Asset Management Plan 2022

Empowering our Community

ASSET MANAGEMENT PLAN 2022

ALPINE ENERGY LIMITED

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03 687 4300

alpineenergy.co.nz

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1. EXECUTIVE SUMMARY

1.1 GENERAL

The last two years from 2020 and through 2021 have been challenging not just for our company but also for New Zealand at large in dealing with the COVID-19 pandemic. It has come at a significant economic cost from which electricity distribution companies have not been spared. Business continuity was a challenge for staff adapting to work remotely (from home) while efficiencies improved in some areas others found it more challenging due to the nature of their roles.

Our field services were also not spared. Under the different levels of lockdown, they constantly had to adapt and change their work methods to work in 'bubbles' and practice social distancing. Classifying and justifying essential work also required much thought and consideration to keep our staff and contractors safe. The result was that delivering our works program became difficult but, through risk assessments and prioritisation, our network was not exposed to undue risk.

On top of this, the rise in international shipping costs and commodity prices has had and will continue to have an impact on our costs to deliver our capex works program. The lead times for all equipment supplied from overseas have also dramatically increased. Typical lead times of 6-8 weeks, for most equipment, has now increased to 16-19 weeks and for some USA supplied equipment to 50 weeks.

Climate change and the need to decarbonise our economy have significantly changed how we look at operating our electricity distribution industry now and into the future. We have seen our government introduce initiatives to encourage the uptake of electric vehicles (EVs) and the introduction of the government investment in decarbonising industry (GIDI) fund. Both can and have had a significant impact on our network load forecasting and planning for the future. See sections 1.4 and 1.5 for more detail.

To align with our vision of Empowering Our Community through the safe and reliable delivery of electricity to all South Canterbury consumers, and to operate as a successful electricity distribution business (EDB), we have used the key influencers as depicted in Table 1-1 to define our strategic pillars and set our strategic objectives.

Table 1-1: Key strategic influences

Strategic Trend	Trend description
Decarbonisation	The digitalisation of the energy grid is transforming the sector with customers, employees and assets being increasingly connected
Digital Disruption	The digitalisation of the energy grid is transforming the sector with customers, employees and assets being increasingly connected
Decentralisation	Uptake of distributed generation systems in New Zealand are rising quickly
Electrification	Transpower's future energy scenarios project significant process heat and transport electrification by 2050, alongside increased electricity demand
Extreme weather events	Global warming is fueling an increase in extreme weather events
Stable Regulatory Environment	The regulatory frameworks appear likely to continue in a similar form in the near and medium term, with some possible allowance for additional innovation to meet customer expectations and broader energy sector shifts

We have also engaged with our customers, through a consultant, to perform a Voice of Our Customers analysis to better understand the experience our retailers, more prominent customers, and household consumers have with the services we provide to better inform, test, and evaluate our strategic direction. The core needs that were identified are depicted in Figure 1-1.

Figure 1-1: Customer core needs

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 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

This Asset Management Plan (AMP) describes how we approach life cycle asset management of our assets and align with our overall business objectives and strategies. As far as practicable, we aim to align ourselves with ISO 55000 asset management practices that maximise long-term benefits to our consumers. Some key facts and assumptions are made that influence our strategic objectives, as detailed in sections 2.2 and 2.2.4, respectively.

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 direct and align 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 industry best practices.

The various asset type fleet strategies summarise 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 in 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 for regulatory reporting and systems administration.

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

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

1.3 OUR NETWORK

Our network plays an integral role in the economic development of South Canterbury. Despite developments in new technologies with a major emphasis on distributed generation through photovoltaics and battery storage, the bulk of our network can still be considered conventional with the main focus 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 the 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 three core values. Since implementing our Enterprise Asset Management system (EAM), we are now able 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. While irrigation and dairying have tapered off, there are significant sub-division and commercial developments in Tekapo and Twizel.

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 the impact trees that fall outside of the regulations have on our network.

In 2020, we surveyed just over 500 of our consumers across all seven GXPs on perceptions of reliability, outages and notifications thereof, pricing, and electric vehicle (EV) uptake. The survey concluded that mass-market consumers have little if any willingness to pay additional line charges to improve reliability. Consumers do not like interruptions but would prefer sufficient notification prior to planned outages. However, with the recently published 2021 Climate Change Commission Report *Ināia tonu nei,*, it is clear that climate change risks and initiatives will have an impact on EDBs and their networks. We have to adapt quickly to any government initiatives and/or policies resulting from the recommendations in the report. Our distribution network is supplied from seven GXPs. The land use and business activities in each region are very different. Therefore, the CPD (coincident peak demand) is not a good measure for network development, and hence we do our forecasting and network planning by region.

In modelling various scenarios for demand forecast, we:

- systematically fit distribution transformers with smart meters to measure real-time load profiles of the transformer,
- measure voltage profiles on a per-phase basis for 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,
- continue to participate in national forums on this topic, staying current with local and international studies.

