 IPENZ.

6.4.3 POPULATION AND AGE STATISTICS

Our network contains over 780 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.

Table 6.10 Underground cable circuit lengths

Voltage	Length (km)	% of total
33 kV	29.6	3.78%
22 kV	4.8	0.61%
11 kV	398	50.9%
6.6 kV	7.25	0.93%
400 V	343	43.8%

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 60 years for those installed afterwards. The difference is due to advances in XLPE materials and construction made in 1986 that led to XLPE cables having a significantly longer service life. It should be noted that our lifespan assumptions[30] 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.

[30] For modern XLPE cables.

All 33 kV cables on our network are less than 40 years old and are all of XLPE type. The age profile of our subtransmission cables is shown in Figure 6.14.

The majority of our subtransmission cable that is 13 years old are the two cable circuits between the Temuka GXP and our Clandeboye substations supplying Fonterra. We have an additional 24 km of 33 kV cables that is currently operating at 11 kV. This higher rated cable was installed to allow a future upgrade in operating voltage when the load requires.

The cables 35 years and older mainly constitutes the Timaru to Pareora substation circuit no. 1 subtransmission cable. The most recent condition assessment reports record these cables to be in a good condition, and consequently, their replacement is not included in this planning period.

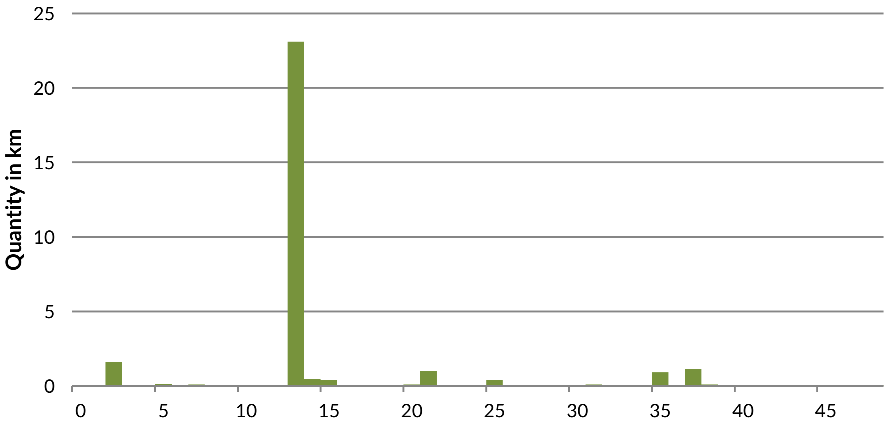


Figure 6.14 Sub-transmission cable age profile in years.

There is a cable that is 48 years old which connects the Twizel ripple plant to our network. This cable is not used since Network Waitaki has full use of the ripple plant at the Twizel GXP.

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 per cent 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 70-100 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 60 years.

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

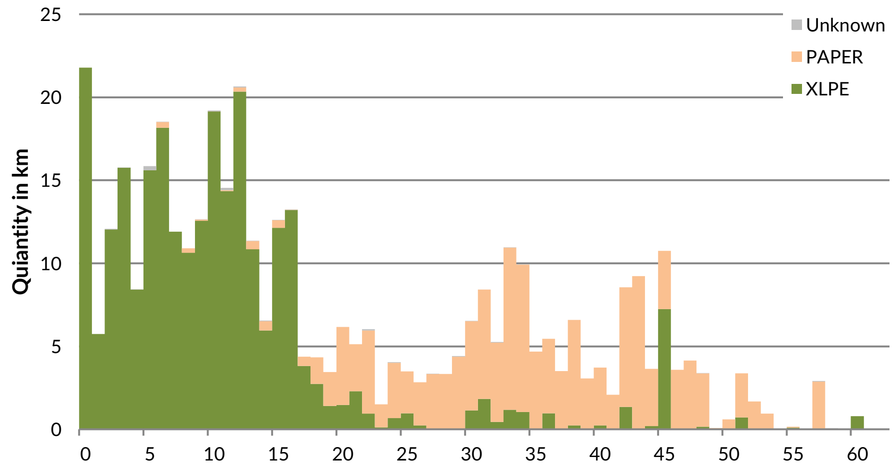


Figure 6.15 Distribution cable age profile

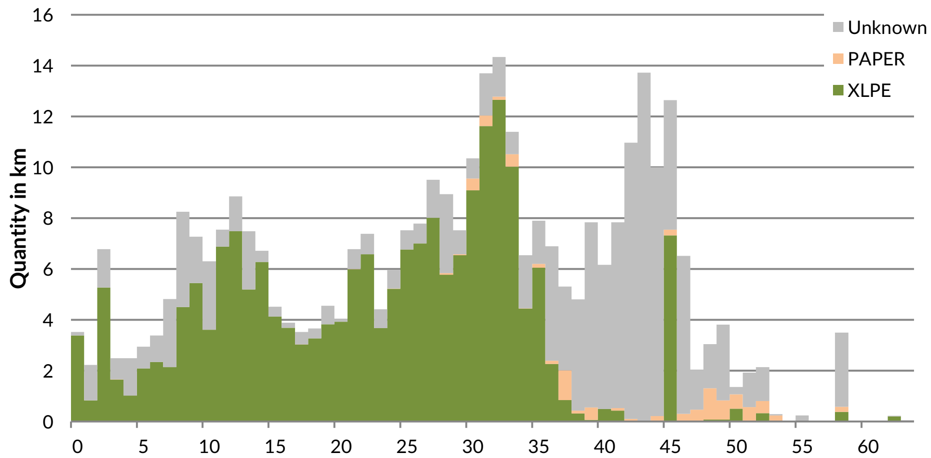


Figure 6.16 Low voltage cable age profile

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 EEA's *Asset Health Indicator Guide;2016*.

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. The aged based[31] asset health profile for our distribution cables are shown in Figure 6.17. All our subtransmission cables are less than 40 years old

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.

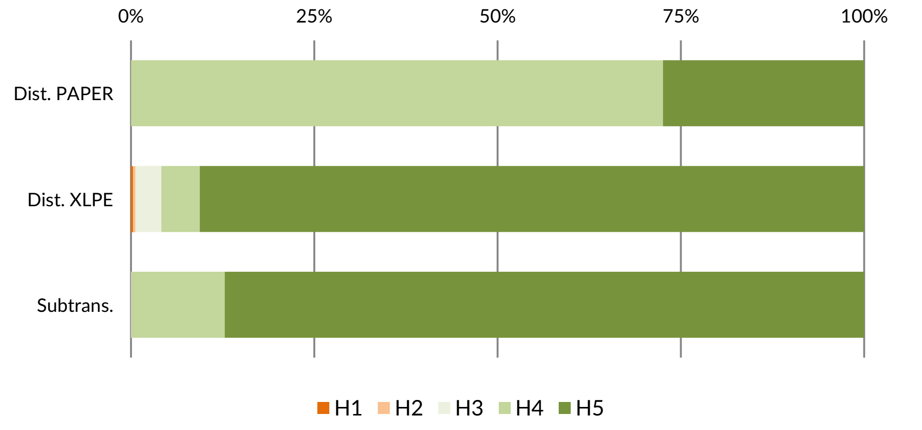


Figure 6.17 Underground cable asset health as at 2018

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 sub-transmission 11 kV cables were offline partial discharge tested every five years to monitor the condition. Recent joint failures to the sub-transmission cables have caused us to increase the 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.

6.4.5 DESIGN AND CONSTRUCT

Standardisation assists us in our ongoing management of this asset fleet. Using standard designs and equipment, we can 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 mm^2, 400 mm^2;630 mm^2, 33 kV 1C Al: 1000/1200 mm^2.
Distribution	11 kV, 1C and 3 C, Al: 35 mm^2, 95 mm^2, 185 mm^2, 300 mm^2, 400 mm^2
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

[31] In accordance with the EEA Asset Health Indicator Guide.

damaged by third parties) has been 2.5, with the greatest number in one year being 4 and the least being 0.

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[32] 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 a 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 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 subs for refurbishment, maintenance and operation. To date we have completed 16 replacements and have planned five 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 $ 14 M in zone substation renewals. This portfolio accounts for 16% 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.

[32] 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.

6.5.2 PORTFOLIO OBJECTIVES

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

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 SF_6 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 consumers 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 40 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, except one case, where three single phase units are installed. Figure 6.18 shows a typical zone substation power transformer.

6.5.3.2 POPULATION AND AGE STATISTICS

There are 28 zone substation transformers on our network, of which 23 are 33/11 kV units (with three connected as step-up 11/33 kV), two are 110/33/11 kV and two are 11/22 kV. The table below summarises our population of transformers by rating. Of the 28 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	5	17.8%
≥ 5 and < 9 MVA	5	17.8%
≥ 9 and < 20 MVA	8	28.6%
≥ 20 MVA	10	35.8%
Total	**28**	**100%**

Figure 6.18 Zone substation transformer – Cooneys Road substation

Our zone transformers age profile is shown in Figure 6.19. 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 more than 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 by a larger capacity, three phase unit in 2019 in response to load growth in the area.

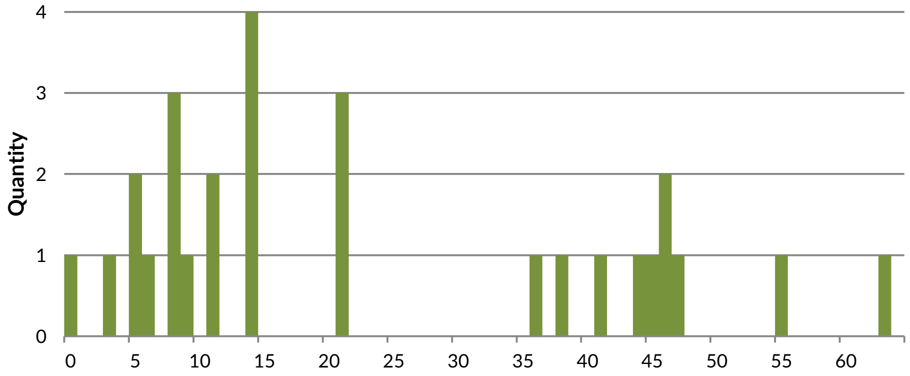


Figure 6.19 Zone substation transformer age profile in years.

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. The aged based[33] asset health profile for power transformers are shown in Figure 6.20.

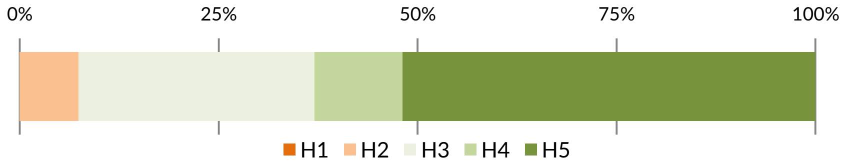


Figure 6.20 Power transformer asset health as at 2018

[33] In accordance with the EEA Asset Health Indicator Guide.

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. Our design specification is based on AS/NZS 60076 suite of standards which is based on the same IEC standard. We procure our transformers from a small group of transformer manufacturers.

To ensure good operational flexibility across the network we have recently started ordering 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 Table 6.14.

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.	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.	yearly
Routine planned maintenance: transformer, tap-changer, and	Four yearly and as required

Maintenance and inspection task	Frequency
mechanical/electrical auxiliaries. Insulation and winding resistance tests.	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 for 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 during AMP period 2014-2015.

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 their conditions reaching poor classification. The replaced transformers have usually been recycled around the network and used at other zone substations.

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

We do not plan to further modernise the fleet by elimination of remaining legacy power transformers before 2040 for the three oldest and by 2050 for the next four oldest. This strategy, will of course, be reviewed regularly over the intervening respective periods based on the annual analysis of peak MVA loadings, condition assessments, and performance history information.

Zone substation security requirements can be a reason for needing additional transformers. In this planning period, we, intend to add two power transformers in two zone substations to improve 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 BT 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 circuit breaker (CB) panels that are indoor type. These were installed in 2011 at the Pareora zone 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 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 CBs within 16 indoor 11 kV switchboards in our zone substations. The majority of our 11 kV zone substation indoor CBs are vacuum type (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.

6.5.4.2 POPULATION AND AGE STATISTICS

Table 6.16 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	143	12
Vacuum in SF_6	6*	1
Total	**166**	**16**

Figure 6.21 11 kV Indoor switchboard at North Street substation

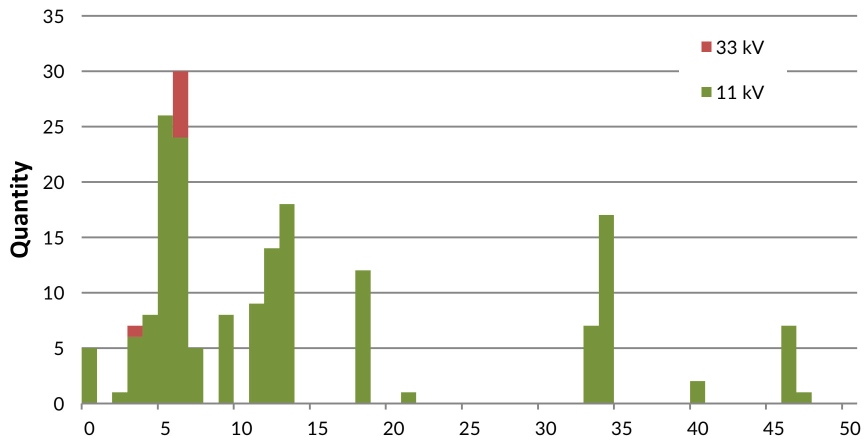


Figure 6.22 Indoor switchgear age profile in years.

Figure 6.22 show the age profiles for indoor type 33 kV and 11 kV circuit breakers. Our 33 kV CBs are six years or less old. The oldest CBs in our fleet are located in the Twizel township substation with ages of 46 and 47 years. The next oldest CBs are located at Unwin Hut zone substation and is 40 years old.

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 condition is primarily evaluated using asset age, typically expected lives and condition assessment.

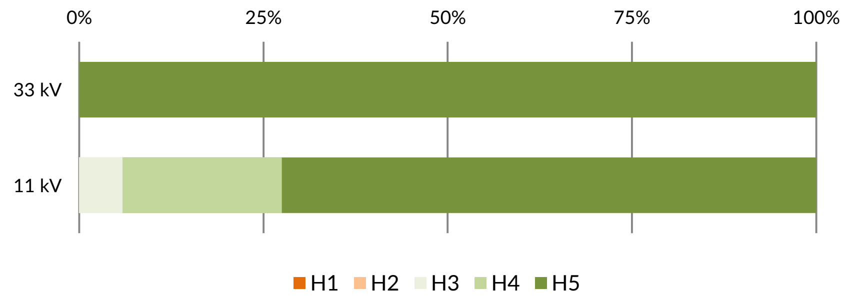


Figure 6.23 Indoor switchgear asset health as at 2018

The aged based[34] asset health profile for power transformers are shown in Figure 6.23.

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

Arc flash risk

Arc flash risk is a safety concern that is taken into account for our indoor switchgear fleet. Arc flash containment and detection is an integral part of our indoor switchgear specifications. Assessments are undertaken as part of our safety in design process to determine 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 6.17. The detailed regime for each asset is set out in our maintenance standard. Our various routine maintenance tasks are summarised in the table below.

Table 6.17 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.	Yearly
Insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. SF_6 gas pressure checks.	Four yearly
Vacuum circuit breaker diagnostic tests (e.g. HV withstand).	As required
Switchboard partial discharge test.	As required

[34] In accordance with the EEA Asset Health Indicator Guide.

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 6.18 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 ten year 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 and load break 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 our 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.

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 6.19 summarises our population of outdoor circuit breakers also broken down by interrupter type.

Table 6.19 Outdoor switchgear population by insulation media type and voltage rating.

Type	110 kV	33 kV	22 kV	11 kV
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

6.5.5.2 POPULATION AND AGE STATISTICS

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 is oil and vacuum in oil while recent 33 kV switchgear is SF_6 insulated. 33 kV CBs typically carry a function of protecting power 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

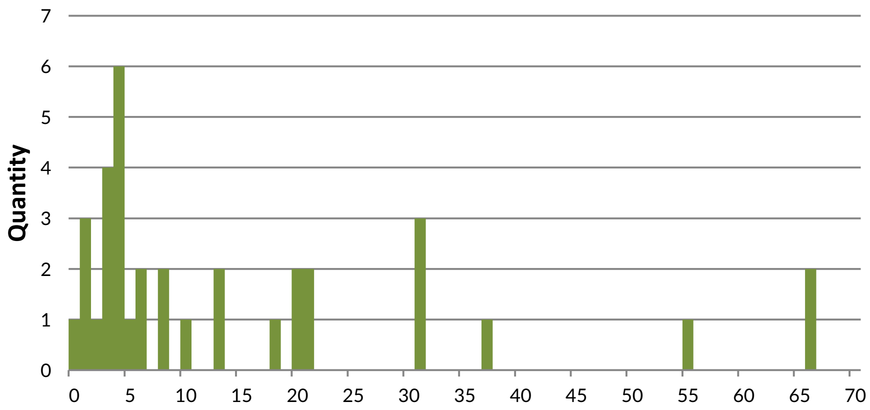


Figure 6.24 Zone Substation outdoor switchgear combined age profile in years.

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 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 based on the type of circuit breaker and the fault current breaking energy.

For outdoor switchgear, we define end-of-life as 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.

The aged based[35] asset health profile for power transformers are shown in Figure 6.25.

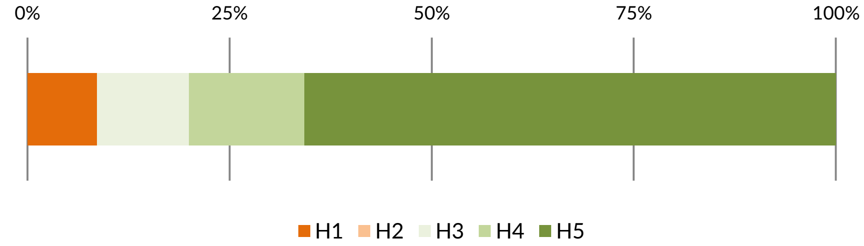


Figure 6.25 Outdoor switchgear asset health as at 2018

6.5.5.4 DESIGN AND CONSTRUCT

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 oil circuit breakers (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 6.21. The detailed regime for each asset is set out in our *Outdoor Switchgear Maintenance Standard*.

Table 6.21 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 the last 12 months. Condition-	Yearly

[35] In accordance with the EEA Asset Health Indicator Guide.

Maintenance and inspection task	Frequency
test circuit breakers including thermal, PD and acoustic emission scan.	
Circuit breaker insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. ABS thermal scan. Recloser thermal and oil insulation tests.	Four 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

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 based on condition. We aim to avoid outdoor switchgear failure. Network consequences can be high, and failure modes can be explosive, particularly with oil-filled switchgear.

Our in-service 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 6.22 Outdoor switchgear renewal approach.

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

Within the present ten year 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 the planning period.

Our longer term outdoor switchgear renewals quantity forecast useable 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 to detect and interrupt electrical faults while minimising the number of connections 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 can be connected to our SCADA network, thereby providing timely notice of system disturbances that are detected. 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.

Table 6.23 Zone substation protection relay population

Relay Type	Quantity	% of total
Electromechanical	49	11
Static	29	7
Numerical	364	82

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 device/s are replaced.

Our protection relay fleet is relatively modern with 93% 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 nuisance outages for consumers. Figure 6.26 shows a summary of our protection relay population based on age and quantity.

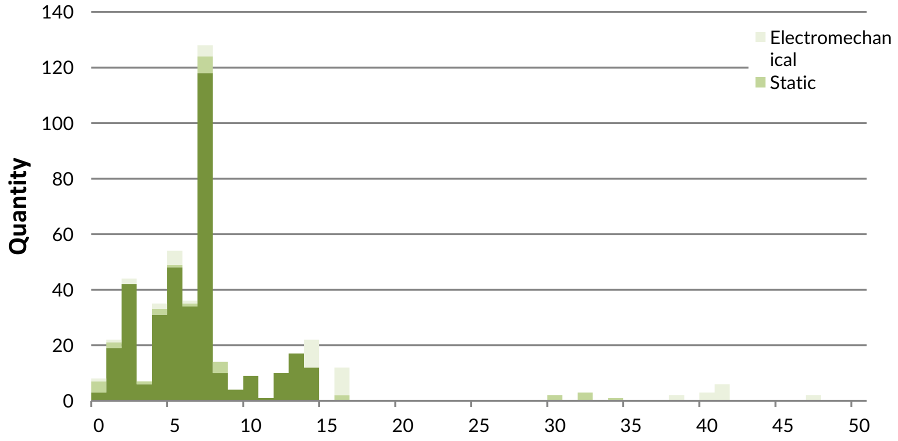


Figure 6.26 Zone Substation Protection Relays – Age profile

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 regarding protection system reliability. According to statistical information available in the industry, electromechanical relays' reliability reduces significantly after 30 years of service. To manage the risk to the network, some projects that is 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. The aged based asset health profile for our protection relays are shown in Figure 6.27

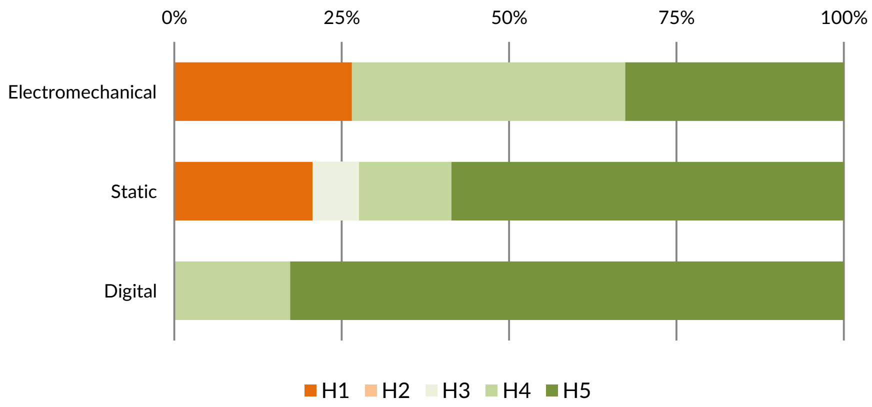


Figure 6.27 Protection relay asset health as at 2018

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.

We have replaced replaced nine static protection relays at our Tekapo substation that were over 30 years old with modern numeric devices. This project was completed in 2018. In 2019, 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 being 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 beyond their structural design.

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 6.24 summarises our population of zone substation buildings by age groups.

Table 6.24 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**	**100**

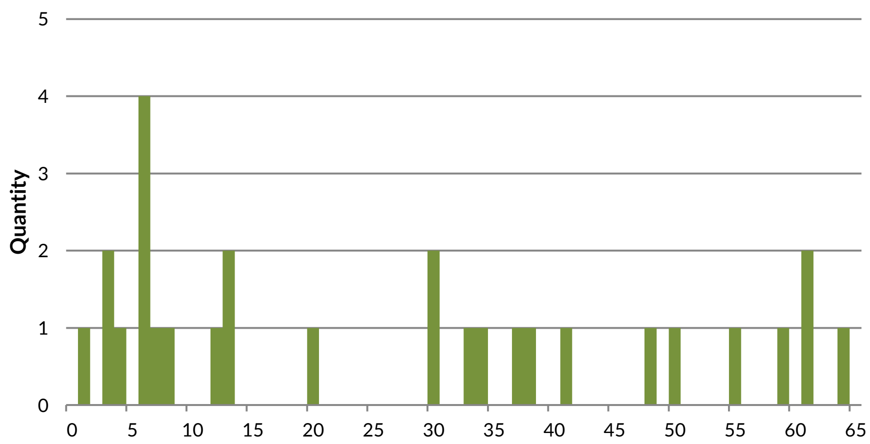


Figure 6.28 outlines the age profile of the zone substation building fleet.

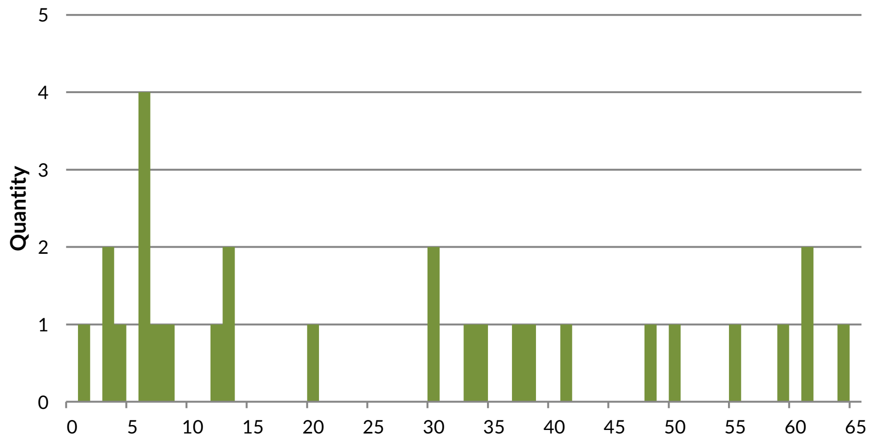


Figure 6.28 Zone substation buildings age profile in years

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 hasn't housed a ripple plant for many years and is surplus to requirements. One 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 has been standardised in terms of functionality. The size varies to suit the various substations. We also consider the 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 6.25 Load control injection plant maintenance and inspection tasks

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

Two of our smaller legacy switch room buildings at Twizel and Unwin Hut will be replaced with new buildings or alternative 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 consumers with controllable loads (e.g. hot water or space heating) and also to shed load such as irrigation when required.

If configured well, 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 transmission deferral.

Figure 6.29 Load control injection plant – Bells Pond zone 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 6.26 summarises our load control injection plant population by type.

Table 6.26 Zone substation load control injection plant population

Type	Plant	% of Total
Modern electronic plant	5	83%
Legacy rotary plant	1	17%
Total	**6**	**100%**

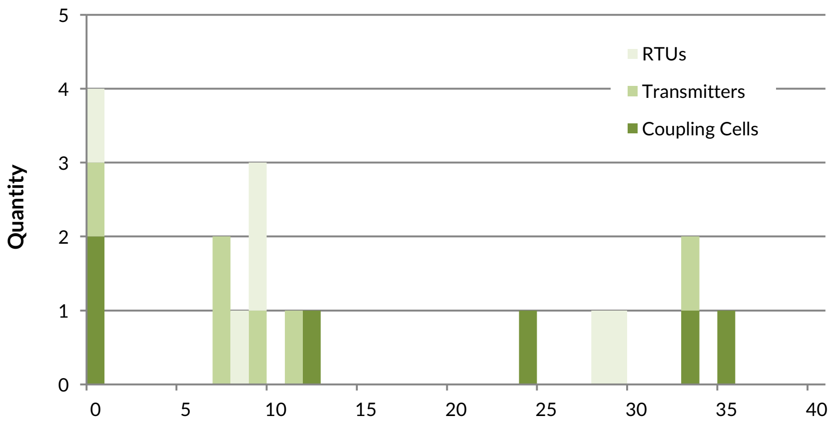


Figure 6.30 Zone substation load control injection plants age profile in years.

6.5.8.3 CONDITION, PERFORMANCE AND RISKS

A new ripple 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 Smart Meters and associated programmable ripple relays.

The aged based asset health profile for our ripple plants are shown in Figure 6.31.

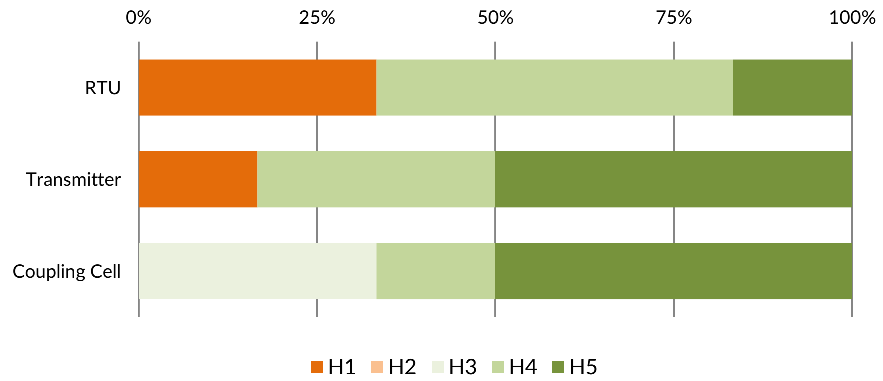


Figure 6.31 Load control plant asset health as at 2018

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 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 will 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 6.27 Load control injection plant maintenance and inspection tasks

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

The ripple plant at our Bells Pond zone substation had the coupling cell upgraded in 2017 to accommodate the second transformer that has been installed in 2018. The transmitter is adequately rated and will not be upgraded.

Our ripple plant at Timaru substation will be replaced in 2019. 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 ASSET FLEET MANAGEMENT

6.5.9.1 FLEET OVERVIEW

The other zone substation asset 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[36]. 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 is being rebuilt because of load growth and due to the age of the equipment. 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 6.28. The detailed regime is set out in our maintenance standards.

Table 6.28 Other assets maintenance and inspection tasks

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

[36] See lightning density map for South Canterbury here:

6.5.9.5 RFENEW 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 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 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.

Portfolio summary

Investment in distribution transformers is forecast at $ 15.8 M over the planning period. This portfolio accounts for 18% 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 6.29 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 substations and transformers step down voltage for local distribution. Pole mounted transformers are generally smaller and supply fewer consumers 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 6.32.

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 6.33.

Voltage regulators 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 6.33.

Figure 6.32 Pole mounted distribution transformers

Figure 6.33 Ground mounted transformer (left) and voltage regulator (right)

6.6.4 POPULATION AND AGE STATISTICS

Distribution substations and transformers step down voltage for local distribution. 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 1950s, early 1970s, 2000s, and 2010s.

Table 6.30 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 in-service age and quantities of distribution transformers by kVA rating and distribution substation type are given in Table 6.30, Figure 6.34, and Figure 6.35 respectively.

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.

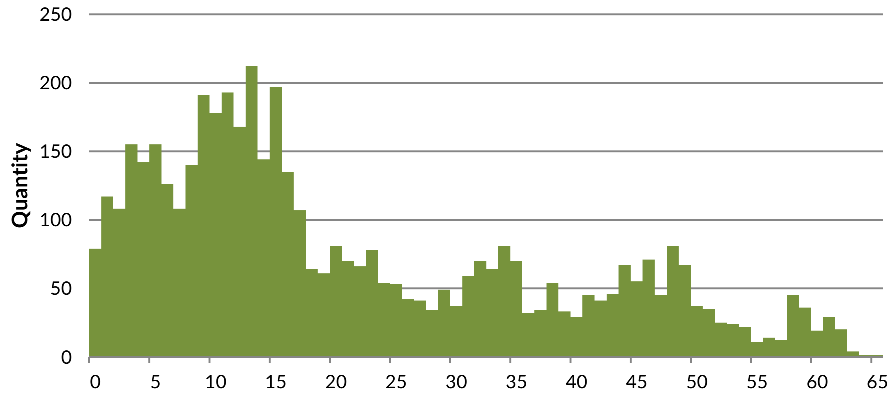


Figure 6.34 Pole mounted distribution transformer age profile in years.

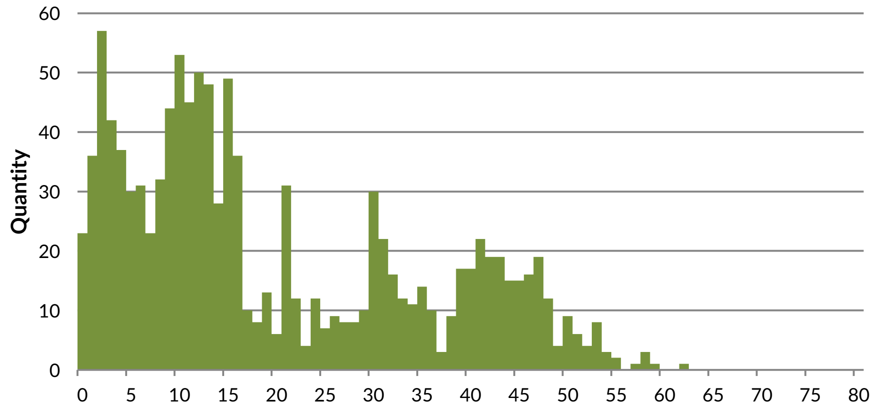


Figure 6.35 Ground mounted distribution transformer age profile in years.

We have some 33 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 2000s.

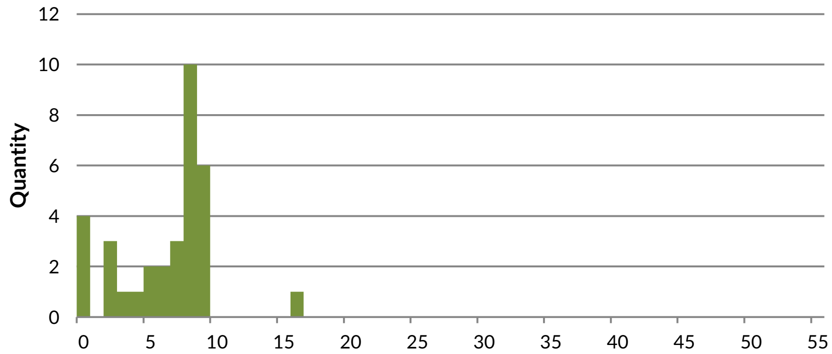


Figure 6.36 Voltage regulator age profile in yeas.

6.6.5 CONDITION, PERFORMANCE AND RISKS

Overall our distribution transformer fleet is in a good condition. Because of the standards to which they are designed and manufactured, they are capable of operating beyond their nameplate ratings. The aged based[37] asset health profile for our distribution transformers are shown in Figure 6.37.

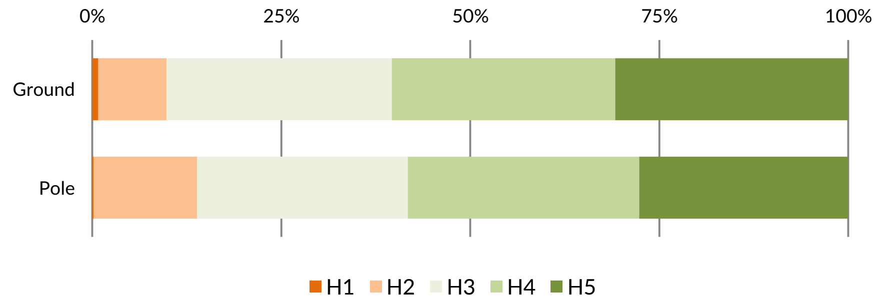


Figure 6.37 Distribution transformer asset health as at 2018

The biggest risk to our fleet is lightning and vehicles coming into contact with our poles.

[37] In accordance with the EEA Asset Health Indicator Guide.

The aged based[38] asset health profile for voltage regulators are shown in Figure 6.38. From the graph it is clear that our regulator fleet is young in comparison to the ODV expected end of life of 55 years.

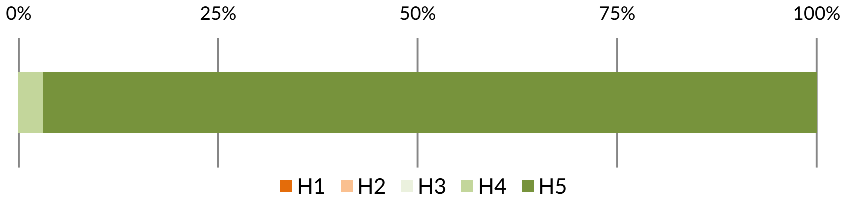


Figure 6.38 Voltage regulator asset health as at 2018

6.6.6 DESIGN AND CONSTRUCT

Distribution transformers are designed and constructed to international standards. Our distribution transformer suppliers design and tested to AS/NZS 60076 and AS 2374 respectively. They are robust pieces of equipment that seldom fail. When sizing transformers for a specific application, we do allow for some measure of future growth. This eliminates the need to upgrade transformers regularly as a result of generic load growth. The incremental premium payable for the increased capacity is well below any upgrade or replacement costs.

We have standard construction design standards for both pole mounted- and ground mounted transformer installations. This allows us to efficiently construct and maintain installations. For pad mount transformers we utilise a design standard as prepared by registered chartered engineers to ensure withstanding of earthquakes.

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 programs.

Distribution transformers do not require intrusive maintenance. Pole mounted transformers are often run to failure as these are easily replaced at a much lower cost than to implement a maintenance regime. Large ground mounted transformers 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 because 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 transformers are proactively replaced based on age and condition. All scrapped transformers' oil is drained and recycled through certified processors.

6.7 DISTRIBUTION SWITCHGEAR

6.7.1 OVERVIEW

This section describes our distribution switchgear portfolio and summarises our associated fleet management plan. An overview of these assets including their population, age and condition are also given. The portfolio includes the following fleets:

- **Ground mounted switchgear** which consists 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 are 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 6.39 with the red arrows pointing to a fuse link on the left and an ABS on the right.

[38] In accordance with the EEA Asset Health Indicator Guide.

Figure 6.39 Fuse link left and an ABS right

6.7.2 PORTFOLIO OBJECTIVES

The portfolio objectives for our distribution switchgear fleet is summarised in Table 6.31.

Table 6.31 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 promptly.
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 6.40 shows our population and age profile for our RMU types on our network. Around twenty-three percent (all oil) are at or just beyond the ODV life of 40 years.

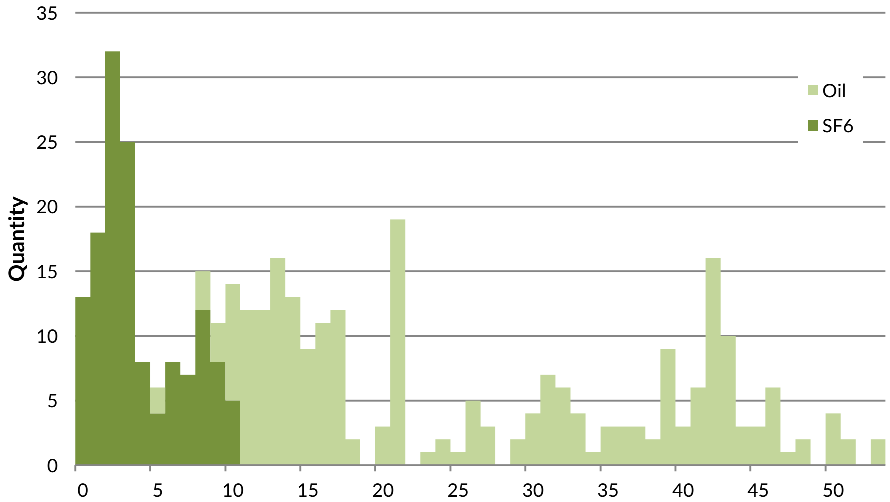


Figure 6.40 RMU age profile in years.

As shown in our SF_6 insulated RMUs are relatively new with the oldest just on eleven years of age. We have standardised on three types of RMUs

6.7.3.2 POLE MOUNTED FUSES AND SWITCHES

We have approximately 7565 pole mounted fuses and switches on our network with ages as shown in Figure 6.41 and Figure 6.42.

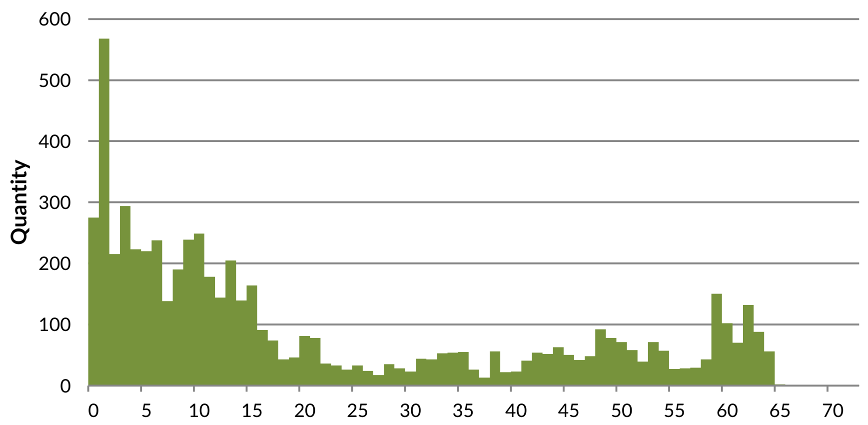


Figure 6.41 Pole fuse age profile in years.