1.4 DECARBONISATION

In collaboration with EECA, Transpower and other South Island EDBs we commissioned DETA Consulting to undertake a review of some of our region’s largest energy-consuming sites. This review aimed to identify the larger thermal fuel boiler sites within the Alpine Energy region, collect relevant information, and assist the long-term infrastructure planning needed to deliver a decarbonised future. The criteria set for this study was that the sites:-:

- be located within the Alpine Energy electricity supply area,
- currently utilise non-renewable fuel (Coal, LPG, Diesel, etc.) for heat generation, and
- have a total installed capacity of greater than 500 kW.

The target outcomes of the study were to:

- Better understand the likely decarbonisation technology solutions (with specific focus on fuel switching opportunities) at the sites of interest
- Better understand the current timeframe for decarbonisation (if applicable)
- Undertake a high-level assessment of how these sites might impact electricity distribution and transmission systems
- Undertake a high-level assessment on possible implications on the future energy market
- Assess what incentives or assistance might be needed to increase the pace of decarbonisation

The review found that we have just over 265 MW of fossil fuel loads within South Canterbury, with an estimated consumption of 1,152 GWh per annum. Even with a favourable conversion to electrical load, this is double our current network-wide system maximum demand and approximately double the current electricity usage supplied across our network. To enable and support our consumers in achieving their climate change aspirations and goals, we need to be able to respond quickly to large changes in electricity demand by utilising all technologies and distributed generation available to us.

"Due to the large size of the Fonterra Clandeboye site two option have been selected for the boiler conversation. Option 1 or the BASE OPTION is the switch of the coal boiler to 90% wood chips and 10% heat pump. However due to the large installed capacity there is potential that there may not be sufficient biomass supply to feed the site. Therefore option 2 or the ALTERNATIVE OPTION describes the switch of the boilers at Clandeboye to 90% electrode boilers and 10% heat pumps. As both options represent a large increase in the associated fuel type, they will have a drastic effect on the supply and availability of the respective fuel."[1]

Some key findings of this report are:

- The dairy factories in our region dominate the current thermal heat demand.
- An additional 23 MW of electricity capacity will be required to supply the target sites in the next 15 years if the dairy factories opt for biomass as depicted in Figure 1-2 (Base option).
- Biomass has a strong role to play for some sites, this is largely dependent on the dairy sites and whether they move to electrify or use biomass. Currently if they move to biomass the total increase in biomass in the next 15 years will be 154 MW.
- An additional 98 MW of electricity capacity will be required to supply the target sites in the next 15 years if the dairy factories opt for electrode boilers as depicted in Figure 1-3. (Alternative option)
- Fonterra Clandeboye represents a potential 75 MW increase in electrical capacity if they switch to electric (combination of electrode boilers and heat pumps).

Figure 1-2: Base case transition - Electricity supply increase of 23 MW

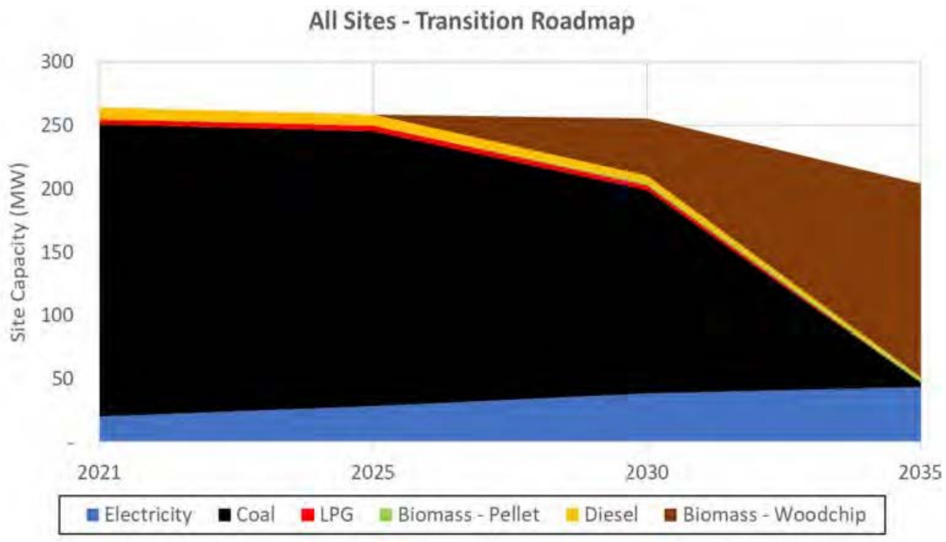
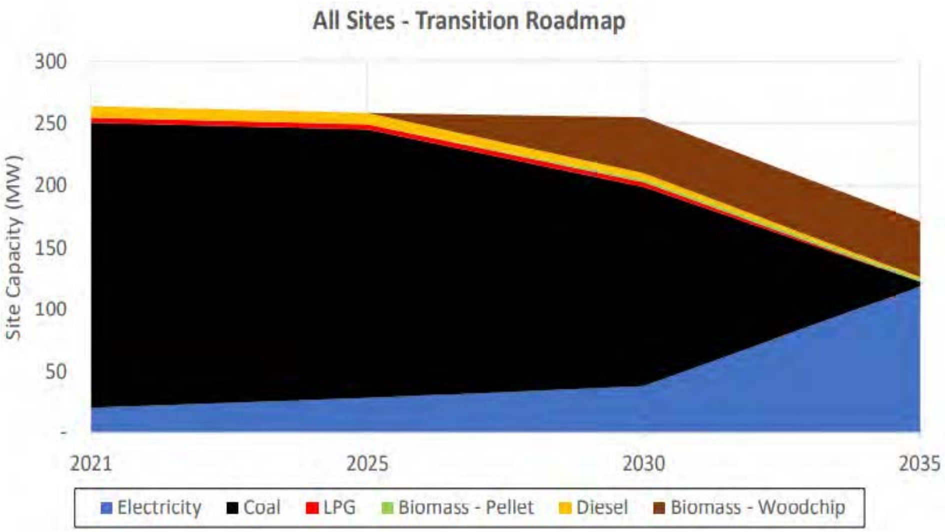