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.

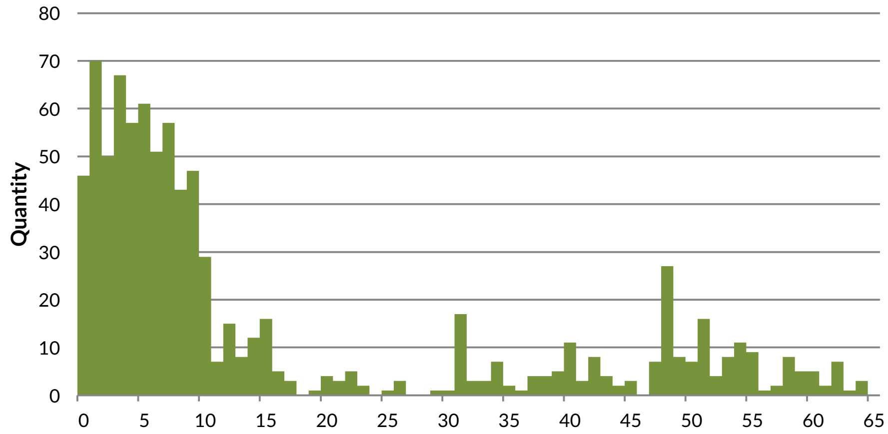


Figure 6.42 Pole switch age profile in years.

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 6.32. 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 6.32 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

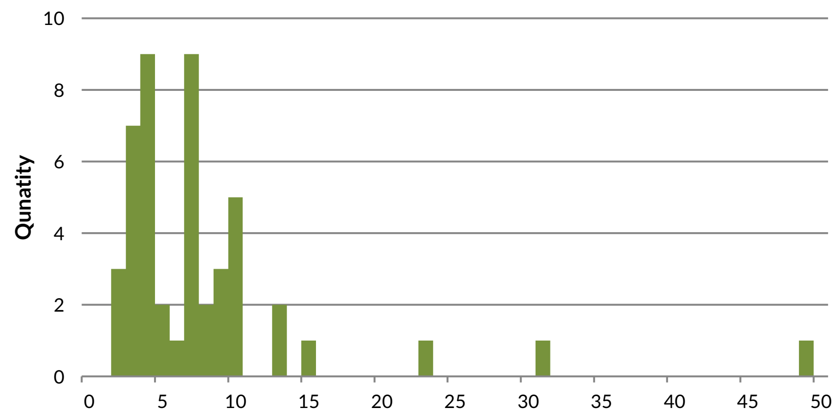


Figure 6.43 Recloser age profile in years.

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 are close to their ODV end of 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 is 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 remote control functionality and will continue this practice as part of our renewal and replacement programs. The aged based[39] asset health profile for our RMUs are shown in Figure 6.44.

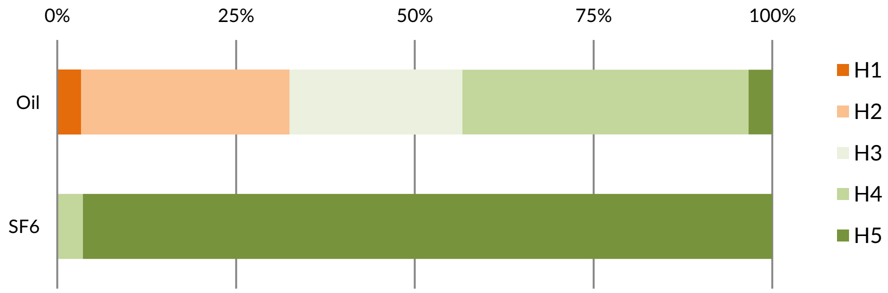


Figure 6.44 RMU asset health as at 2018

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 our SF_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 and the asset health profile is shown in Figure 6.45. 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.

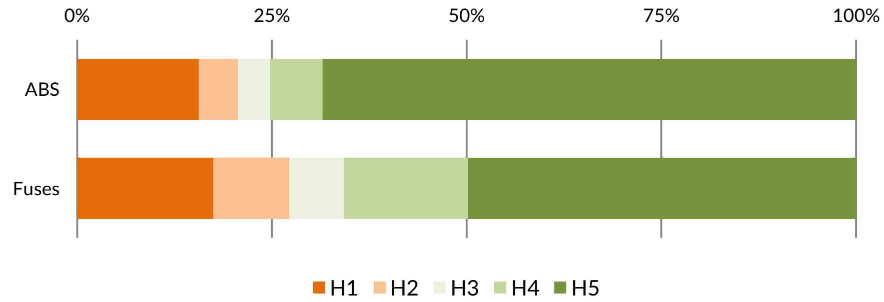


Figure 6.45 Pole mounted fuse and switch asset health as at 2018

6.7.4.3 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS

The aged based[40] asset health profile for reclosers are shown in Figure 6.46. 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 five 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.

[39] In accordance with the EEA Asset Health Indicator Guide.

[40] In accordance with the EEA Asset Health Indicator Guide.

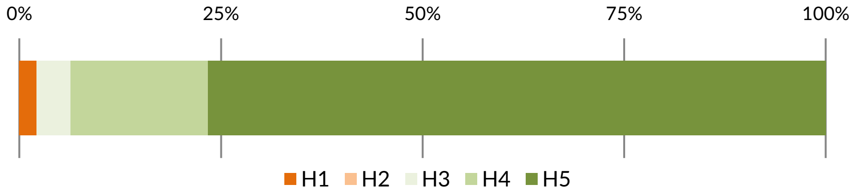


Figure 6.46 Recloser asset health as at 2018

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 CBs 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 CBs 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 fibreglass 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 by passed by an air break switch (ABS) or disconnector to allow supply to be maintained during maintenance of the reclosers and in the event of a failure of a recloser 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 prolonged consumer outages and SAIDI penalties.

We have also embarked on a programme of remote control and indication 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 remotely controlled. All 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 install remote control and indication functionality. This allows us to operate them from our control room which reduces outage times and improves reliability. To date we have upgraded 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. We also budget to replace units that fail during operation in addition to replacements under the overhead line replacement and renewal program.

The 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 five 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, remote terminals units (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 STATIONS

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 zone 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)

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 toward 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 a vital infrastructure ensuring that network controllers can communicate 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 are listed in the Table 6.33.

Table 6.33 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 a digital platform.

6.8.3 POPULATION AND AGE STATISTICS

In the previous years we have undertaken a number of projects to modernise our RTUs to provide acceptable levels of service. In this planning period, we intend to focus on replacing the three remaining legacy RTUs.

Table 6.34 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 6.34 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 the requirement of an intermediary RTU.

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

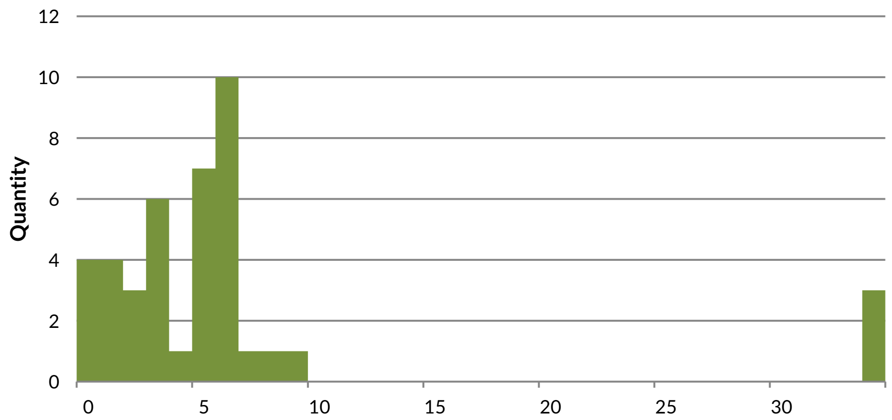


Figure 6.47 Zone substation SCADA and communications age profile

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. The aged based asset health of our RTUs are shown in Figure 6.48.

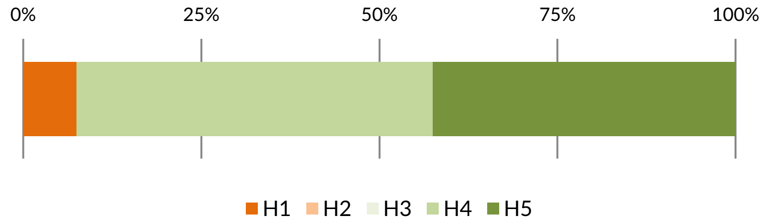


Figure 6.48 RTU asset health as at 2018

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 the 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 consumers.

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 6.35 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.	Six monthly
RTU operational checks.	Visual inspection of communication cables/lines, checking for condition degradation. Attenuation checks. Antennae visual inspections, with bearing and polarity verified.	Yearly
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 three 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 can 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.

6.9 MATERIAL REPLACEMENT AND RENEWAL PROJECTS

This section details the material projects that are primarily driven by a need for renewal or replacement. These projects are either already underway or are to be started in the next financial year. We have defined material projects as those projects where:

- The expenditure is in excess of $250 k
- The project will be replacing critical assets
- Where a lack of this expenditure could have a high consequence on our ability to supply electricity to consumers

Timaru substation ripple plant replacement

Estimated cost	$700 k
Project timing	2019

The TIM ripple plant was originally commissioned in 1982 and is now at the end of its life. It is our largest ripple plant and is vital to our load control strategy for the Timaru and surrounding area.

Consideration was and still is given to effect load control through advanced meters but this functionality has not yet been proven to the extent that it could replace ripple control plants.

Overhead conductor replacement – Albury area

Estimated cost	$525 k
Project timing	2019/20

This project will replace seven kilometres of overhead copper conductor. Drivers for this replacement are the age and condition of the copper conductor as well as the increased fault levels due to the upgrade of the transformer at the Albury GXP by Transpower.

Overhead conductor replacement – Fairlie area

Estimated cost	$400 k
Project timing	2019/20

This project will replace seven kilometres of overhead herring conductor along School Road in the Fairlie district. The main drivers for this replacement are the age and condition.

Overhead line renewal – Studholme area

Estimated cost	$492 k
Project timing	2019/20

This project will replace and renew 33 kilometres of overhead line in the Tara Hill area. The main drivers for this replacement are the age and condition.

Overhead line renewal – Studholme area

Estimated cost	$342 k
Project timing	2019/20

This project will replace and renew 23 kilometres of overhead line along Hook School Road. The main drivers for this replacement are the age and condition.

Underground substation replacement – Timaru CBD

Estimated cost	$500 k
Project timing	2019/20

We have 31 underground distribution substations in the broader Timaru CBD area. They were mainly installed in the 1960s and 1970s. These substations consist of a ring main unit (RMU), distribution transformer and a low voltage switching panel. Most of the RMUs are of the oil type and as such would present a fire hazard in case of a catastrophic failure.

With the changes in the health and safety practice area, these substations are also classified as a confined space and as a result the associated operating and maintenance costs are high. We plan to replace one to two of these substations per annum. The main challenge with this replacement program is real estate to locate the replacement substation as well as maintaining the supply of electricity while transferring load from the old to the new substation.

6.10 NON MATERIAL PROJECTS

This section summarised the non-material projects that does not meet the criteria for material projects but are never the less still important to ensure and maintain a safe and reliable supply of electricity to our consumers. The projects are listed in the table below.

Two pole substation replacement & renewal

Estimated cost	$490 k
Project timing	2019/20

We have approximately 130 two pole substations across our network. This budget represents several projects with a range of different scopes. Some substations are replaced with equivalents on the ground while others are rebuilt with new poles while some will only have the platforms reinforced or replaced.

Lucy Box replacement program

Estimated cost	$250 k
Project timing	2019/20

In the Timaru CBD area many low voltage supply cables are in the footpaths with distribution and link boxes underground. This older type link box (Lucy box) was designed to be filled with pitch. Over the years the pitch has melted and expanded to the extent that operating the links within the box is no longer possible. This presents us with challenges to operate and maintain connected equipment. It also restricts us in configuring the network for planned and unplanned outages.

We have approximately 48 of these link boxes left and this is an ongoing program to replace at least five of these link boxes per annum given the constraints in the CBD area and the challenges to maintain supply while we construct the replacements..

Overhead line renewals

Estimated cost	$1.05 M
Project timing	2019/20

Over and above the material overhead line projects listed in the previous section we are also planning an additional seven smaller overhead line replacement and renewal projects across our network. These range in size with budgets from $88 k to $296 k and they are:

- Pentland Hills / Kaiwarua Road – 19.7 km
- Geraldine township feeder – 1.25 km
- SH 8 Kimbell, Three Springs Rd to Kimbell T/S – 2 km
- Sutherlands - L240 to L205 & L241 – 10.6 km
- Opihi Terrace Rd – 6.7 km
- Birch Hill to Unwin Hut 33kV line – 5.48 km
- Timaru Sub to PLP 33 & 11 kV lines – 15.5 km
- Tengawai River - from L205 – 5.9 km
- Limestone Valley & Davison Road – 8.88 km

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 internationally 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.

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

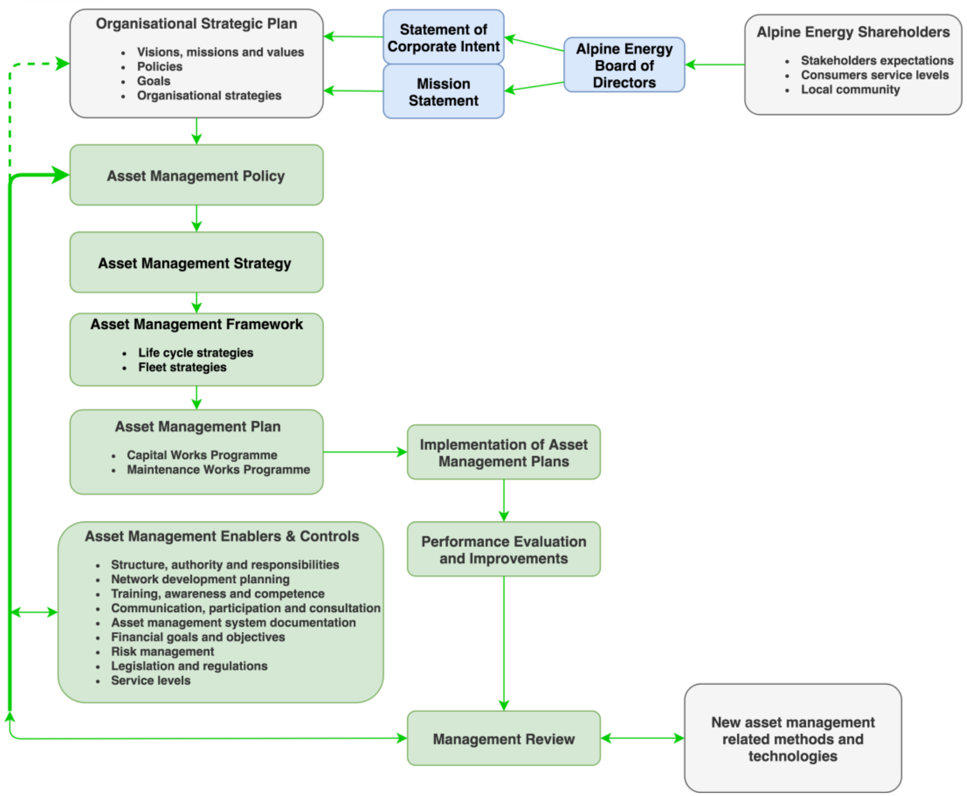


Figure 7.1 Asset management system

7.2 PEOPLE

Our people are our most important asset and we recognise that the right and sufficient competencies are essential to achieving our asset management objectives. We have grown from a staff complement from thirty-five in 2010 to just on eighty in 2018. This reflects not only the level of work around dairy conversions and processing on our network but also our commitment to developing 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 2014/15 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 still is 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.

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 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 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 and several bespoke systems that were managing asset data. Due to the complexity of the task to replace our financial system and implement a linked asset management system at the same time, we reduced the associated risks by keeping the asset management functionality to a minimum and by using 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 a number of additional asset management functionalities that we want to implement as subsequent stages in the coming years.

OneEnergy contains the bulk of our asset data with respect to type, age, model, number and various other generic and asset-specific attributes. OneEnergy is also linked to our GIS. All condition data as well as maintenance schedules for various asset types are contained within OneEnergy. Our service providers have access to OneEnergy for the loading and updating of asset condition information flowing from the maintenance activities.

Since the implementation of OneEnergy we have been reviewing and improving asset data continuously. Due to the many bespoke asset information systems used before OneEnergy, asset data, though available, is not always in the most appropriate format or location that allows for easy or automatic extraction to populate our new system. In many instances, this process of data extraction and transferring to OneEnergy is a manual process.

We have approved and budgeted for an asset audit/walkdown project to verify and gather asset data required in OneEnergy to allow more accurate reporting, data manipulation, condition monitoring and more focussed asset expenditure. The budget estimate for this project is $1.4 M over two years. In our opinion, our asset data is approximately 90% or just above with respect to completeness and similar for accuracy specifically with respect to high value and critical assets.. The purpose of the asset audit/walkdown project is to improve on this number as much as practically possible. The project is planned for the 2019/20 and 2020/21 financial years.

7.3.2 BUSINESS PROCESS MAPPING

Our existing business process maps are being revised as we mature in our use of the OneEnergy EAM solution. As noted above we initially only utilised the 'out of the box' functionality and processes that OneEnergy offers but as we increase our use of the functionality available processes are reviewed and refined accordingly. 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 completed a basic integration between our GIS system and our EAM system. We are in the process of integrating our GIS and SCADA system, specifically with the OMS module to improve our outage reporting and communications.

The availability of the GIS system to provide mobile solutions has also been utilised and combined with an interface to our EAM to leverage the best capabilities of both systems from a single interface.

7.3.4 SUPERVISORY CONTROL AND DATA ACQUISITION SYSTEM

Our recently upgraded supervisory control and data acquisition (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 prioritising
- Improved consumer relations by providing accurate outage and restoration information
- Ability to prioritise 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.

Through a combination of our OneEnergy solution and the GIS mobility platform we can perform automated validation checks at the point of data entry for those fields which lend themselves to this form of quality check. At the next level of oversight, we are developing a series of views within our Tableau reporting platform to enable engineers to check the data coming back from the field for validity and follow-up action if required.

We have now embarked on a multi-year 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 are being moved into this electronic format and are expected to be complete by the end of 2019. All staff within Alpine and NETcon have controlled access to drawings which are always the latest copy.

Our standards database has now been moved into ADEPT to improve the management of standards and remove another bespoke system. We continue to look at other process improvements where ADEPTs functionality and workflow can be utilised and these will be integrated as they are identified. In this regard, we have budgeted for the integration of ADEPT with our GIS system and specific with respect to asset attachments.[41]

7.3.7 INTEGRATION ACTIVITIES

The recent Implementation of four major and modern asset related systems (OneEnergy EAM, ESRI GIS, Survalent SCADA and ADEPT Drawing Management) has raised the opportunity to integrate our asset related systems in a way that was not previously possible. Our concept behind integration is to reduce the effort required from a user to find all information on an asset, to store the data in one place only without replication and to provide improved data control and therefore, confidence that the data is correct. Steps have already been taken along this line in the following areas.

- Asset attributes from OneEnergy are available to view within GIS
- Drawings managed and stored within ADEPT are available within GIS
- Work Order visual representations are available within GIS
- Bi-directional automated links are in place between GIS and OneEnergy to facilitate a user moving between related records in either system
- The use of GIS mobility products to collect field data that is processed directly into One Energy
- The linking of features in GIS to assets in SCADA

We will be continuing to explore new areas of integration and additional ways of leveraging our existing integration.

7.4 NON-NETWORK ASSETS

7.4.1 DRONE TECHNOLOGY

We continue to collaborate with like-minded energy companies to progress Beyond Visual Line of Sight (BVLOS) development using drone technology.

[41] The attachments that are in view here are photographs, drawings, easements to name a few.

Our challenges over the years have been to reduce outages and speed up outage response times, increase public and staff safety, identify levels of storm / other damage quickly and efficiently, and improve vegetation management strategies.