Figure 1-3: Alternative case transition - Electricity supply increase of 98 MW



[1] *Alpine Energy - Thermal Fuel Transition Impact Assessment*, DETA Consulating, 20 September 2021.

For the base case scenario, the additional 23 MW supply requirement is achievable with small to moderate investment in our network. At the moderate end, we will have to use the Commerce Commission's reopener mechanism to obtain the additional capex allowance to enable the decarbonisation effort. This load level constitutes 16% of our current overall network-wide maximum demand.

For the alternative case scenario, the additional 98 MW supply requirement constitutes 70% of our current overall network wide maximum demand. It is also more load than what our current Timaru or Temuka GXPs can supply. Not only would this require significant investment at our distribution network level but also at a Transpower GXP level. Investments of this nature requires extensive analysis and regulatory evaluation, and typically takes in the order of three to six years to be approved, designed, and constructed. The potential impact of these loads at an GXP and zone substation level is discussed further in section 5.8.1.

Our expectation is that the most realistic scenario lies between these two cases with only portions of current processing converting to biomass, due to supply constraints, while others will either remain as is or convert to electricity. Irrespective, anything above 23 MW of additional load, depending on the location(s) will require moderate and possible significant investment.

There were two successful South Canterbury applicants for the first round of the GIDI fund allocations Wool Works and McCain Foods. While McCain Foods have decided to opt for biomass to replace their coal fired heat processes, Wool Works approached us with a request for electrical supply to a new electrode boiler of circa 9 MW. The magnitude of this load is such that it has now initiated a discussion with Transpower regarding the upgrade of the Timaru GXP.

Another aspect of decarbonisation of the South Canterbury and New Zealand economy regards the large number of substantial distributed generation (DG) applications we have received over the last year. In total, seven applications for large scale DG represents a potential 130 MW of generation that could be connecting to our network.[2] This must be considered against the reality that the peak demand for electricity across all of our network is around 140 MW. The implications are that in most instances we will have to deal not only with reverse power flows but also grid injection requirements and constraints as required by the System Operator (i.e. Transpower). Suffice to say, due to timeframes involved and the uncertainty until a form of connection contract is signed, connecting these DG systems will have a significant impact on our forecasting and capital expenditure related to our regulatory allowances in DPP3.

1.5 ELECTRIC VEHICLES

Under the government policies in force at 2020, our customer survey indicated that we should not allow for any substantial uptake in EVs and associated infrastructure capacity for the next four to five years. The rapid growth internationally in the uptake of electric vehicles (EVs) is causing 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.

[2] Some of these applications have progressed through to the final application stage where detailed network and grid studies are conducted to determine the feasibility and technical requirements.

Transpower's *Whakamana i Te Mauri Hiko – A Roadmap for Electrification* report states that "on the transport side, without significant policy change, consumers are not likely to adopt EVs at the scale and speed required to meet our 2030 emissions target".

Aotearoa's policy direction for EV's has recently been developed, and in early stages indicates a strong uptake in EV registrations nationally. This is also reflected in South Canterbury with 50% of 2021 registrations occurring in the last quarter of the year. We expect this trend to continue into 2022 because of higher fuel prices.

The implications for distribution companies should not be underestimated and our forecast capital expenditure to ready our network for this load increase as well as the decarbonisation of process heat in South Canterbury, depicts an increasing trend from 2023 through the remainder of DPP3 as shown in Figure 1-9.