Drone technology is seen as evolving technology/solution to assist with us these challenges as well as complement our approach to asset condition management.

7.4.2 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 can view power quality characteristics of our low voltage network. Before 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 also to utilise this for network benefits.

7.4.3 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 the financial year 2019/20 is the redevelopment of the Washdyke yard. This will include appropriate storage and management of network equipment spares, vehicle storage and traffic management.

Figure 7.2 Our new office building

7.4.4 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.

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 7.3 gives a summary of our current asset management maturity assessment tool (AMMAT) scores.

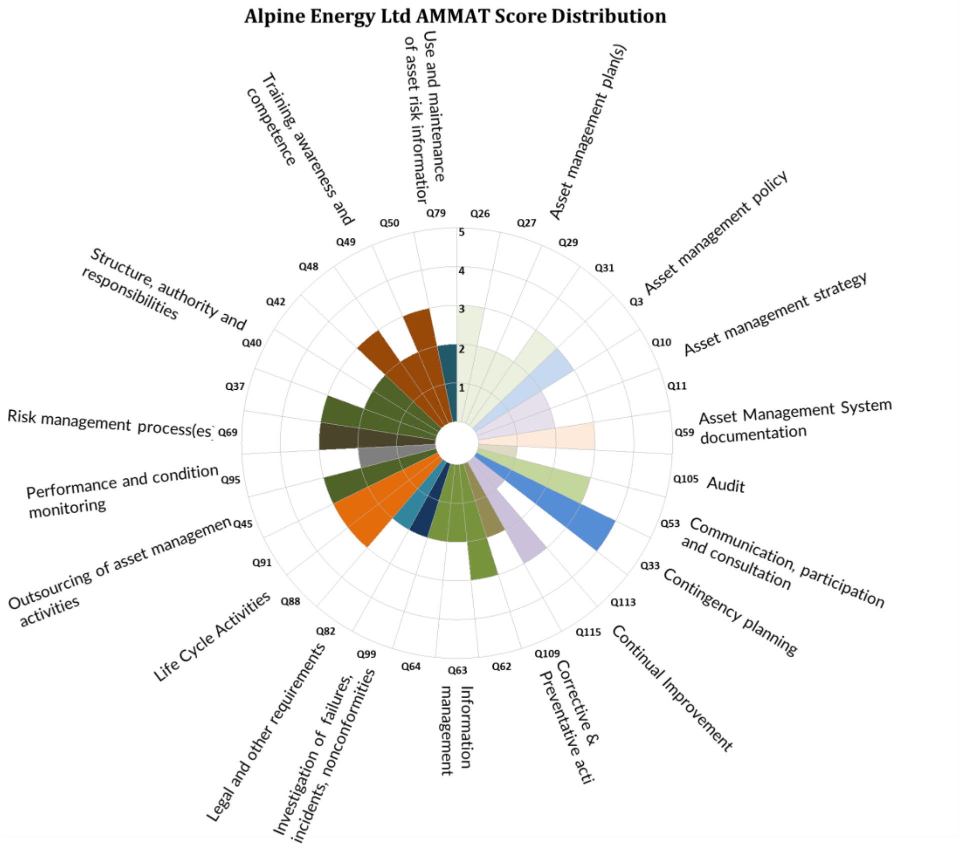


Figure 7.3 Our AMMAT scores

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 plans	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. Our communications plan has been developed and is being reviewed. All projects and jobs are captured against relevant assets within our EAM system. Business Process Maps have been developed for our new EAM system.
Communication, participation and consultation	We have developed a draft communications plan. The plan is being reviewed and will be socialised throughout the organisation within the first three months of the new financial year.
Life cycle activities	As part of implementing our 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 new EAM system, KPIs will be defined and measured.
Continual improvement	We support and encourage all technical staff, especially engineers to attend the annual EEA conference where new technologies and systems are marketed and displayed. Most staff involved in asset management are affiliated to industry and international bodies such as Engineers NZ, Cigre, IEC, IEEE etc.

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 the table below.

Table 7.2 AMMAT scores improvement initiatives

Asset Management Function	Improvement Identified	Timeframe
Asset management policy	Target audience informed and policy reviewed.	Three yearly review.
Asset management strategy	Develop performance targets and review processes.	12 months

Asset Management Function	Improvement Identified	Timeframe
Asset management plan(s)	Complete fleet strategies for all asset types	12 months
	Review draft communications plan and formalise throughout the organisation.	3 Months
	Measure effectiveness of the communications plan	Continuous
Contingency planning	Establish regular testing and exercising programme.	Yearly
Structure, authority and responsibilities	Align job descriptions with AM and Portfolio objectives and strategies in this Plan.	Yearly
	Develop a resource strategy	12 months
	Review draft communications plan and formalise throughout the organisation.	3 months
Structure, authority and responsibilities	Develop a resource strategy	12 months
Communication, participation and consultation	Review draft communications plan and formalise throughout the organisation.	3 months
Risk management process(es)	Complete all major project risk assessments in Delphi	18 months
Audit	Develop an audit plan for our AMS	Two years


Veefil
ELECTRIC VEHICLE FAST CHARGER
Alpine
ENERGY
ChargeNet.nz
Electric Vehicle Rapid Charger

8. FINANCIAL SUMMARY

This chapter summarises our financial performance against previous budget forecasts and our expenditure forecasts for the planning period. All data and graphs are given in constant dollar values as at September 2018. We have assumed a price inflator of 2% to calculate the nominal dollar values for the numbers in information disclosure schedules 11a) and b).

8.1 PERFORMANCE AGAINST PREVIOUS PLAN

Table 8.1 below shows the variance between the forecast and actual expenditure for the 2017/18 financial year.

Table 8.1 Variance between actual and forecast expenditure in 2017/18

Variance between actual and forecast	Forecast ($'000)	Actual ($'000)	Variance %
Capital expenditure			
Consumer connections	2,200	3,798	+73%
System growth	6,571	6,859	+4%
Asset replacement & renewal	5,857	5,811	-1%
Reliability, safety & environment	1,578	798	-49%
Subtotal – Capital expenditure on network assets	18,206	19,293	+6%
Operating expenditure			
Service interruptions & emergencies	1,344	1,748	+30%
Vegetation management	611	431	-29%
Routine & corrective maintenance & inspections	3,000	2,520	-16%
Asset replacement & renewal	289	701	+143%
Subtotal – Operating expenditure on network assets	5,244	5,400	+3%
Total expenditure on network assets	23,450	24,693	+5.3%

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.

Our overall capex on the network was slightly over budget mainly due to consumer connections expenditure. This expenditure also realises a capital contribution in most instances. Expenditure in consumer connections has exceeded our planned budget by 73%. This was mainly attributable to strong performance in subdivisions, commercial development (including Fonterra), and residential projects. The budget for reliability, safety & environment was underspent by 49% which was due to an under-expenditure against the budget to replace old locks with new Abloy type locks. The budget for these lock replacements have been reduced for the 2019 budget year.

Our overall opex on the network was slightly over budget by 3%. The over-expenditure on service interruptions and emergencies is mainly due to increased costs associated with staff on call. While vegetation management expenditure was down, it can be attributed to increased second and subsequent trimming of vegetation which is for the consumers' account. Asset replacement and renewal expenditure was substantially above budget due to

8.2 EXPENDITURE FORECASTS

8.2.1 CAPEX

Our current forecast for total network capex for the planning period is given in Figure 8.1and Table 8.2.

Both Capex and Opex values are expressed in constant dollar amounts unless otherwise specified. The values have been adjusted using an inflator of 2%[42] which approximates annual inflation for the next ten years to calculate nominal dollar values.

All expenditure values shown in tables in this section is in $-millions unless stated otherwise.

[42] From most recent Treasury forecasts.

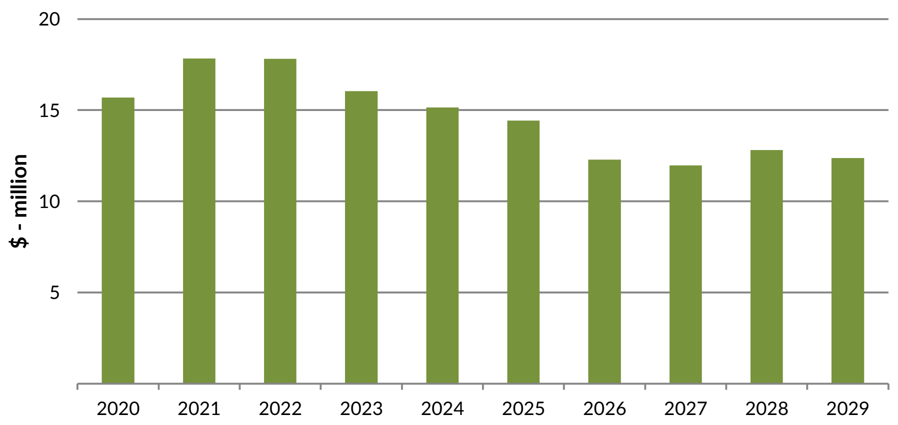


Figure 8.1 Total CAPEX for the planning period

Table 8.2 Total CAPEX for the planning period

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
15.70	17.84	17.81	16.04	15.14	14.42	12.28	11.96	12.80	12.37

Our total capex includes the following expenditure categories:

- **Network development Capex** which includes growth, consumer 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 ICT infrastructure and systems, property, equipment, and vehicles.

Totals for the above capex categories' budgets for the planning period is shown in the graphs and tables below.

8.2.1.1 NETWORK DEVELOPMENT CAPEX

Investment on consumer connections is the main contributor to network development capex. Growth projections are moderate mainly due to the shelving of the Hunter Downs Irrigation scheme and the fact that dairy conversions have slowed. Most of the arable farmland in South Canterbury that can be irrigated is now under irrigation. Conversions from border dyke irrigation to pivot irrigation could see an increase in growth expenditure in future.

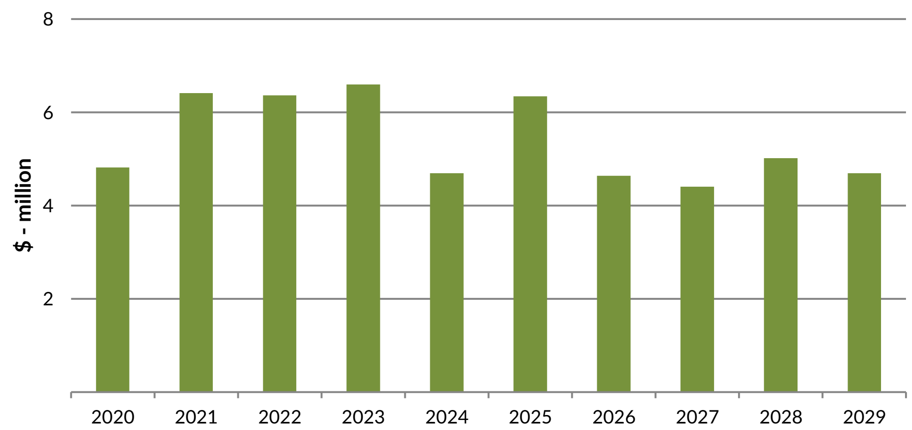


Figure 8.2 Network development capex for the planning period

Table 8.3 Network development capex for the planning period

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
4.83	6.40	6.36	6.60	4.69	6.34	4.64	4.40	5.01	4.69

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. 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 below.

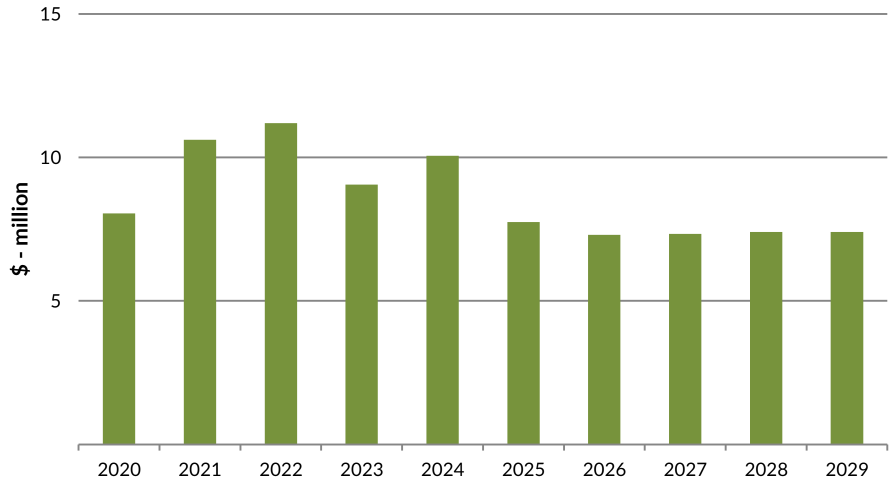


Figure 8.3 Fleet management capex for the planning period

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 relocation of our Twizel zone substation in 2019-2020, and the replacement of our Tekapo zone substation switchboard in 2024.

Table 8.4 Fleet management capex for the planning period

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
8.05	10.61	11.19	9.05	10.05	7.75	7.30	7.34	7.40	7.40

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 below.

Table 8.5 Non-network capex projects for 2018/19

Project / Initiative	Budget ($)
IT	957 k
Washdyke yard development	1.1 M
Asset management system	700 k

Non-network capex for the planning period is given in the figure and Table 8.6 below.

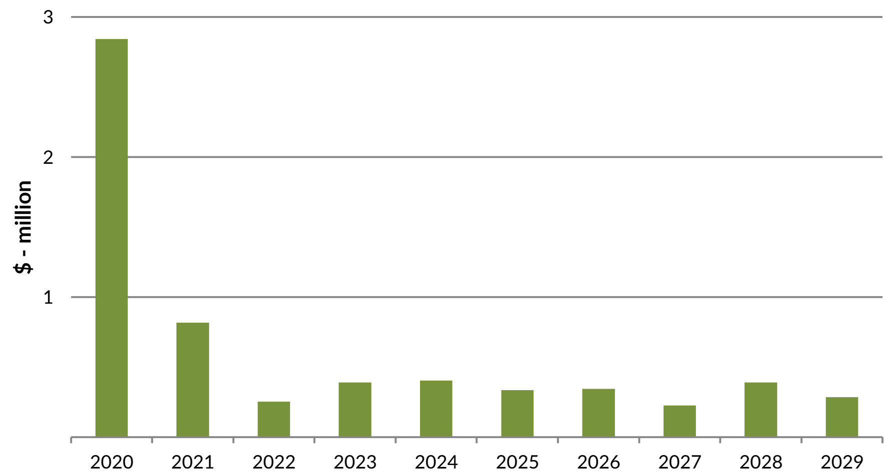


Figure 8.4 Non-network capex for the planning period

Table 8.6 Non-network capex for the planning period

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2.84	0.82	0.25	0.39	0.40	0.33	0.34	0.22	0.39	0.28

The IT infrastructure budget consist of:

- integration of Adept to GIS for attachment management
- asset walkdown/audit project to verify and improve the quality of our asset data as migrated from our legacy systems into OneEnergy
- business development using drone technology

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.

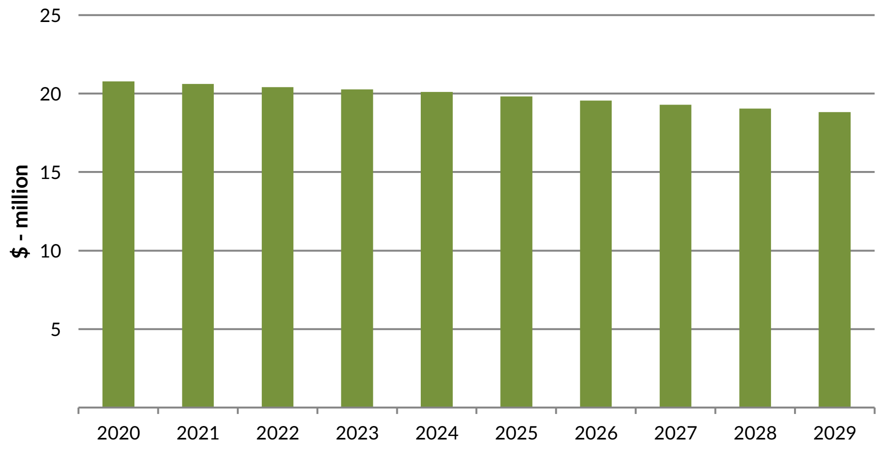


Figure 8.5 Total opex for the planning period

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 five years (in nominal terms). Thereafter for the remaining five years of the planning period, we forecast a slight opex reduction in constant dollar terms.

Table 8.7 Total opex for the planning period

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
20.78	20.61	20.41	20.27	20.10	19.82	19.56	19.28	19.04	18.81

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 below gives our direct network opex for the planning period.

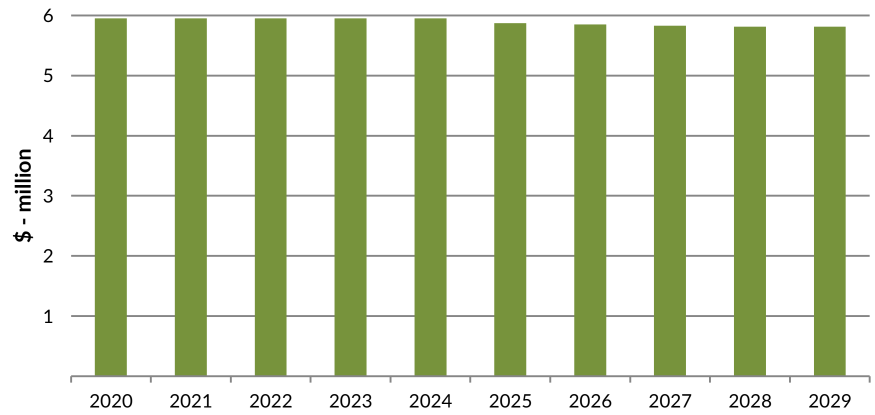


Figure 8.6 Direct network opex for the planning period.

Table 8.8 Direct network opex for the planning period

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
5.95	5.95	5.95	5.95	5.95	5.87	5.85	5.83	5.81	5.81

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.

Our forecast opex per asset categories is detailed in Table 8.9.

Table 8.9 Opex per asset category

Asset Category	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
LVLines & cable	0.37	0.36	0.35	0.35	0.34	0.33	0.32	0.31	0.31	0.30
DistSubs	1.26	1.23	1.21	1.18	1.16	1.12	1.10	1.07	1.05	1.03
Dist Line & Cable	3.50	3.43	3.36	3.30	3.23	3.13	3.05	2.98	2.92	2.86
Zone Subs	0.61	0.60	0.59	0.58	0.57	0.55	0.53	0.52	0.51	0.50
Sub Transm.	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
SCADA	0.19	0.19	0.18	0.18	0.18	0.17	0.17	0.16	0.16	0.16

8.2.2.1 INDIRECT NETWORK OPEX

Figure 8.7 and Table 8.10 gives our SONS opex for the planning period.

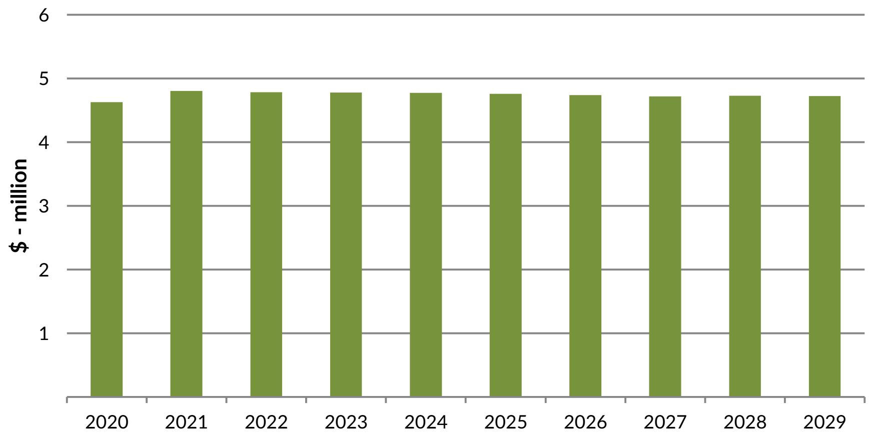


Figure 8.7 SONS opex for the planning period

Table 8.10 SONS opex for the planning period

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
4.63	4.80	4.78	4.78	4.77	4.76	4.74	4.72	4.73	4.72

This expenditure category remains fairly constant over the planning period. We believe that after the restructuring 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.

8.2.2.2 NON-NETWORK OPEX

Figure 8.8 and Table 8.11 gives the Business Support opex for the planning period.

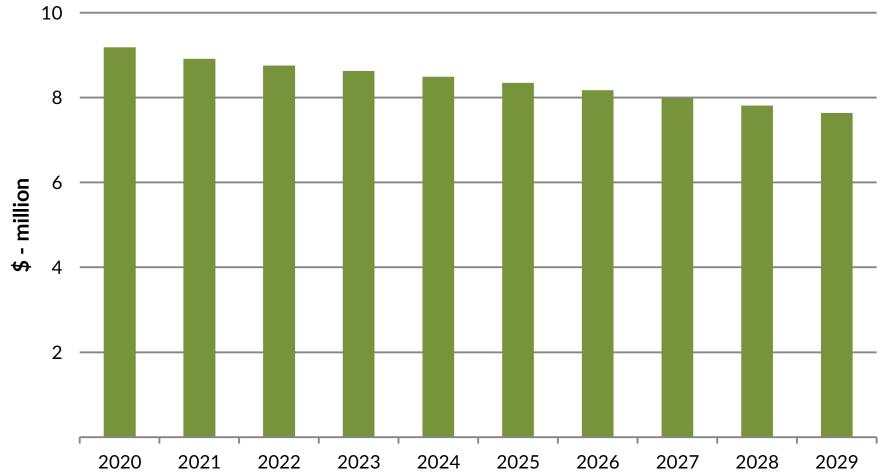


Figure 8.8 Business Support opex for the planning period

This budget category covers all staff and operational costs for the following teams and departments:

- Executive management team
- Human resources and administration teams
- Finance / accounting team and Commercial / regulatory teams
- Property / purchasing and Information technology teams

Table 8.11 Business Support opex for the planning period

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
9.18	8.91	8.75	8.62	8.49	8.35	8.17	7.98	7.81	7.64

8.3 PLANNING PERIOD EXPENDITURE FORECAST

Table 8.12 Total expenditure for the planning period 2019 to 2029 ('000)

Expenditure Category	Actual	Forecast										
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital expenditure												
Customer connections	3,798	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Growth	6,859	2,367	1,072	2,927	2,921	2,970	870	2,670	720	720	720	720
Replacements & Renewal	5,811	8,460	8,045	10,614	11,194	9,052	10,052	7,752	7,302	7,339	7,400	7,400
Relocations	2,027	620	350	500	500	810	1,000	1,000	1,000	1,000	1,625	1,000
Reliability, safety & environment	798	1,560	1,391	981	941	818	818	668	918	681	669	970
Subtotal – Network capex	**19,293**	**15,007**	**12,858**	**17,022**	**17,556**	**15,650**	**14,740**	**14,090**	**11,940**	**11,740**	**12,414**	**12,090**
Non-network capex	12,270	1,583	2,842	817	252	389	404	334	344	224	389	284
TOTAL CAPEX	**31,563**	**16,590**	**15,700**	**17,839**	**17,808**	**16,039**	**15,144**	**14,424**	**12,284**	**11,964**	**12,803**	**12,374**
Operational expenditure												
Service interruptions & emergencies	1,748	1,408	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750
Vegetation	431	598	800	800	800	800	800	720	700	680	660	660
Routine maintenance	2,520	3,103	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
Replacement & renewal	701	301	700	700	700	700	700	700	700	700	700	700
Subtotal – Network opex	**5,400**	**5,410**	**5,950**	**5,950**	**5,950**	**5,950**	**5,950**	**5,870**	**5,850**	**5,830**	**5,810**	**5,810**
Non-network opex	11,771	11,706	13,812	13,715	13,533	13,403	13,261	13,101	12,908	12,702	12,534	12,358
TOTAL OPEX	17,171	17,116	19,762	19,665	19,483	19,353	19,211	18,971	18,758	18,532	18,344	18,168
Total expenditure on assets	**48,734**	**33,706**	**35,462**	**37,504**	**37,292**	**35,392**	**34,355**	**33,395**	**31,042**	**30,496**	**31,147**	**30,542**

APPENDICES

A.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)
AMI	—	Advanced Meter Interface
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 Substation
CD2	—	Clandeboye No.2 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 Zone Substation
GWh	—	Giga Watt hours
GXP	—	Grid Exit Point
HNT	—	Hunt Street zone substation
HV	—	High Voltage
Hz	—	Hertz (a measure of frequency)
ICP	—	Installation Control Point
ICT	—	Information and Communications Technology
IED	—	Intelligent Electronic Device
ID	—	Information Disclosure

kV	—	kilo Volt
kVA	—	kilo Volt Ampere
LV	—	Low Voltage
MDC	—	Mackenzie District Council
MSB	—	Main Switch Board
MVA	—	Mega Volt Ampere
MW	—	Mega Watt
N-1	—	Reliability measure, where n systems can lose 1 element and still function normally
NSP	—	Network Supply Points
NST	—	North Street zone 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
SDW	—	Seadown zone substation (proposed)
SEL	—	Schweitzer Engineering Laboratories
SIE	—	System Interruptions and Emergencies
SONS	—	System Operations and Network Support
STU	—	Studholme grid exit point
TDC	—	Timaru District Council
TEK	—	Tekapo Village zone substation
TIM	—	Timaru grid exit point/step-up zone substation
TKA	—	Tekapo grid exit point
TMED	—	Threshold major event days
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

A.2 Disclosure schedules

A.2.1 SCHEDULE 11A

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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												
7		*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 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**	**31 Mar 29**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	2,000	2,040	2,081	2,122	2,165	2,208	2,252	2,297	2,343	2,390	2,438
11	System growth	2,367	1,093	3,045	3,100	3,215	961	3,007	827	844	860	878
12	Asset replacement and renewal	8,460	8,206	11,043	11,879	9,798	11,098	8,730	8,388	8,599	8,844	9,021
13	Asset relocations	620	357	520	531	877	1,104	1,126	1,149	1,172	1,942	1,219
14	Reliability, safety and environment:											
15	Quality of supply	975	639	655	696	723	738	752	767	798	800	756
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	585	780	365	302	162	166	-	287	-	-	427
18	**Total reliability, safety and environment**	1,560	1,419	1,021	999	885	903	752	1,054	798	800	1,182
19	**Expenditure on network assets**	15,007	13,115	17,710	18,631	16,940	16,274	15,868	13,715	13,755	14,836	14,738
20	Expenditure on non-network assets	1,583	2,899	850	268	422	446	376	395	262	465	346
21	**Expenditure on assets**	16,590	16,014	18,560	18,898	17,362	16,720	16,244	14,110	14,018	15,301	15,084
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	2,000	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**	14,590	14,014	16,560	16,898	15,362	14,720	14,244	12,110	12,018	13,301	13,084
28												
29	Assets commissioned	13,131	14,072	14,846	16,922	13,802	14,808	12,731	12,412	10,515	13,474	11,603
30		*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 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**	**31 Mar 29**
32		**$000 (in constant prices)**										
33	Consumer connection	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
34	System growth	2,367	1,072	2,927	2,921	2,970	870	2,670	720	720	720	720
35	Asset replacement and renewal	8,460	8,045	10,614	11,194	9,052	10,052	7,752	7,302	7,339	7,400	7,400
36	Asset relocations	620	350	500	500	810	1,000	1,000	1,000	1,000	1,625	1,000
37	Reliability, safety and environment:											
38	Quality of supply	975	626	630	656	668	668	668	668	681	669	620
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	585	765	351	285	150	150	-	250	-	-	350
41	**Total reliability, safety and environment**	1,560	1,391	981	941	818	818	668	918	681	669	970
42	**Expenditure on network assets**	15,007	12,858	17,022	17,556	15,650	14,740	14,090	11,940	11,740	12,414	12,090
43	Expenditure on non-network assets	1,583	2,842	817	252	389	404	334	344	224	389	284
44	**Expenditure on assets**	16,590	15,700	17,839	17,808	16,039	15,144	14,424	12,284	11,964	12,803	12,374
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											
49	Research and development											
50												

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52	for year ended	**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**	**31 Mar 29**
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	40	81	122	165	208	252	297	343	390	438
55	System growth	-	21	118	179	245	91	337	107	124	140	158
56	Asset replacement and renewal	-	161	429	685	746	1,046	978	1,086	1,260	1,444	1,621
57	Asset relocations	-	7	20	31	67	104	126	149	172	317	219
58	Reliability, safety and environment:											
59	Quality of supply	-	13	25	40	55	70	84	99	117	131	136
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	15	14	17	12	16	-	37	-	-	77
62	**Total reliability, safety and environment**	-	28	40	58	67	85	84	136	117	131	212
63	**Expenditure on network assets**	-	257	688	1,075	1,290	1,534	1,778	1,775	2,015	2,422	2,648
64	Expenditure on non-network assets	-	57	33	15	32	42	42	51	38	76	62
65	**Expenditure on assets**	-	314	721	1,090	1,322	1,576	1,820	1,826	2,054	2,498	2,710
66												

11a(ii): Consumer Connection

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
69	*Consumer types defined by EDB**	**$000 (in constant prices)**					
70	Low User Charge	100	100	100	100	100	100
71	015	280	280	280	280	280	280
72	360	240	240	240	240	240	240
73	Assessed	460	460	460	460	460	460
74	TOU 400V	920	920	920	920	920	920
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	2,000	2,000	2,000	2,000	2,000	2,000
77	*less* Capital contributions funding consumer connection	1,500	1,500	1,500	1,500	1,500	1,500
78	**Consumer connection less capital contributions**	500	500	500	500	500	500

11a(iii): System Growth

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
80	Subtransmission	-	-	-	-	-	-
81	Zone substations	1,570	2	1,702	2,201	2,200	200
82	Distribution and LV lines	-	265	-	-	-	-
83	Distribution and LV cables	300	300	300	300	300	300
84	Distribution substations and transformers	247	120	120	120	120	120
85	Distribution switchgear	150	235	150	150	150	150
86	Other network assets	100	150	655	150	200	100
87	**System growth expenditure**	2,367	1,072	2,927	2,921	2,970	870
88	*less* Capital contributions funding system growth	300	300	300	300	300	300
89	**System growth less capital contributions**	2,067	772	2,627	2,621	2,670	570
90							

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24

93 11a(iv): Asset Replacement and Renewal

Row			$000 (in constant prices)					
94		Subtransmission	344	100	200	-	-	-
95		Zone substations	855	555	3,800	3,900	1,700	2,700
96		Distribution and LV lines	3,714	3,870	4,234	4,664	4,652	4,652
97		Distribution and LV cables	800	700	300	300	550	550
98		Distribution substations and transformers	1,455	1,770	1,600	1,550	1,550	1,550
99		Distribution switchgear	542	130	-	-	-	-
100		Other network assets	750	920	480	780	600	600
101		**Asset replacement and renewal expenditure**	8,460	8,045	10,614	11,194	9,052	10,052
102	*less*	Capital contributions funding asset replacement and renewal	200	200	200	200	200	200
103		**Asset replacement and renewal less capital contributions**	8,260	7,845	10,414	10,994	8,852	9,852
104								

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24

107 11a(v): Asset Relocations

Row			$000 (in constant prices)					
108		*Project or programme**						
109		O/H to U/G conversions	620	350	500	500	810	1,000
110		[Description of material project or programme]						
111		[Description of material project or programme]						
112		[Description of material project or programme]						
113		[Description of material project or programme]						
114		**include additional rows if needed*						
115		All other project or programmes - asset relocations						
116		**Asset relocations expenditure**	620	350	500	500	810	1,000
117	*less*	Capital contributions funding asset relocations						
118		**Asset relocations less capital contributions**	620	350	500	500	810	1,000
119								

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24

122 11a(vi): Quality of Supply

Row			$000 (in constant prices)					
123		*Project or programme**						
124		New ABSs & automated devices	120	120	120	120	120	120
		New RMUs		100	100	100	100	100
125		Reclosers New	300	300	300	300	300	300
126		Mobile sub/gen site preparations	250	-	-	-	-	-
127		SCADA & pole top equipment automation (e.g. reclos	160	50	50	100	100	100
		Motorised LBS	85	-	-	-	-	-
128		Second 11 kV AMS connection at TEK	60	-	-	-	-	-
129		**include additional rows if needed*						
130		All other projects or programmes - quality of supply		56	60	36	48	48
131		**Quality of supply expenditure**	975	626	630	656	668	668
132	*less*	Capital contributions funding quality of supply						
133		**Quality of supply less capital contributions**	975	626	630	656	668	668
134								

11a(vii): Legislative and Regulatory

		for year ended	Current Year CY 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
	*Project or programme**	$000 (in constant prices)						
	[Description of material project or programme]							
	[Description of material project or programme]							
	[Description of material project or programme]							
	[Description of material project or programme]							
	[Description of material project or programme]							
	**include additional rows if needed*							
	All other projects or programmes - legislative and regulatory							
	Legislative and regulatory expenditure		-	-	-	-	-	-
less	Capital contributions funding legislative and regulatory							
	Legislative and regulatory less capital contributions		-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

		for year ended	Current Year CY 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
	*Project or programme**	$000 (in constant prices)						
	New RMUs		100	-	-	-	-	-
	Abloy locks		250	100	100	100	100	-
	SCADA Master Station Modules		30	50	50	100	50	150
	[Description of material project or programme]							
	[Description of material project or programme]							
	**include additional rows if needed*							
	All other projects or programmes - other reliability, safety and environment		205	615	201	85	-	-
	Other reliability, safety and environment expenditure		585	765	351	285	150	150
less	Capital contributions funding other reliability, safety and environment		-					
	Other reliability, safety and environment less capital contributions		585	765	351	285	150	150

11a(ix): Non-Network Assets

	for year ended	Current Year CY 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
Routine expenditure							
*Project or programme**	$000 (in constant prices)						
IT		151	957	616	148	180	120
Equipment		277	615	201	104	104	104
Vehicles		-	170	-	-	105	180
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other projects or programmes - routine expenditure		-					
Routine expenditure		428	1,742	817	252	389	404
Atypical expenditure							
*Project or programme**							
Property		1,155	1,100	-	-	-	-
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other projects or programmes - atypical expenditure		-					
Atypical expenditure		1,155	1,100	-	-	-	-
Expenditure on non-network assets		1,583	2,842	817	252	389	404

A.2.2 SCHEDULE 11B

Company Name **Alpine Energy Limited**
AMP Planning Period **1 April 2019 – 31 March 2029**

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 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**	**31 Mar 29**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,408	1,785	1,821	1,857	1,894	1,932	1,971	2,010	2,050	2,091	2,133
11	Vegetation management	598	816	832	849	866	883	811	804	797	789	805
12	Routine and corrective maintenance and inspection	3,103	2,754	2,809	2,865	2,923	2,981	3,041	3,101	3,163	3,227	3,291
13	Asset replacement and renewal	301	714	728	743	758	773	788	804	820	837	853
14	**Network Opex**	5,410	6,069	6,190	6,314	6,440	6,569	6,611	6,720	6,831	6,943	7,082
15	System operations and network support	4,048	4,721	4,997	5,074	5,172	5,270	5,356	5,440	5,528	5,649	5,754
16	Business support	7,657	9,367	9,271	9,288	9,335	9,372	9,398	9,387	9,354	9,330	9,310
17	**Non-network opex**	11,706	14,088	14,269	14,362	14,507	14,642	14,754	14,827	14,882	14,979	15,064
18	**Operational expenditure**	17,116	20,157	20,459	20,676	20,948	21,211	21,364	21,547	21,713	21,923	22,147

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 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**	**31 Mar 29**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,408	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750
23	Vegetation management	598	800	800	800	800	800	720	700	680	660	660
24	Routine and corrective maintenance and inspection	3,103	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
25	Asset replacement and renewal	301	700	700	700	700	700	700	700	700	700	700
26	**Network Opex**	5,410	5,950	5,950	5,950	5,950	5,950	5,870	5,850	5,830	5,810	5,810
27	System operations and network support	4,048	4,629	4,803	4,781	4,778	4,773	4,756	4,736	4,718	4,727	4,721
28	Business support	7,657	9,183	8,911	8,752	8,624	8,488	8,345	8,172	7,984	7,807	7,637
29	**Non-network opex**	11,706	13,812	13,715	13,533	13,403	13,261	13,101	12,908	12,702	12,534	12,358
30	**Operational expenditure**	17,116	19,762	19,665	19,483	19,353	19,211	18,971	18,758	18,532	18,344	18,168
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	250	249	249	249	249	249	249	249	249	249	249

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 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**	**31 Mar 29**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	35	71	107	144	182	221	260	300	341	383
43	Vegetation management	-	16	32	49	66	83	91	104	117	129	145
44	Routine and corrective maintenance and inspection	-	54	109	165	223	281	341	401	463	527	591
45	Asset replacement and renewal	-	14	28	43	58	73	88	104	120	137	153
46	**Network Opex**	-	119	240	364	490	619	741	870	1,001	1,133	1,272
47	System operations and network support	-	93	194	293	394	497	600	704	810	922	1,034
48	Business support	-	184	360	536	711	883	1,053	1,215	1,370	1,523	1,673
49	**Non-network opex**	-	276	554	828	1,105	1,380	1,653	1,919	2,180	2,445	2,706
50	**Operational expenditure**	-	395	794	1,193	1,595	2,000	2,393	2,789	3,181	3,579	3,979

A.2.3 SCHEDULE 12A

Company Name	Alpine Energy Limited
AMP Planning Period	1 April 2019 – 31 March 2029

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	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					Asset condition at start of planning period (percentage of units by grade)							
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	-	-	10.70%	53.60%	35.70%	-	3	-
11	All	Overhead Line	Wood poles	No.	6.00%	19.00%	23.00%	24.00%	28.00%	-	3	6.00%
12	All	Overhead Line	Other pole types	No.							[Select one]	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	2.20%	31.70%	27.50%	38.60%	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							[Select one]	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	13.00%	87.00%	-	4	-
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.	-	9.00%	17.00%	17.00%	57.00%	-	3	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	100.00%	-	4	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	18.20%	16.40%	15.50%	3.60%	46.30%	-	2	5.00%
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.	-	-	5.80%	21.60%	72.60%	-	4	4.70%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	14.30%	-	85.70%	-	3	-
35												

36					Asset condition at start of planning period (percentage of units by grade)							
37												
38	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	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.	-	7.40%	29.60%	11.10%	51.90%	-	4	7.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.10%	32.80%	23.40%	14.30%	29.40%	-	3	1.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							[Select one]	
42	HV	Distribution Line	SWER conductor	km	-	100.00%	-	-	-	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.30%	0.30%	3.60%	5.20%	90.60%	-	3	0.50%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	73.00%	27.00%	-	3	-
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.	2.10%	-	4.30%	17.00%	76.60%	-	3	3.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.							[Select one]	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	17.30%	9.20%	6.70%	14.80%	52.00%	-	2	5.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	18.00%	18.00%	64.00%	-	3	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.00%	18.00%	15.00%	27.00%	38.00%	-	3	2.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.20%	13.70%	27.90%	30.60%	27.60%	-	3	1.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.80%	9.00%	29.80%	29.50%	30.90%	-	3	1.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	3.00%	97.00%	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.							[Select one]	
55	LV	LV Line	LV OH Conductor	km	0.10%	4.00%	54.50%	34.10%	7.30%	-	3	1.00%
56	LV	LV Cable	LV UG Cable	km	0.09%	2.15%	21.15%	47.37%	29.24%	-	2	1.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km							[Select one]	
58	LV	Connections	OH/UG consumer service connections	No.							[Select one]	
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	4.00%	3.00%	-	17.00%	76.00%	-	4	4.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	9.00%	1.00%	11.00%	79.00%	-	2	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	17.65%	17.65%	64.70%	-	3	-
62	All	Load Control	Centralised plant	Lot	8.00%	-	17.00%	25.00%	50.00%	-	3	8.00%
63	All	Load Control	Relays	No.	4.00%	-	-	20.00%	76.00%	-	4	4.00%
64	All	Civils	Cable Tunnels	km					100.00%	-	4	-