Our 2020 consumer survey indicated that the uptake of EVs in South Canterbury was not a high priority for households at the time. This may have changed due to the government's "Clean Car Feebate Scheme" based on a new car's vehicle's $C0_2$ emissions resulting in 50% of 2021 EV registrations occurring in the last quarter of the year. This feebate scheme has increased EV registrations in South Canterbury after a declining trend from 2018 through to 2020, registering a new high of 50 new registrations in 2021. The place of residence for most of the registrations continues to be in Timaru and Geraldine in the second place. There seems to be a correlation between population density and average affluence in relation to EV uptake. However, due to the relatively low numbers still, load forecasting for EV charging specifically is still subsumed within our normal load forecasting regime.

In 2019 we had over one million tourists through South Canterbury mainly along the main tourist route through Geraldine, Fairlie, Tekapo, Mt Cook and Twizel. Many international tourists are climate-conscious and will prefer travelling through New Zealand, leaving as small as possible carbon footprint. We expect a significant increase in electric transportation along this tourist route. Consequently, we will ensure that sufficient electric charging facilities are available through investment in infrastructure and continued partnering with local authorities and businesses. Our capex forecast for DPP4 includes provisions for these upgrades.

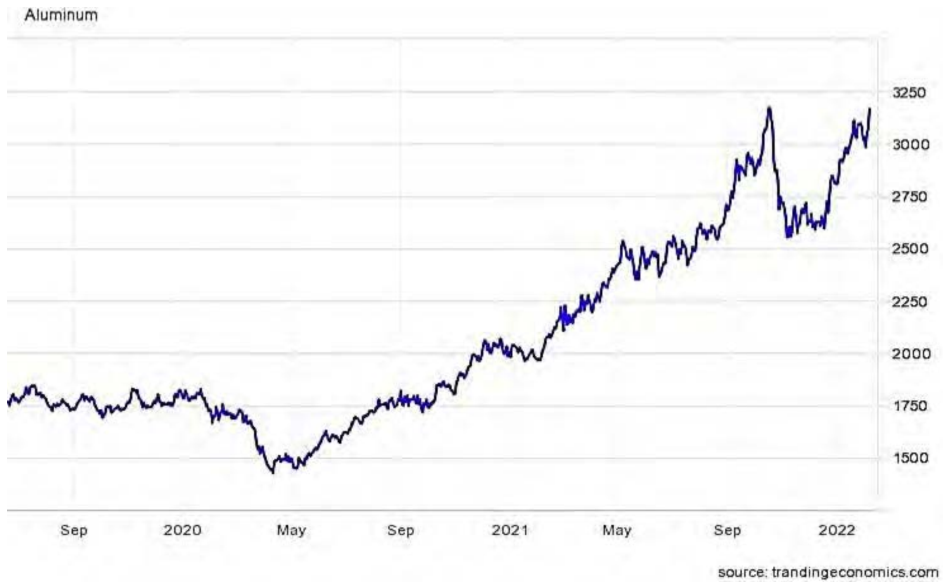
With new and used EV's in the passenger vehicle market, and "Vehicle-to-grid" technological advances it is foreseeable that we could see EV batteries being used for small scale local energy storage in the future. In this manner EVs would make combined PV and battery installations much more affordable 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 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 must be aware of 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 4.10.2.

1.6 COMMODITY PRICES

As stated in section 1.1, commodity prices have risen steeply as a result of the worldwide COVID-19 pandemic. Large scale reduction in international manufacturing and shipping has seen transportation costs rise in unison with commodity prices. We have not been unaffected by this in our industry. The price of materials used in everyday EDB infrastructure construction such as aluminium, steel, copper, and tin has risen significantly. Figure 1-4 through Figure 1-7 depict the rise in prices for these metals over the last two and a half years.[3]

Figure 1-4: Aluminium prices (US$ per tonne)



Aluminium, copper, and steel are primary raw product inputs in the manufacturing of underground electrical cable and overhead line conductor, while most of our substation equipment have a large steel component.

Nationally the producer price index has also risen markedly, as depicted in Figure 1-8 where the quarterly changes are depicted with the blue bar graph and the black line representing the index.[4]

[3] Source: https://tradingeconomics.com/commodity/ (Al and Tin in USD/T, Fe in CNY/T & Cu in USD/Lbs)

[4] Source: https://www.economy.com/new-zealand/producer-price-index-ppi/not-seasonally-adjusted

Figure 1-5: Steel prices (Chinese Yuan per tonne)