A.2.4 **SCHEDULE 12B**

Company Name **Alpine Energy Limited**
AMP Planning Period **1 April 2019 – 31 March 2029**

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
9	Albury (ABY)	6	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
10	Balmoral (BML)	-	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
11	Bells Pond (BPD)	15	20	N-1	-	75%	20	123%	Transformer	T1 installed FY18/19, T2 to be upgraded to relieve constraint
12	Clandeboye 1 (CD1)	14	20	N-1	-	70%	30	69%	Transformer	Upgrade transformers to relieve constraint
13	Clandeboye 2 (CD2)	15	25	N-1	-	60%	25	99%	No constraint within +5 years	Meets Alpine Security standard due to sufficient 11 kV backup
14	Cooney's Road (CNR)	4	-	N	1.8/0.8/0.6*	-	-	-	No constraint within +5 years	Meets Alpine security standard
15	Fairlie (FLE)	3	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
16	Geraldine (GLD)	7	-	N	-	-	8	104%	No constraint within +5 years	Options being assessed to upgrade installed firm capacity
17	Haldon Lilybank (HLB)	-	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
18	Pareora (PAR)	9	15	N-1	-	60%	15	63%	No constraint within +5 years	Meets Alpine security standard
19	Pleasant Point (PLP)	5	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
20	Rangitata (RGA)	11	10	N-1	-	110%	10	118%	Subtransmission circuit	Line capacity constraint, sufficient 11 kV backup in place
21	Studholme (STU)	15	10	N-1	-	150%	10	204%	Transpower	Transpower two 11 MVA transformers, load shedding/shift required
22	Tekapo Village (TEK)	4	-	N	-	-	15	63%	Subtransmission circuit	Options being assessed to upgrade installed firm capacity
23	Temuka (TMK)	14	25	N-1	-	56%	25	64%	No constraint within +5 years	Meets Alpine Security standard
24	Timaru 11/33 kV (TIM)	17	25	N-1 Switched	-	68%	25	74%	No constraint within +5 years	Meets Alpine Security standard
25	Twizel Village (TVS)	4	-	N	-	-	6	67%	No constraint within +5 years	Options being assessed to upgrade installed firm capacity
26	Unwin Hut (UHT)	1	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
27	[Zone Substation_19]					-			[Select one]	
28	[Zone Substation_20]					-			[Select one]	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

A.2.5 SCHEDULE 12C

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
11	*Consumer types defined by EDB**							
12	Low Charge		11,218	12,324	13,540	14,876	16,344	17,956
13	Low Uncontrolled		40	44	48	53	58	64
14	015		20,001	20,441	20,891	21,350	21,820	22,300
15	015 Uncontrolled		78	80	82	83	85	87
	360		1,298	1,360	1,424	1,492	1,563	1,637
	360 Uncontrolled		29	31	34	37	41	44
	Assessed		1,704	1,758	1,813	1,870	1,929	1,989
	TOU 400V		142	142	143	143	144	144
	TOU 11kV		9	9	9	9	9	9
16	IND		12	12	12	12	12	12
17	**Connections total**		34,531	36,201	37,996	39,925	42,005	44,242
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		369	442	515	588	660	733
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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
25	GXP demand		146	149	152	155	158	161
26	*plus* Distributed generation output at HV and above		3	3	3	3	3	3
27	**Maximum coincident system demand**		149	152	155	158	161	164
28	*less* Net transfers to (from) other EDBs at HV and above							
29	**Demand on system for supply to consumers' connection points**		149	152	155	158	161	164
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		791	807	822	838	855	871
32	*less* Electricity exports to GXPs		22	23	23	24	24	25
33	*plus* Electricity supplied from distributed generation		38	39	40	40	41	42
34	*less* Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**		807	823	839	854	872	888
36	*less* Total energy delivered to ICPs		777	792	807	823	839	855
37	**Losses**		30	31	32	31	33	33
38								
39	**Load factor**		62%	62%	62%	62%	62%	62%
40	**Loss ratio**		3.7%	3.8%	3.8%	3.6%	3.8%	3.7%

A.2.6 SCHEDULE 12D

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref								
8			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		39.8	39.8	39.8	39.8	39.8	39.8
12	Class C (unplanned interruptions on the network)		93.0	93.0	93.0	93.0	93.0	93.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.39	0.39	0.39	0.39	0.39	0.39
15	Class C (unplanned interruptions on the network)		0.91	0.91	0.91	0.91	0.91	0.91

A.2.7 SCHEDULE 13

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
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.
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.
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 6 of the AMP.
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?	3	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. Chapter 4 and 6 of the AMP.	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. Draft fleet strategies for all major asset types have been developed.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	Copies of our AMP are circulated to our subsidiary NETcon and to other large contractors. We do not provide copies to customers but will do so on request. Specific accountabilities for the AMP are detailed in all relevant staff position. Communications plan has been developed and is being reviewed.	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.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2	Alliance Agreement with NETcon Position descriptions Standard forms of contract ie. NZ 3910	All asset management related position descriptions details requirements of the role in the asset management process. 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 Alliance Agreement with our in-house service provider details of engagement and delivery.
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)	3	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.	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. We maintain a competency register for all service providers. We meet every two weeks with main service providers to measure progress of the workplan wrt physical completion.
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.	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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance
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.	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. We have drafted a communications plan which is being reviewed.
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.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	**2**	1.Schedule 13 Senior management meeting 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. 9. Communication plan in draft format and being reviewed.	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 .
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?	**3**	1. NETcon Alliance Agreement 2. Contracts for delivery in accordance with AS/NZS 3910. 3. TechnologyOne ERP software generate automated reports and documented processes for all asset managegement activities. 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. Fortnightly meetings with service providers reviews defects and red tag pole register.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance
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)?	3	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. 4. Position descriptions. 5. Draft succession plan/strategy under development.	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.
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 Access 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.
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. 6. Personal development plans in place.	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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance
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?	3	1. Asset Management Policy 2. AMP 3. NETcon Alliance Agreement and meetings 4. Senior management job descriptions and meetings. 5. Draft communications plan developed and under review.	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.
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.
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. Approved 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.
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. 5. Asset audit project approved to verify, complete and quality controlll data in EAM systems.	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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance
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 requirements based on the process identified by the BPM project. We are establishing a review process.
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.
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.
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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance
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. 7. Draft fleet strategies in place for all high value/critical assets.	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. We have developed maintenance schedules based on maintenance strategies for all main maintenance activities.
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?	3	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. 7. Maintenance standards & inspection schedules in EAM. 8. Outage management processes developed and in use.	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.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	1. AMP, chapter 6. 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. Our EAM is now in place and a project to verify and improve data quality is planned for 2019 through to 2021. Once complete we would expect an increase in score. We are yet to formalise or determine measures to review our processes.
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. 8. Communication plan developed and under review.	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. We have developed a GIS solution to record asset failures during network emergencies that is widely visible throughout the organisation. This is updated in real time as work progresses.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance
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.
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?	2	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. 6. Defect reporting and actions as well as red tag pole reporting and mitigation.	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. ICAM investigation process implemented and used extensively.
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. We maintain customer complaints register. Monthly report to board re assets risks.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	1. 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. 5. CIGRE & Engineering NZ affiliation and working group participation.	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.

A.2.8 SCHEDULE 14

Company name: Alpine Energy Limited

For Year Ended 31 March 2018

Schedule 14a - Mandatory Explanatory Notes of Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015))

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is part of the audited disclosure information, and so is not subject to the assurance requirements specified in Section 2.5.

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.

A.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 discussed in Appendix A.4.

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 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 A.3-1. Accountability for risk management includes ensuring that the necessary controls to modify the risks and control assurance activities are in place and are effective at all times.

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.

Table A.3-1 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.

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.

A.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 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.

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, or irrigators spraying into our 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.

A.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 A.3-2 lists the qualitative measures of likelihood we use in our risk assessment.

Table A.3-2 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 A.3-3 describes the qualitative measures of consequence or impact that we use in our risk assessment.

Table A.3-3 Measure of risk consequence

Con-sequence level	Insignifi-cant	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) under-utilised or stranded	Network asset (to the value of $100,000–$1 million) under-utilised or stranded	Network assets (to the value of $1 million–$5 million) under-utilised or stranded	Network assets (to the value of over $5 million) under-utilised or stranded
Reliability of supply	Unplanned outages (Class C): <1 SAIDI min or <40 ICP interrupt-tions 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 interrup-tions per event	Unplanned outages (Class C): 33<&<161 SAIDI mins or 1000<&<1500 ICP interrup-tions per event	Unplanned outages (Class C): >161 SAIDI mins or >1500 ICP interrup-tions 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 A.3-1 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 A.3-1 Network risk matrix

Based on the risk score, specific response and reporting requirements are determined. The requirements are described in Table A.3-4.

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 A.3-4 Response by risk level

Level of risk	Urgency for implementation of treatment	Authority for continued tolerance of	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][43] days of the identification to GM—Network (or such other period that is practical in the circumstances).	GM—Network	Advise GM—Network within 24 hours of identification, and the GM to advise CEO as soon as practicable after receiving advice and to include in next reporting cycle.
Medium	Action plan (if necessary) to be developed within [x] months of identification to the GM—Network (or such 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).

A.3.3 HIGH CONSEQUENCE LOW PROBABILITY RISKS

Our distribution network is built in a hierarchical structure with Transpower GXPs providing supply points for 33 kV sub-transmission and zone substation assets. The zone substations have multiple feeders that connect the 11 kV distribution lines. Distribution

[43] Where [x] days or months, the number is determined by the GM—Network to suit the circumstance.

lines traverse the region and support 11 kV assets and distribution level transformers, which break down into the LV networks and more than 31,000 individual connection points.

Failure of a hierarchy asset at the GXP 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.

Mitigating against high consequence low probability events at seven of our zone substations, we have procured and developed standby diesel generation plant and a mobile substation as described below.

- A mobile generator set (AMG) made up of two 810 kVA machines able to base load at 500 kW each or 1 MW in total. The machines can be used at 11 kV or 400 V to allow maintenance of distribution substations or provide small community back-up.
- A mobile substation (AMS) that connects at 33 kV and 11 kV with a 9 MVA rating. We are preparing all of our single transformer zone substations so that the mobile substation can be installed in parallel to allow the release of the zone substation for maintenance.

Zone substation transformers

Table A.3-5 details our high consequence / low probability risks as it relates the highest consequence risk category with 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 seven projects to enable us to deploy our mobile substation or our mobile diesel generation to these zone substations in the event of an emergency. Our Twizel zone substation is the only remaining zone substation (33/11 kV) with N security where we cannot deploy our mobile substation or generators. This will be addressed during the planned project to rebuild this substation.

Table A.3-5 Zone substation transformer risk analysis

Zone substation	Risk Category	Mitigated 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
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.

Notes:

* *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, Bells Pond, 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. This will result in a loss of all outgoing feeders, which is similar to the loss of a zone substation transformer and 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 A.3-5.

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 A.3-6. 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 A.3-6 Switchboard risk analysis

Zone/switching substation	Risk Category	Mitigated 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[44]	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.

The risks at the Clandeboye substations are mitigated as the site has a supply security level of N-1.

The two Pareora 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.

[44] This refers to the old switchboard for transformer #1

The Rangitata, Studholme, Temuka, and Pareora 11 kV switchboards are fitted with bus zone protection that 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 A.3-6 are an 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.

A.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. 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 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[45] event in the next 50 years is 30%[46]. 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 exacerbate 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 sandbagging 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.

A.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 still recognise 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 we obtain the maximum benefit from every dollar we invest or spend, it is necessary for all investment and expenditure to be evaluated on a standard basis. 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
- ensure that our maintenance on assets are appropriate and based on risk mitigation

[45] 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

[46] According to the GNS Science website.

Risk Management framework

Our Risk Management framework is intended to help us understand the risks and respond to these through appropriate mitigation.

All staff can, and are 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 as per our Risk Management Policy 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.

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.

A.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[47]. Some of our existing large and important substation buildings have been strengthened for seismic events.

With less than 10% of our sub-transmission 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.

[47] *Buildings* that are essential to post-disaster recovery or associated with hazardous facilities.

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.

A.4 Safety management system

This appendix outlines the safety management approach we employ for managing our network assets and activities. Our safety management framework is depicted in the figure below.

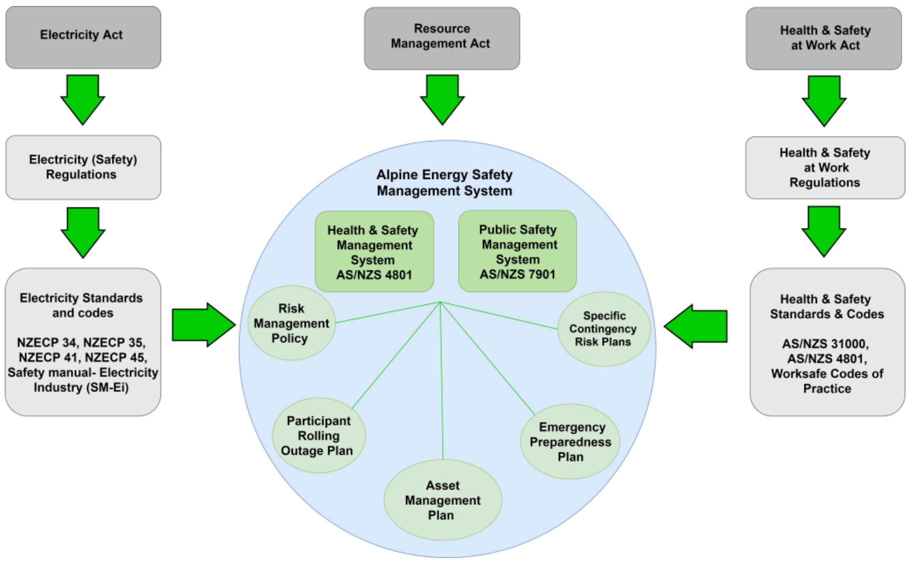


Figure A.4-1 Safety management framework

A.4.1 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 an 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.

A.4.2 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.

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 A.4-2 provides an example of our communication through print media.

Figure A.4-2 Example of print media communications

A.4-1 Media print example

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.

Public reporting via Snap Send Solve

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.

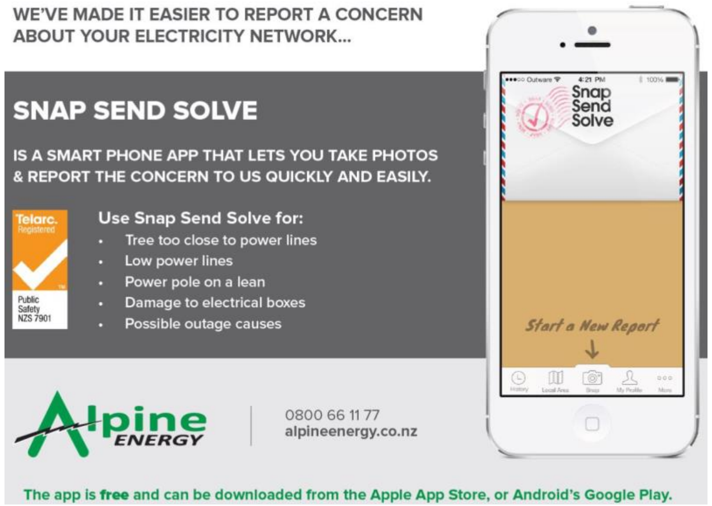


Figure A.4-3 Illustration of *Snap Send Solve* mobile app.

Free plans, Cable location and mark out

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 where practicable by 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.

A.4.3 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.

A.4.4 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 a 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.

Business continuity planning

Alpine House is constructed to Importance Level 4 standards.

We are well provisioned with standby generation, and our own communications pathways to support critical infrastructure.

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.

We are in the process of installing a bulk diesel fuel tank and dispenser in our yard to decrease our reliance on external fuel sites.

We have provisioned non-perishable food and water for 200 staff for seven days.

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 proactively. Our communication responsibilities are:

- Chief Executive Officer: Board of Directors, 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 consumers.

Responsibilities for communications are detailed in Section 4.2 of the Participant Rolling Outage Plan.

Outage information

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.

A.4.5 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).

A.4.6 SPECIFIC CONTINGENCY PLANS

Specific contingency plans for the restoration of supply to essential services and 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 33 kV zone substation, we have a specific plan developed jointly with Transpower to ensure electrical supply continuity to the Fonterra Clandeboye dairy factory.

A.4.7 CIVIL DEFENCE EMERGENCY MANAGEMENT

In the event of a Civil Defence Emergency, nominated staff members are sent to man the local district council's Civil Defence Emergency Operations Centre. A dedicated radio telephone link is installed in the Timaru District Council's Emergency Operations Centre for direct communication with our control room.

The Canterbury Lifelines Utilities Group[48] 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 annual regional exercises such as 'Pandora', 'Olaf', 'Ripahapa' and 'Tongaroa'. Lessons learnt from these exercises are used to enhance our current emergency response planning.

Delegates from board and executive management level have also attended recent workshops where the South Island regional preparedness for a magnitude 8 earthquake in the Alpine Fault line was discussed.

This has led to a specific emergency plan being developed for an earthquake of magnitude 8 or above occurring on the Alpine Fault.

[48] We were a founding member of the South Canterbury Lifelines Group, which amalgamated with the Canterbury Lifelines Utilities Group.

A.5 Demand forecasts

This appendix sets out the 10 year demand forecasts for Transpower's GXPs and our zone substations.