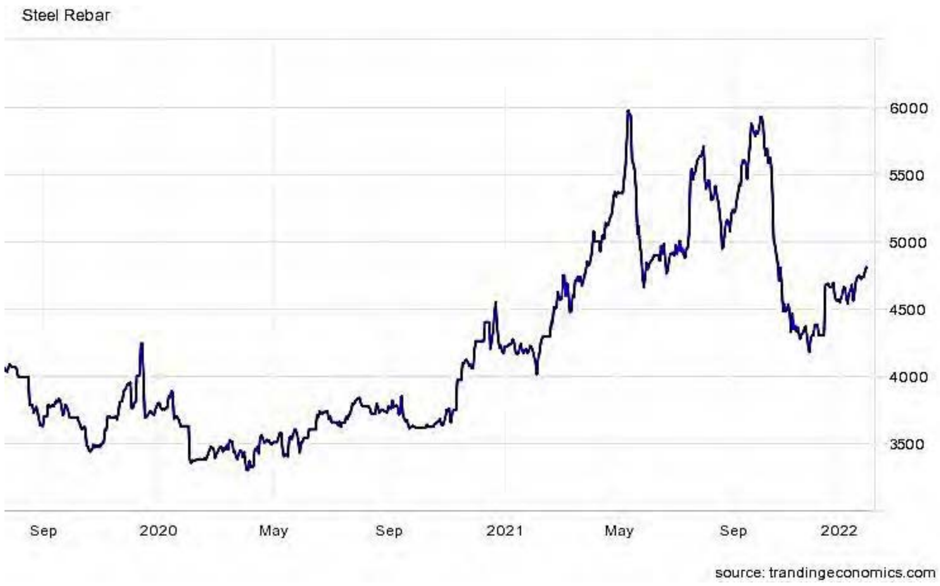


Figure 1-6: Copper prices (US$ per pound)

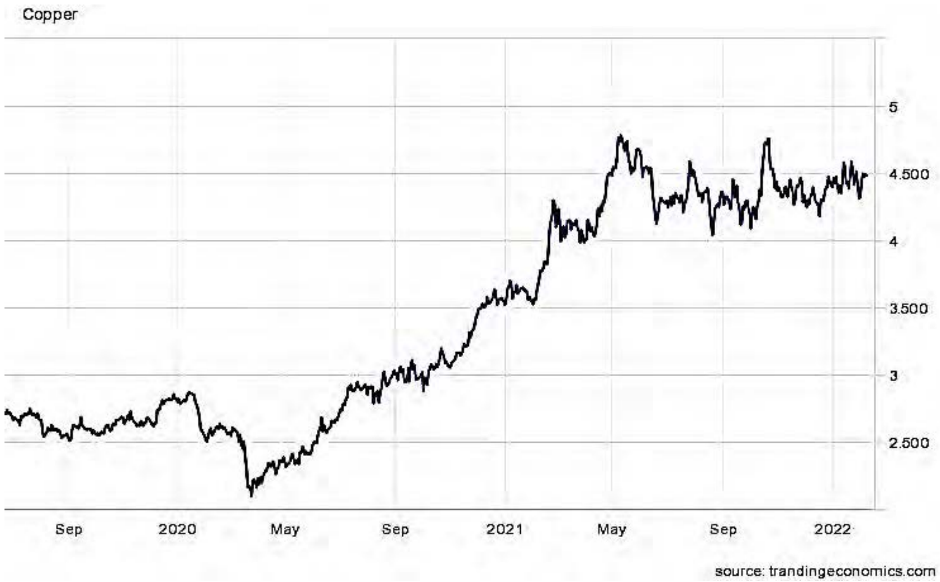
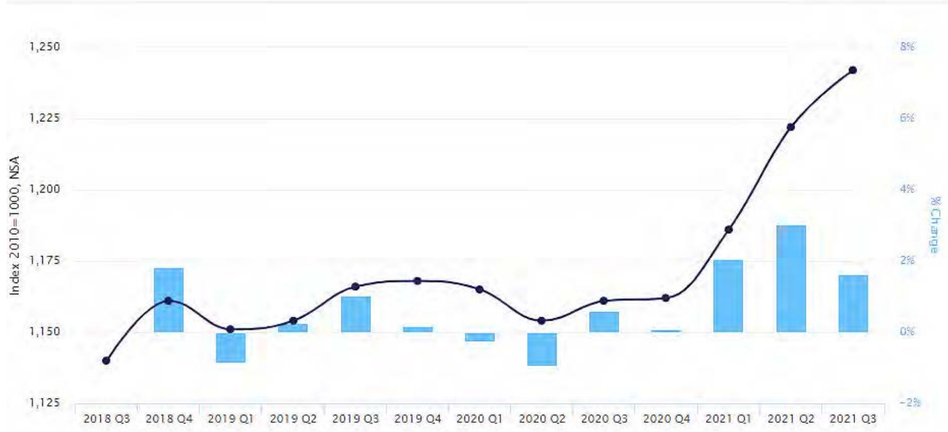


Figure 1-7: Tin prices (US$ per tonne)

Figure 1-8: Producer price index



1.7 OUR INVESTMENT IN OUR NETWORK TO 2032

This AMP outlines our approach to asset management, and the forecast CAPEX and OPEX for the planning period of 2022 through to 2032 are depicted in Figure 1-9 and Figure 1-10. Expenditure is given in NZ dollars constant values as of 2021. 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). We have also adjusted our forecast based on increased shipping cost for equipment sourced overseas, higher commodity prices, and the higher wage inflation numbers.