A.5.1 DEMAND FORECAST FOR THE ALBURY REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)
Albury GXP	20.00	-	11.30	4.95	5.02	5.08	5.15	5.22	5.28	5.35	5.42	5.48	5.55	5.62
Albury zone substation	7.50	-	7.61	6.85	6.94	7.03	7.13	7.22	7.32	7.42	7.52	7.62	7.72	7.82
Fairlie zone substation	6.25	-	5.38	3.08	3.12	3.16	3.20	3.24	3.29	3.33	3.37	3.42	3.47	3.51

A.5.2 DEMAND FORECAST FOR THE BELLS POND REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)
Bell Pond GXP	60.00	20.00	68.59	15.00	16.27	22.53	23.80	25.07	26.33	27.60	28.87	30.14	31.40	32.67
Bell Pond zone substation	60.00	20.00	30.06	15.63	16.26	21.91	22.78	23.69	24.64	25.63	26.65	27.72	28.83	29.98
Cooneys road zone substation	15.00		15.30	4.19	4.19	9.19	9.19	9.19	9.19	9.19	9.19	9.19	9.19	9.19

A.5.3 DEMAND FORECAST FOR THE STUDHOLME (WAIMATE) REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)
Studholme GXP	20.00	10.00	19.81	17.38	18.00	18.27	18.54	18.81	19.07	19.34	19.61	19.88	20.15	20.42

A.5.4 DEMAND FORECAST FOR THE TEKAPO REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)
Tekapo GXP	10.00	-	10.46	5.02	6.40	8.59	9.86	10.60	10.76	10.90	11.02	11.15	11.27	11.39
Tekapo zone substation	6.25	-	5.18	4.30	5.23	7.34	8.56	9.27	9.39	9.50	9.60	9.69	9.79	9.89
Haldon-Lily Bank zone substation	1.00	-	1.00	0.50	0.50	0.51	0.51	0.52	0.52	0.53	0.53	0.54	0.54	0.55
Balmoral zone substation	0.60	-	0.38	0.57	0.70	0.77	0.99	1.03	1.08	1.12	1.14	1.16	1.19	1.21
Unwin Hut Zone Substation	1.50		2.86	0.87	0.87	0.88	0.88	0.89	0.89	0.90	0.90	0.91	0.91	0.91

A.5.5 DEMAND FORECAST FOR THE TEMUKA REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)
Temuka GXP	108.00	54.00	93.36	70.55	76.43	81.43	83.06	84.96	86.58	88.21	89.83	91.46	93.22	94.85
Temuka zone substation	50.00	25.00	40.50	14.84	15.26	15.69	16.14	16.60	17.07	17.55	18.05	18.56	19.09	19.63

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)
Geraldine zone substation	7.00		10.34	7.16	7.46	7.67	7.89	8.11	8.34	8.58	8.82	9.07	9.33	9.59
Rangitata 1 zone substation	30.00	15.00	10.00	6.48	6.67	6.86	7.05	7.25	7.46	7.67	7.89	8.11	8.34	8.58
Rangitata 2 zone substation	30.00	10.00	12.06	4.44	4.57	4.70	4.83	4.97	5.11	5.25	5.40	5.55	5.71	5.87
Clandeboye 1 zone substation	40.00	20.00	40.46	15.57	19.37	20.57	20.57	20.57	20.57	20.57	20.57	20.57	20.57	20.57
Clandeboye 2 zone substation	50.00	25.00	48.11	22.26	22.61	24.65	24.65	24.65	24.65	24.65	24.65	24.65	24.65	24.65

A.5.6 DEMAND FORECAST FOR THE TIMARU REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)
Timaru GXP	141.00	94.00	93.81	69.02	70.71	71.14	71.58	72.01	72.44	72.87	73.30	73.74	74.17	74.60
Timaru zone substation	141.00	94.00	93.81	68.90	70.60	71.05	71.51	71.97	72.43	72.89	73.36	73.83	74.31	74.78
Alpine Timaru Step-up (ATM)	50.0	25.00	13.72	6.43	6.48	6.52	6.56	6.60	6.64	6.69	6.73	6.77	6.82	6.86

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)
Alpine Timaru Step-up (ATM_2)	50.0	25.00	13.72	10.93	11.00	11.07	11.15	11.22	11.29	11.36	11.43	11.51	11.58	11.66
Pleasant Point zone substation	6.25	-	5.29	5.00	5.03	5.06	5.09	5.12	5.16	5.19	5.22	5.26	5.29	5.33
Pareora zone substation	30.00	15.00	15.00	8.81	8.87	8.93	8.98	9.04	9.10	9.16	9.22	9.27	9.33	9.39
Grasmere zone substation	31.29	23.46	-31.44	28.13	28.31	28.50	28.68	28.86	29.05	29.23	29.42	29.61	29.80	29.99
North Street zone substation	30.89	15.44	-30.72	13.37	13.86	13.95	14.04	14.13	14.22	14.31	14.40	14.49	14.59	14.68
Hunt Street zone substation	22.46	16.85	-22.67	10.75	10.81	10.88	10.95	11.02	11.09	11.17	11.24	11.31	11.38	11.45

A.5.7 DEMAND FORECAST FOR THE TWIZEL REGION SUBSTATIONS

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)	2027 (MW)	2028 (MW)	2029 (MW)
Twizel GXP*	20	-	6.86	3.45	3.76	3.83	3.91	3.99	4.07	4.15	4.22	4.30	4.38	4.46
Twizel Village zone substation	6.25	-	6.25	3.61	3.70	3.78	3.86	3.95	4.04	4.13	4.22	4.31	4.41	4.51

A.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.

A.6.1 ALBURY REGION NETWORK CONFIGURATION

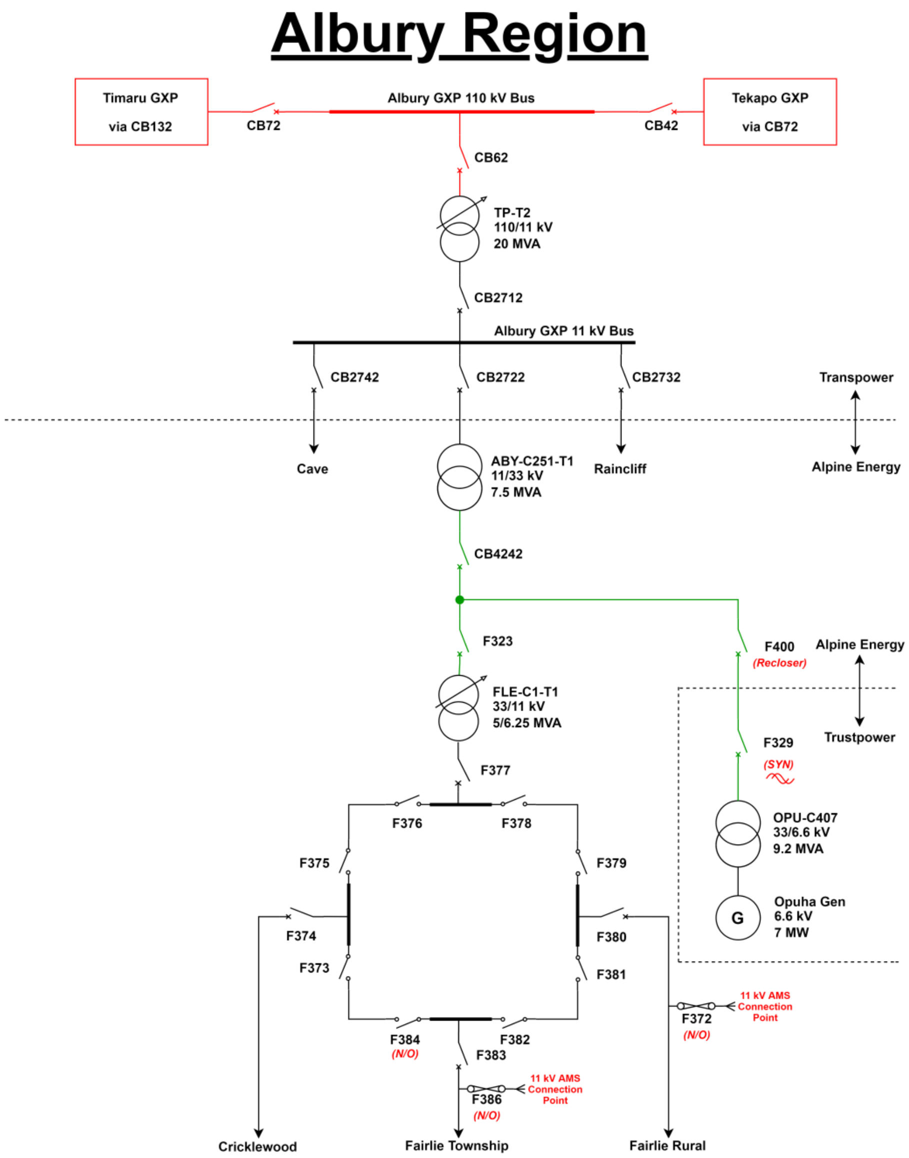
The Albury GXP is fed off the TIM–TKA 110 kV line and has a single 110/11 kV transformer connected to an 11 kV switchboard. The transformer was upgraded in 2017 from 6 to 20 MVA. These are Transpower assets.

The Albury GXP can 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 remaining circuit breaker feed into an 11/33 kV, 7.5 MVA step-up 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[49] (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).



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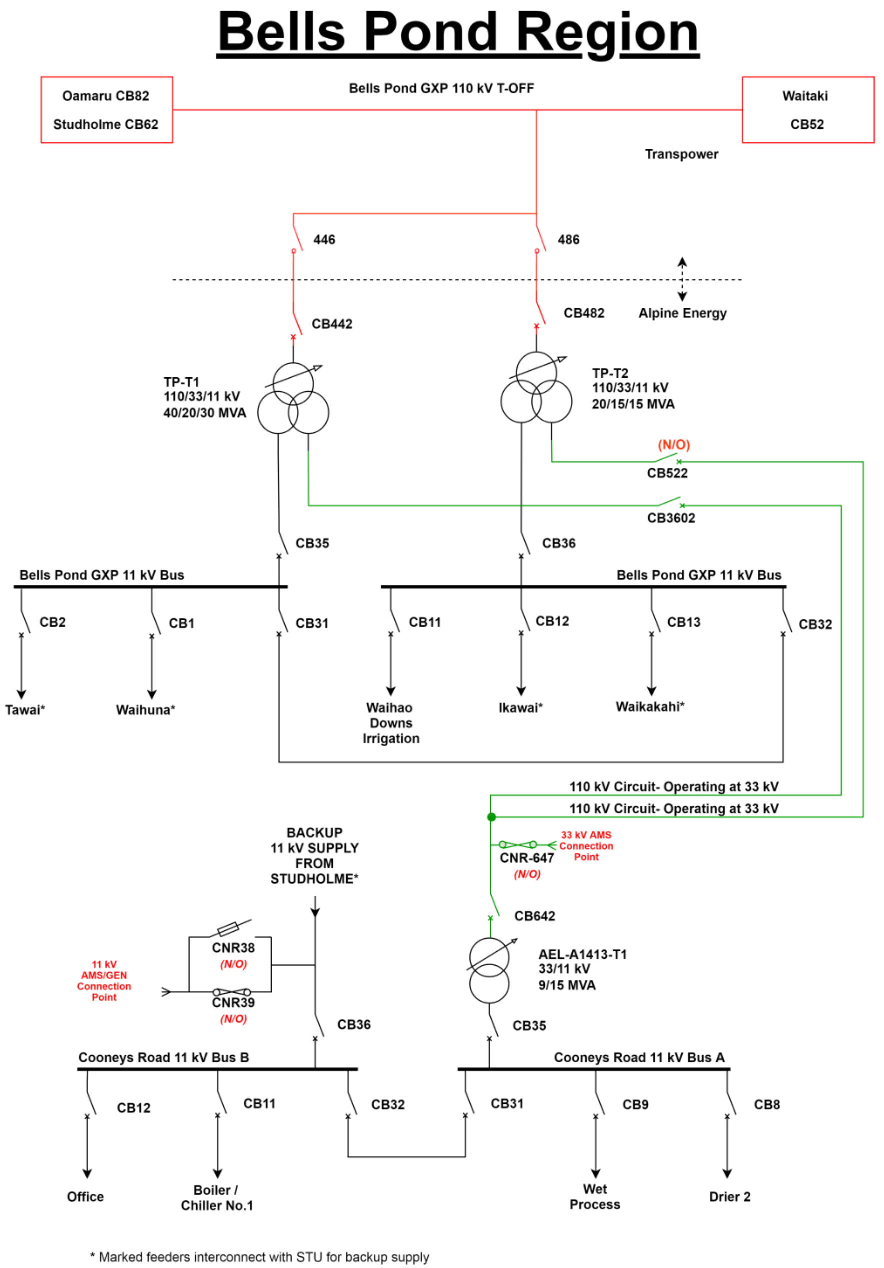
A.6.2 BELLS POND REGION NETWORK CONFIGURATION

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 five 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 from the power transformers at BPD supply 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 (to provide back supply up to 0.5 MVA).



A.6.3 STUDHOLME (WAIMATE) REGION NETWORK CONFIGURATION

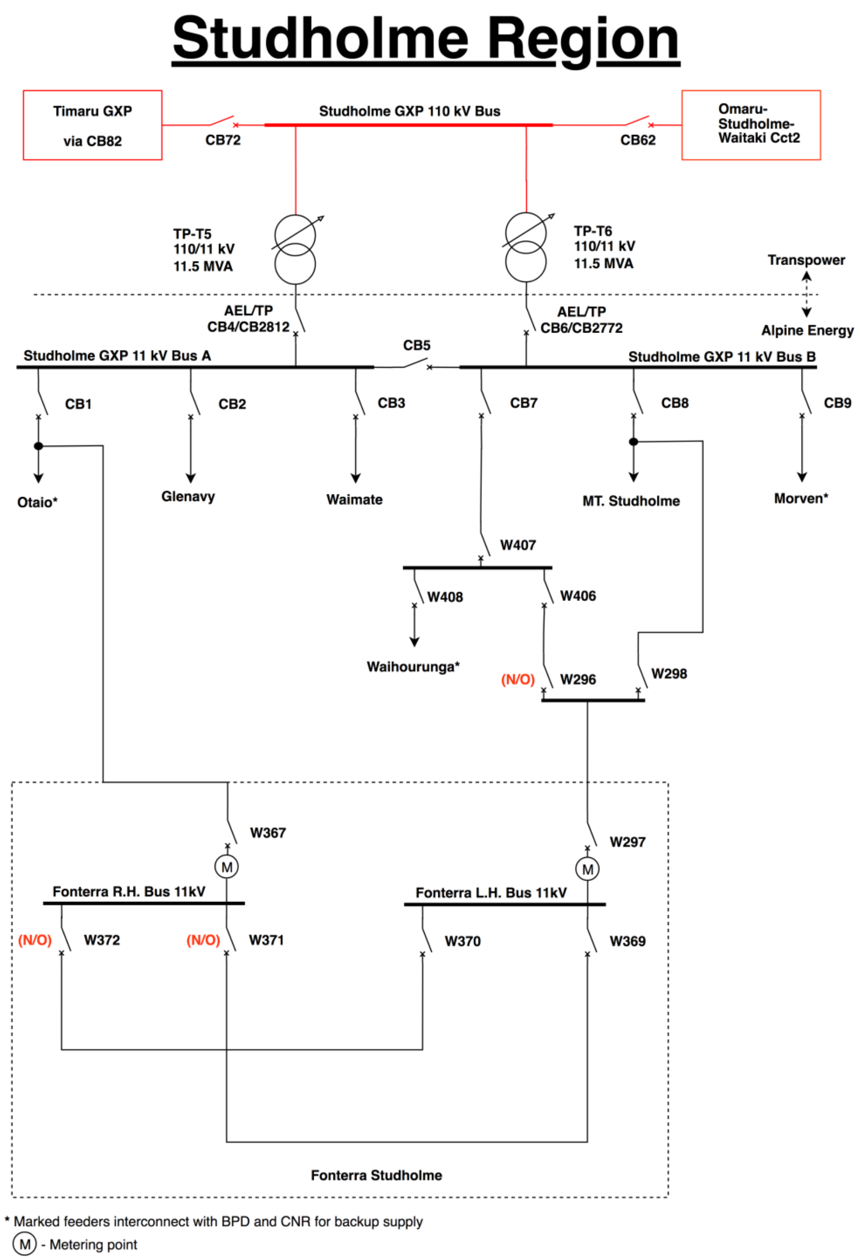
The Studholme GXP is supplied from the 110 kV transmission from Timaru and from Waitaki. The 110 kV system is normally split on a manually operated switch (STU DS76) from 30 April until 1 October. This means the Studholme GXP is supplied from Waitaki. During the dairy season this switch is run closed 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.



A.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 Tekapo-Albury-Timaru 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 and used successfully in 2019.

The Tekapo GXP can 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 Tekapo zone substation we have a 33 kV sub-transmission line to Glentanner and Unwin Hut.

At Glentanner there are 33/0.4 kV distribution transformers supplying consumers.

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 sub-transmission circuit.

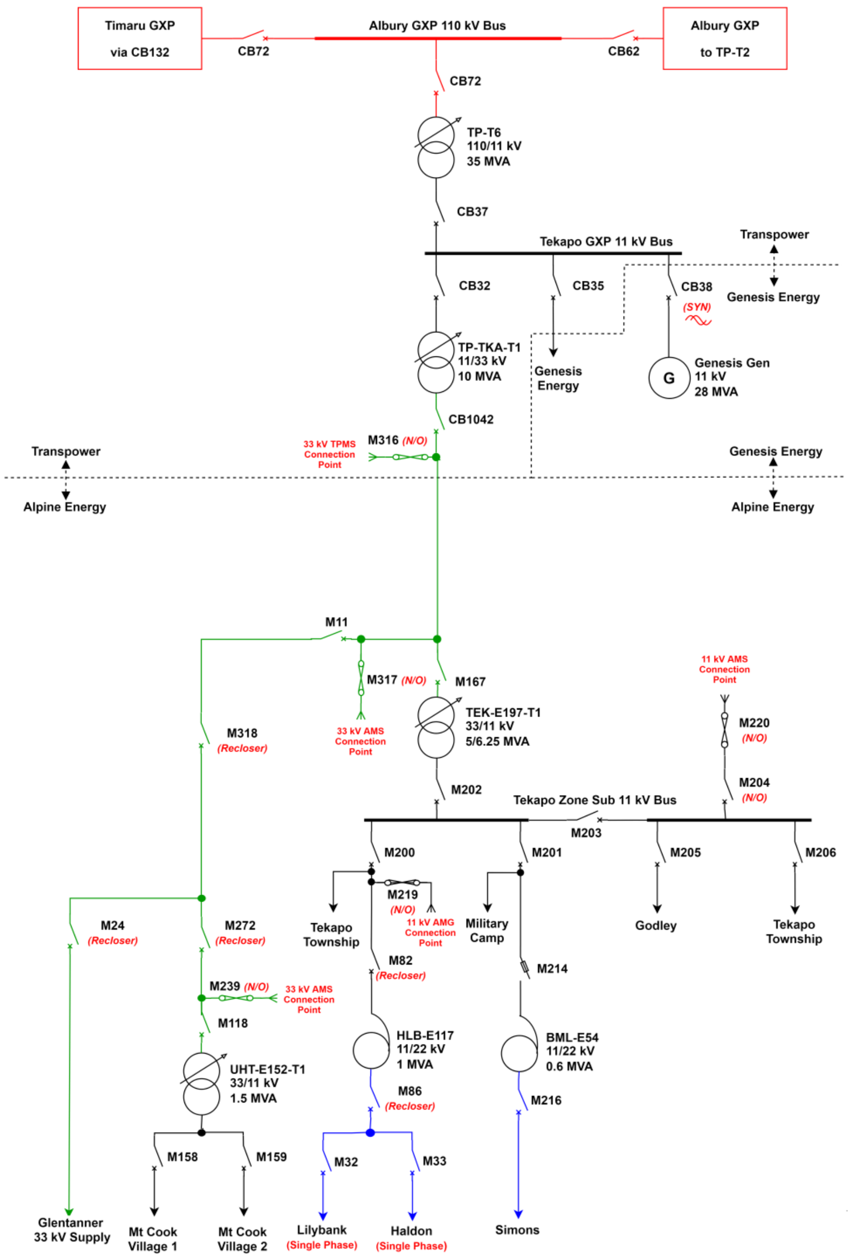
Connections for the mobile substation and standby/emergency diesel generation are available at the Tekapo zone substation.

The 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 Haldon-Lilybank 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



A.6.5 TEMUKA REGION NETWORK CONFIGURATION

The Temuka GXP is supplied by two 110 kV transmission lines from the Transpower Timaru substation.