Details of the makeup of our CAPEX and OPEX are given in Section 8.

Figure 1-9: Total CAPEX for the planning period

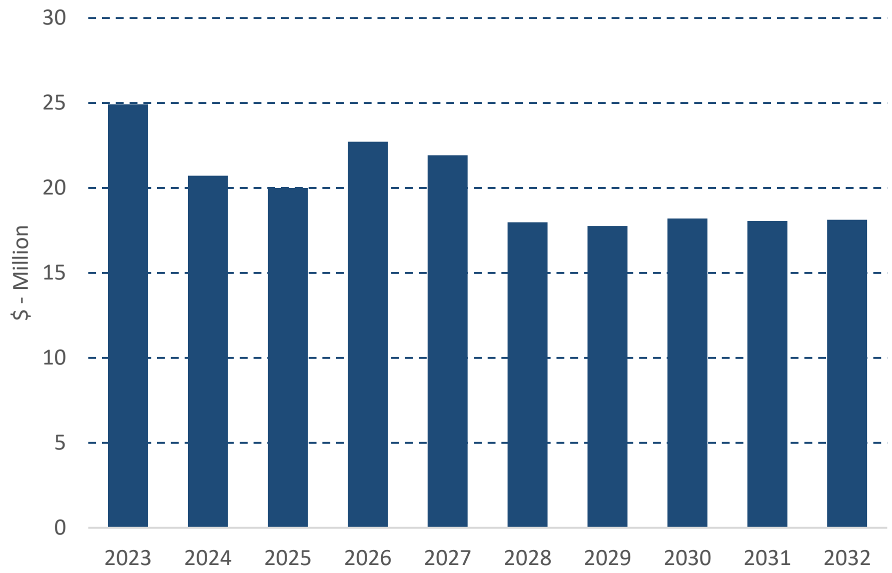
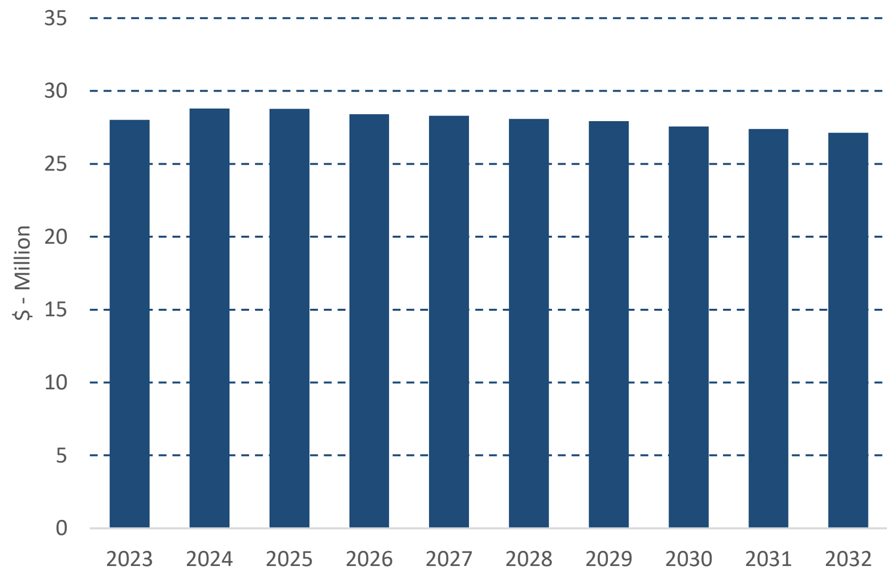


Figure 1-10: Total OPEX for the planning period



1.8 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, when and where 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 prospect that could allow peer to peer trading facilitated through our network. We have received multiple applications for the connection of multi-megawatt distributed generation installations on our network.

In 2021 we surpassed 2.5 MW in PV solar installations on our network, with 2018 a record year with 83 installations comprising 446 kW of installed PV solar. However, since 2018 there has been a decline in the number of annual installations, although the annual installed capacity remained constant. We have however received a number of applications for large scale generation wanting to connect to our network. In total, seven applications spread across five of our GXPs, comprise 128 MW of generating capacity. More details are given in section 5.8.2.

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 load and voltage information obtained from advanced meters also allow us to proactively recognise and identify possible safety concerns at consumers' installations.

In the area of drone technology, the use of drones on our network allows us to assess the condition of network assets in a safer manner and dramatically reduces the time needed to complete inspections assisting us to deliver a safe and reliable network more efficiently. One application area we are currently using drones for is the inspection of overhead lines during unplanned outages. It was practical against the background of the mycoplasma bovis outbreak in South Canterbury, where access to private land has become a biosecurity issue creating time-consuming and costly impacts on our network reliability statistics. We are currently working with a third party to commence trialling the use of Artificial Intelligence (AI) for overhead line inspections and condition assessment of the pole tops and associated equipment. By bringing together new technology with essential infrastructure services, we are accelerating the transition to a modern grid. Figure 1-11 shows the drones in action.

Figure 1-11: Using drones to inspect pole top condition

2 / Introduction

2. INTRODUCTION

This chapter outlines the purpose of our AMP and the strategic pillars upon which we have built our strategic objectives. In turn our strategic objectives sets the framework for the asset management strategy. We also detail some key assumptions integral to our AMP investments, load forecasting, adoption of new technologies, and service delivery strategy. Our asset management framework (AMF), including objectives and responsibilities for asset management at all levels in our organisation is .

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 flows out of and is the result of our AMF which accounts for the alignment of our asset management objectives with our company goals across the complete asset lifecycle of all asset fleets, measured against the AMMAT (Asset Management Maturity Assessment Tool). Our asset management objectives as detailed in section 2.5.3.

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 9 December 2021, published 9 December 2021.

2.2 OUR STRATEGIC PILLARS

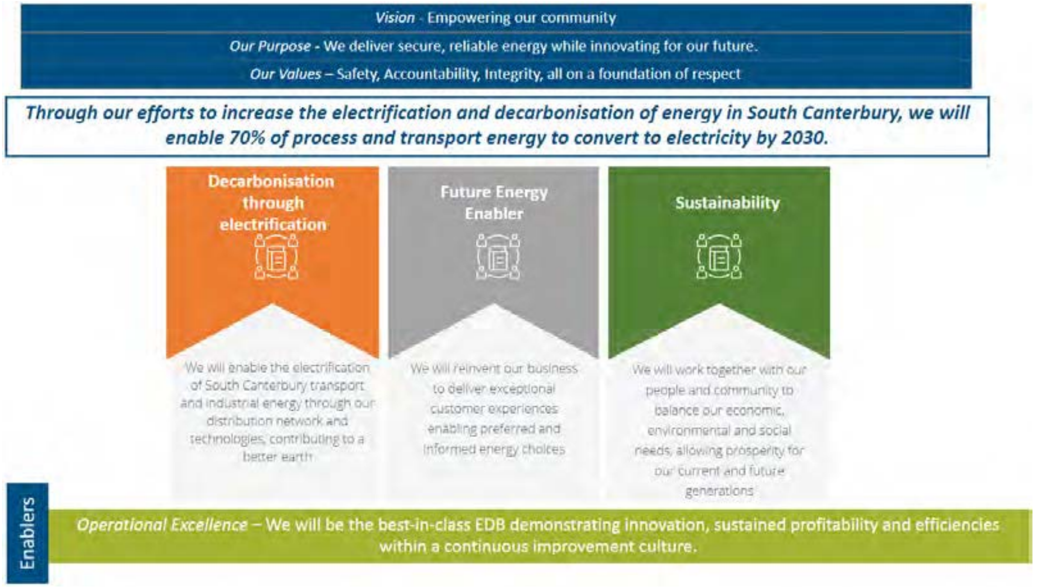
Our three strategic pillars form a critical part of our aspiration. The strategy development process built upon this aspiration to enable us to make choices to support these pillars. We work together to deepen our strategy and examine what it would take to implement the strategy and measure success.

The three strategic pillars form the foundation upon which we strive for our **vision**, define and give effect to our **purpose** within the framework of our **values**. We recognise that this is only possible when enabled through operational excellence as depicted in Figure 2-1.

2.2.1 OUR VISION

Our vision of *Empowering Our Community* is one that is shared across all levels of our business. This does not just speak to the electricity that we transport to our consumers but extend well beyond that to the local community support through scholarships and grants, making our facilities available for community use and more.

Figure 2-1: Our Strategic Pillars



2.2.2 OUR PURPOSE

Our purpose is derived from the fact that we are an asset management company and therefore strive to *deliver secure, reliable energy while innovating for our future*.

Built upon our strategic pillars, we will succeed in our purpose when we deliver electricity through the establishment, operation and maintenance of a sustainable network that is accessible to users for the supply of decarbonised loads as well as connecting distributed generation.

2.2.3 STRATEGIC OBJECTIVES

Our strategic objectives are depicted in Figure 2-2. In achieving our strategic objectives, we must eliminate waste and strive for the highest levels of efficiency. Therefore, we will have data and technology at the heart of our business. In this fast-changing environment, we want to help our consumers have exceptional experiences in dealing with us to enable them to fulfil their objectives and goals with respect to better, sustainable, and long-term energy requirements.

In considering the risks and challenges of climate change, we have a strategic objective to enable all decarbonisation and electrification needs of our consumers in so far as technology and our authority allows.