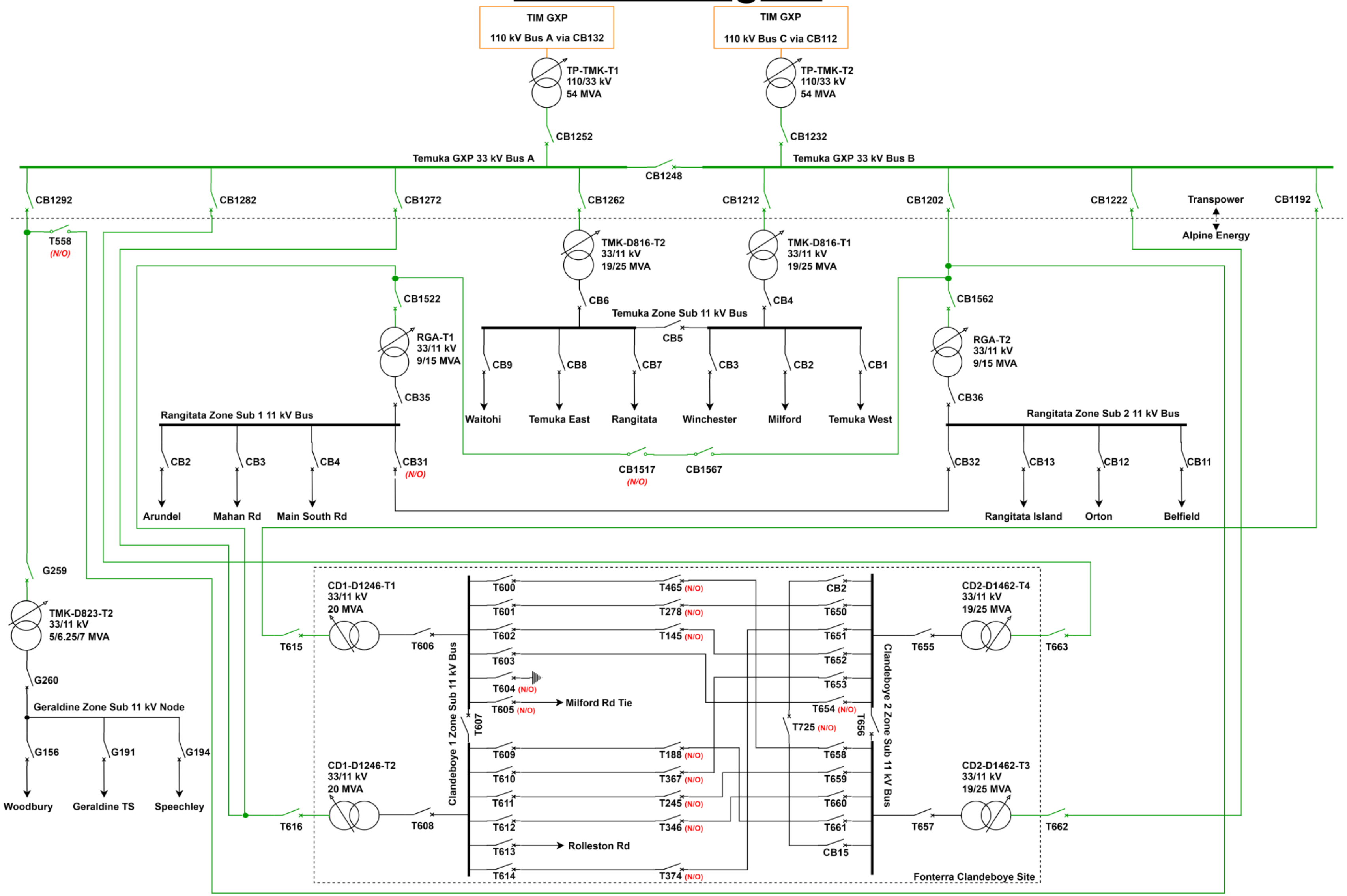
At the GXP, there are two 110/33 kV, 54 MVA power transformers which supply into a double switchboard. These transformers have a Special Protection Scheme (SPS) applied to mitigate against a total supply loss in the unlikely event of a transformer, or 110 kV line trip, while the load is more than 54 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 substation is supplied from a tap off one of the overhead lines.
- 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 two 9/15 MVA transformer with six 11 kV distribution feeders (11 kV bustie is normally closed).
- One subtransmission feeder feeds the 33/11 kV Geraldine zone substation
  - Consists of a single 7 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.

Temuka Region



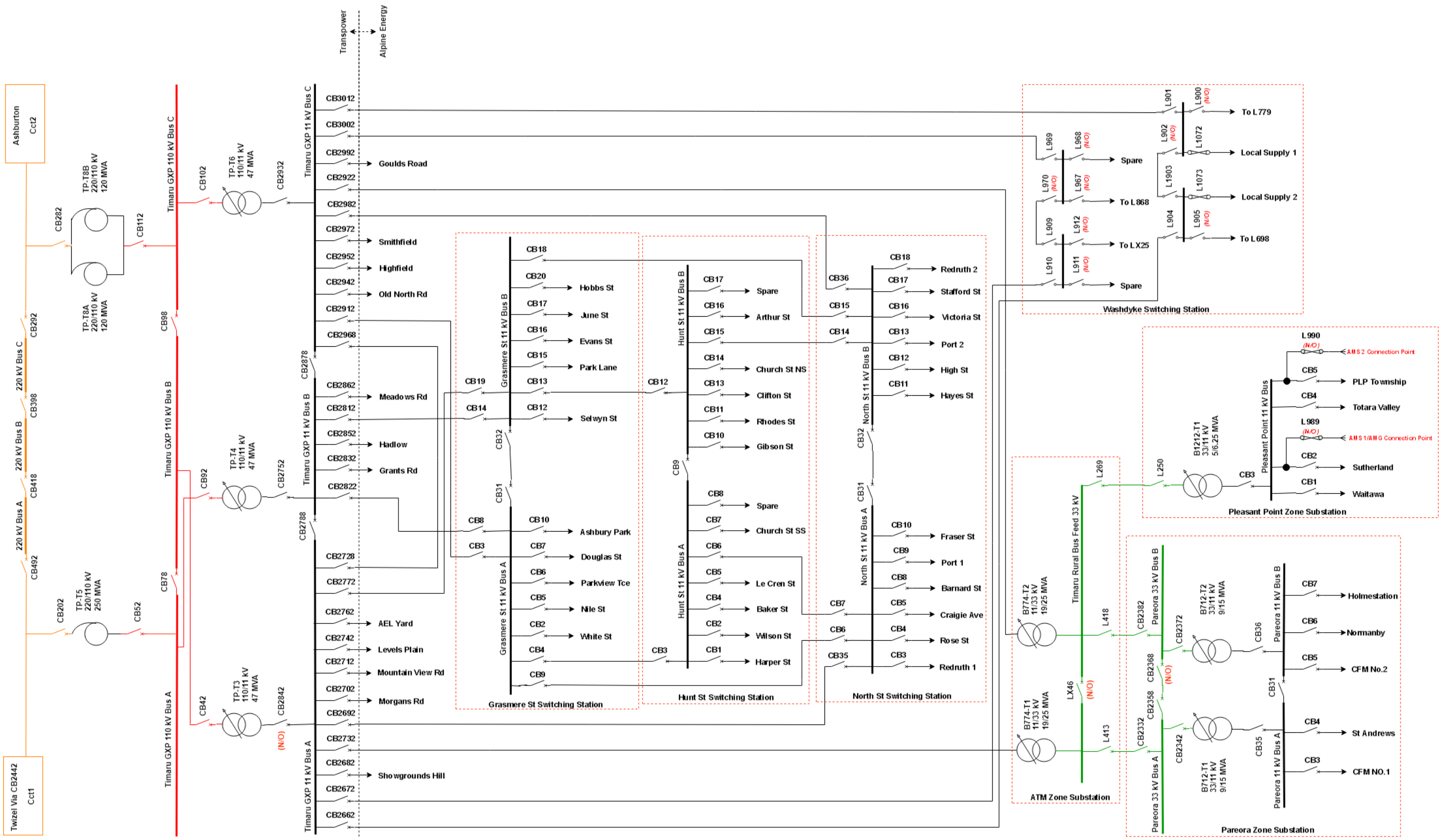
A.6.6 TIMARU REGION NETWORK CONFIGURATION

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.

There are 24 feeders from the 11 kV switchboard which are split across three buses as follows:

- The ripple injection plant is connected to the 11 kV switchboard (bus C).
- 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 33 kV subtransmission feeders to the Pareora zone substation.
  - Pareora zone substation has five 11 kV distribution feeders supplying meat works 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 sub-transmission 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 sub-transmission feeders to Hunt Street switching station and North Street switching station respectively.
- The Hunt Street switching station has ten 11 kV distribution feeders.
  - Two sub-transmission feeders to North Street switching station.
- Two 11 kV sub-transmission feeders connect directly to North Street switching station (cables rated at 33 kV).
  - The North Street switching station has twelve 11 kV distribution feeders. While 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 sub-transmission 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



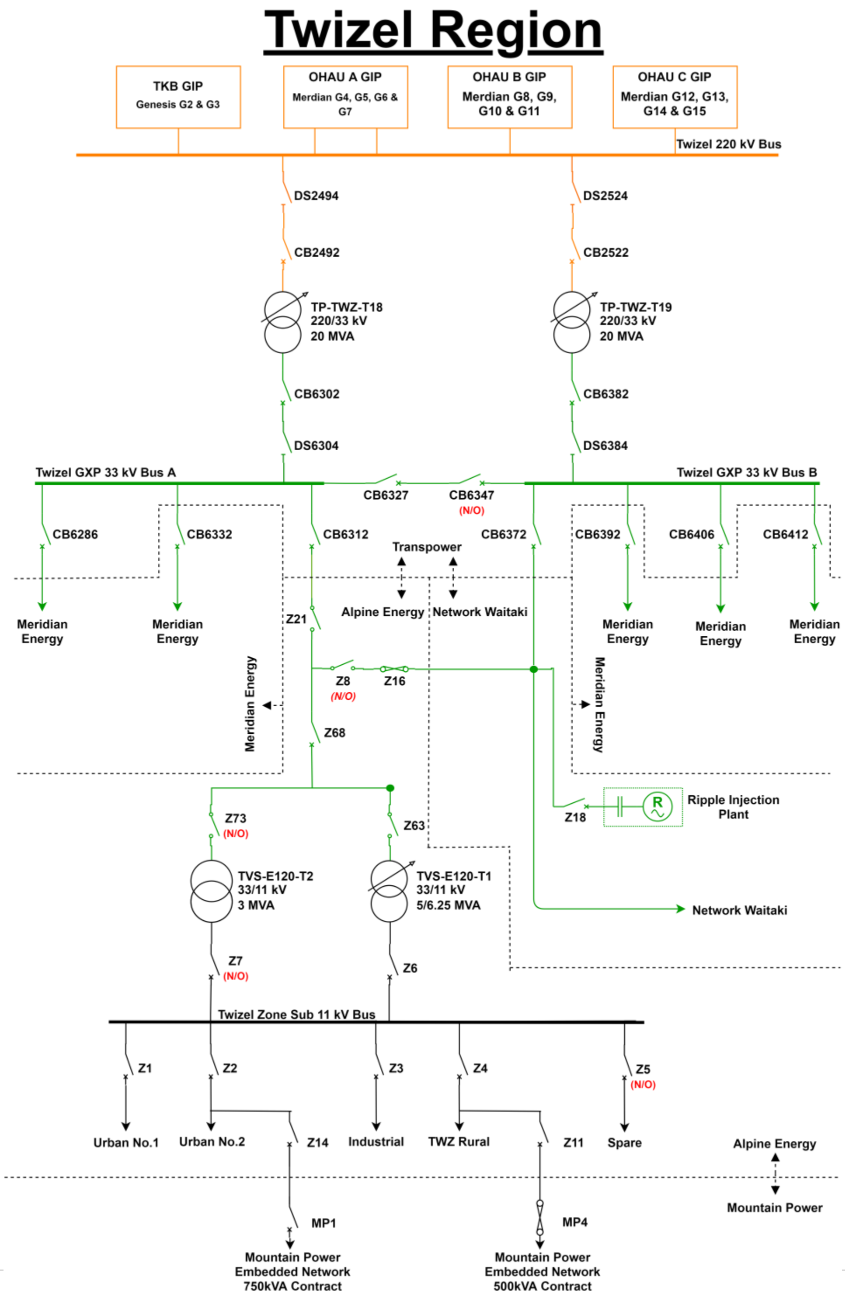
A.6.7 TWIZEL REGION NETWORK CONFIGURATION

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 sub-transmission line supplies our 33/11 kV Twizel township zone substation. At the 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-energised state.

There is an indoor 11 kV switchboard with two distribution feeders supplying the Twizel township, two distribution feeders supplying the surrounding rural areas and one spare circuit breaker. We have an embedded network in the Twizel township supplying new developments in this area. The embedded network is supplied from two connection points at Manuka Terrace and Mackenzie Park.



A.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**;	Section 1.3
	(b) meets the purposes of **AMP** disclosure set out in clause 2.6.2;	
	(c) has been prepared in accordance with Attachment A to this determination;	
	(d) contains the information set out in the schedules described in clause 2.6.6;	Appendix 2
	(e) contains the Report on Asset Management Maturity as described in Schedule 13;	Appendix A2.7
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 6
	(b) the required level of performance is being delivered; and	Section 4.9
	(c) costs are efficient and performance efficiencies are being achieved;	
	(2) Must be capable of being understood by interested **persons** with a reasonable understanding of the management of infrastructure assets;	
	(3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.	Appendix A.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 A	Asset management plans forecast information	AMP Section where addressed
	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;	Section 4.9
	1.2 Monitoring and continuously improving asset management practices;	Sections 7.1 through 7.3 & 7.5 & Appendix 2
	1.3 Close alignment with corporate vision and strategy;	Sections 2.4.2 through 2.4.5
	1.4 That asset management is driven by clearly defined strategies, business objectives and service level targets;	Sections 2.4.2 through 2.4.4 & Chapter 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; Section 6.2 through 6.8, & Appendix 6
	1.7 An emphasis on optimising asset utilisation and performance;	Section 6.2 through 6.8
	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
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;	Discussed throughout the AMP
	2.2 Are clearly documented and made available to all stakeholders;	This AMP is distributed to our main stakeholders, published on our website, and available in hardcopy at our office reception.
	2.3 Contain sufficient information to allow interested persons to make an informed judgment 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;	Appendix 2 – AMMAT self-assessment.
	2.4 Specifically support the achievement of disclosed service level targets;	Section 4.5
	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; Appendix A3
	2.6 Consider the mechanics of delivery including resourcing;	Section 2.2.4; Section 2.5.3
	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 7 through 7.3
	2.10 To the extent practical, use unambiguous and consistent definitions of asset management processes and	We have used terminology in line with this

Attachment A	Asset management plans forecast information	AMP Section where addressed
	terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs; and	Appendix and provided a glossary in Appendix A1.
	2.11 Promote continual improvements to asset management practices.	Section 7.5
	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 & Chapter 5
	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;	Section 5.3
	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 2.4.2 through 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 8
	3.5 The date that it was approved by the directors;	Director Certification section on page 1.
	3.6 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates-	Chapter 4
	3.6.1 how the interests of stakeholders are identified	Chapter 4
	3.6.2 what these interests are;	Chapter 4
	3.6.3 how these interests are accommodated in asset management practices; and	Chapter 4
	3.6.4 how conflicting interests are managed;	

Attachment A	Asset management plans forecast information	AMP Section where addressed
	3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	Section 2.5.1
	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 2.5.2
	3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and	Section 2.2.4; Section 4.2
	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;	
	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-	None
	3.8.3 a description of changes proposed where the information is not based on the EDB's existing business;	None
	3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	Chapter 8
	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;	Section 2.2
	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-	Section 2.4;
	how the asset management strategy is consistent with the EDB's other strategy and policies;	Section 2.4; Chapter 6
	how the asset strategy takes into account the life cycle of the assets;	Section 2.4
	the link between the asset management strategy and the AMP; and	Appendix A3
	processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.	
	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-	Section 2.4.1; Chapter 6
	the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;	Section 7.3 all subsections
	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;	Section 7.3.5
	the systems and controls to ensure the quality and accuracy of asset management information; and	Section 7.3.7

Attachment A	Asset management plans forecast information	AMP Section where addressed
	the extent to which these systems, processes and controls are integrated.	Section 7.3.1
	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;	
	3.13 A description of the processes used within the EDB for-	Section 6.1.3 and 6.1.4 and maintenance sections for all asset types in Chapter 6
	3.13.1 managing routine asset inspections and network maintenance;	Chapter 5
	3.13.2 planning and implementing network development projects; and	Section 4.5
	3.13.3 measuring network performance;	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-	
	(i) identify the documentation that describes the key components of the asset management system and the links between the key components;	Section 2.4.3; Section 2.4.4; Figure 2.1
	(ii) describe the processes developed around documentation, control and review of key components of the asset management system;	Section 2.4
	(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;	None
	(iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and	Section 7.3.1
	(v) audit or review procedures undertaken in respect of the asset management system.	
	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-	
	(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 2.4; Chapter 5; Chapter 6
	(ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.	Section 2.5.3
	3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	Section 1.3 & Chapter 8
	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.	Over the last three years we have restructured our AMP to better reflect the lifecycle stages of our assets. We have also improved readability of the plan so that

Attachment A	Asset management plans forecast information	AMP Section where addressed
		interested parties can understand and follow the process of taking our assets through their lifecycle.
	Assets 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-	
	4.1.1 the region(s) covered;	Section 3.1 and 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;	Chapter 5, Appendix A6
	4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	Chapter 5
	4.2 a description of the network configuration, including-	
	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;	Chapter 5, Appendix A6
	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;	Chapter 5, Appendix A6
	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	Section 6.3; Section 6.4
	4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	Section 6.8
	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.	
	4.3 If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	None
	Network assets by category	
	4.4 The AMP must describe the network assets by providing the following information for each asset category-	
	4.4.1 voltage levels;	Chapter 6

Attachment A	Asset management plans forecast information	AMP Section where addressed
	4.4.2 description and quantity of assets;	Chapter 6
	4.4.3 age profiles; and	Chapter 6
	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 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);	Chapter 6
	4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others;	None
	4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	Section 6.5
	4.5.4 other generation plant owned by the EDB.	None
	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 4.3; Section 4.9
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.	Section 4.9; Appendix A2.6
7	Performance indicators for which targets have been defined in clause 5 should also include-	Section 4.4; Section 4.5
	7.1 Consumer oriented indicators that preferably differentiate between different consumer types; and	Chapter 4
	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 4.9; Appendix A2.6; Mobile sunstation and generators' application for maintenance & emergencies.
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 4.9; Appendix A2.6
9	Targets should be compared to historic values where available to provide context and scale to the reader.	Section 4.9
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.	Forecast expenditure is not expected to materially affect performance under current DPP.

Attachment A	Asset management plans forecast information	AMP Section where addressed
	Network Development Planning	
11	AMPs must provide a detailed description of network development plans, including—	
	11.1 A description of the planning criteria and assumptions for network development;	Section 5.1
	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 5.1 through 5.3
	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-	Section 6.2.5; 6.3.5; 6.4.5; 6.8.5.4; 6.5.9.3
	11.4.1 the categories of assets and designs that are standardised; and	Section 6.5.3.4; 6.6.6
	11.4.2 the approach used to identify standard designs;	Section 6.5.3.4; 6.6.6
	11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	Table 5.1; Sections 5.3.5, 5.6.4, and 6.5.8
	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;	Sections 5.3.1 and 5.3.2; Appendix A3
	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;	Sections 5.9.1 through 5.9.7
	11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	Section 5.2.1
	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;	Sections 5.9.1 through 5.9.7; Appendix°A5
	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	Sections 5.9.1 through 5.9.7
	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
	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;	Section 5.3.2
	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	Section 5.3.3.

Attachment A	Asset management plans forecast information	AMP Section where addressed
	11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	Section 6.7.7
	11.10 A description and identification of the network development program 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;	Sections 5.9.1 through 5.9.7 and Section 6.9 through 6.10
	11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	Section 8.2.1
	11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period;	Sections 5.9.1 through 5.9.7
	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	Sections 5.3.2 and 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	Sections 5.3.2 and 5.4.2
	11.12.2 the potential for non-network solutions to address network problems or constraints.	Section 5.3.3
	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
	12.2 Identification of routine and corrective maintenance and inspection policies and programs and actions to be taken for each asset category, including associated expenditure projections. This must include-	
	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;	Sections 6.1.3; 6.2.6; 6.3.6; 6.4.6; 6.5.3.5; 6.5.4.4; 6.5.5.5; 6.5.7.5; 6.6.7; 6.7.6; 6.8.6
	12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	Sections 6.2.4; 6.3.4; 6.4.4; 6.5.3.3; 6.5.4.3; 6.5.5.3; 6.5.6.3; 6.5.7.3; 6.5.8.3; 6.5.9.2; 6.6.5; 6.7.4; 6.8.4;
	12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	Section 8.2.2.1
	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-	

Attachment A	Asset management plans forecast information	AMP Section where addressed
	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;	Sections 6.2.7; 6.3.7; 6.4.7; 6.5.3.6; 6.5.4.4; 6.5.5.6; 6.5.6.4; 6.5.7.6; 6.5.8.6; 6.5.9.5; 6.6.8; 6.7.7; 6.8.7;
	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;	Section 6.9 & 6.10
	12.3.4 a summary of the projects planned for the following four years (where known); and	Chapter 5
	12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	Chapter 5
	12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	
	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;	Section 7.4
	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	Sections 7.3 and 7.4
	13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	
	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
	14.4 Details of emergency response and contingency plans.	Appendix A.4.3
	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;	Section 4.9.6; Section 8.1
	referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances;	
	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	

Attachment A	Asset management plans forecast information	AMP Section where addressed
	commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.	Section 4.9.6
	15.2 An evaluation and comparison of actual service level performance against targeted performance;	Section 4.9
	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.	
	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.	Section 7.5 and Appendix A2.7
	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	We believe the objectives as described in this AMP are realistic and can be achieved.
	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

www.utilitiesdisputes.co.nz

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