Figure 2-2: Our Strategic Objectives

2.2.4 OUR STRATEGY

Our key focus for the future is to invest substantially in our core business with a singular focus on optimised cost and reliable electricity distribution delivered through our distribution network. This is whilst balancing flexibility services and additional decarbonisation electricity load. We have termed this "Modernising our Foundations."

This will require a degree of business transformation such as process improvements, technology platforms, data analytics, information visuals, and change management. It will also require a clear and nuanced understanding of our customer needs, pain points, and expectations, closely informing us of our future investment decisions.

Our people will remain at the heart of what we do and pivotal to achieving this strategy. We will continue to invest in their learning and development and implement strategies to attract and retain talent. As we embark on this journey, we recognise the extent of the changes required to position us to answer the needs of our region and New Zealand's low carbon future.

2.3 KEY FACTS AND ASSUMPTIONS

2.3.1 LOAD FORECAST

New connections and the upgrades of existing connections grew our load continuously throughout 2021, while some large-scale customer connection projects are scheduled for 2022. The South Canterbury area is very buoyant with development within the residential, commercial, and rural sectors. Timaru's Port has seen large growth and development, providing a combination of additional connections and network CAPEX work. Changes to water consents, for irrigating witin the Waimate farming region, caused many overhead power line relocations and required new connections to supply power to new pivot irrigators and pump connections. The move to electricity away from coal, for heating and process heat, has continued with the installation of commercial heat pumps in schools and businesses. The government's GIDI fund are sponsoring a small number of local businesses to reduce their carbon emissions, whilst most are considering moving to biomass for process heat.

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 5.9 for the various regions we supply.

The load demands detailed in this AMP do not include any 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.

Based on current supply levels, the increasing but still relatively low load levels for EVs in South Canterbury, we have not allowed for a specific or material load forecast increase for EV charging in DPP3. We are continually monitoring this load as the economics of EVs and fossil fuel cost changes and we anticipate that budgets for DPP4 will have to take expenditure to supply this load into account.

2.3.2 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, the public, and electricity users.

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.

It is also worth noting that initiatives in decarbonisation will and have put pressure on capital budgets and also on current DDP3 capital investment allowances. This will continue if the scale of these projects does not meet the regulatory threshold for re-openers[5]. Where possible we will make use of the re-opener mechanism to obtain regulatory approval for projects that contribute towards decarbonisation.

2.3.3 NEW TECHNOLOGIES

We view distributed generation as an enabling technology for network support rather than network replacement. We assume new technologies may reduce demand load on our network but will not have the ability to substitute for network development. However, we do recognise the importance and the potential impact of distributed generation on our business. The government's vision of an affordable, secure, and sustainable energy system that will cater to New Zealanders' wellbeing in a low emissions world will stimulate distributed generation through our network. The government plans to increase investments in low-emission technologies will influence our consumers' choices of process heat energy sources and may potentially increase the electrical energy load of our customers.

The availability of solar pumps as well as stand-alone generation consisting of PV, batteries, and diesel generation in an integrated unit, could be viable options for rural power requirements. To benefit from their resources and capabilities, we are aligning ourselves with others in the industry doing research, trials, and experimentation with new technologies at a network level.

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. Section 4.10 details the current levels of mainly domestic scale PV on our network, while section 5.8.2 details large scale DG applications. The number of installations, as well as the cumulative capacity of PV installations, reflect a linear growth rate. While the small-scale solar connections on our network have not increased significantly, the opportunity for large-scale HV interconnected solar sites seems likely within the planning period of this AMP. In developing and evaluating options for solutions to network capacity, reliability, or security constraints, we consider new technologies. This strategy will, in future, have a significant impact on our network, but won't impact the management of our assets in the 2022/2023 period.

2.3.4 SERVICE DELIVERY ARRANGEMENTS

We will continue to use NETcon Limited as our main contractor for the construction and maintenance services to most of our network through a master services agreement for the 2022/23 period. These services are based on independent industry verified rate cards to ensure efficient expenditure. Where rate cards are not possible for complex and varied work scopes, we will go to the market to obtain the most cost-effective solution. For new connection projects, our consumers can obtain the services of any network approved contractor.

We depend on the capability of our staff and contractors to operate and maintain our assets. Only workers who are registered on our "competency matrix" are deemed competent to work unsupervised on our network. The competency matrix requires workers to be trained to specified unit standards by accredited training providers. Workers need to present the associated qualifications, such as their EWRB practising licences, prior to having their competencies assessed. Each competency is then assessed using "Exposure" assessment forms, which are completed and signed off under the direct supervision of a competent worker. These competencies are recorded on our competency matrix once it's been accepted. These competencies are reassessed every 24 months.

2.3.5 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.

2.3.6 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 DPP3 Determination, our maximum allowable revenue is capped, and our lines charges will be managed annually to comply with this cap. We are mindful of the impact price increases have on households and businesses and our obligation to balance cost increases against the need to provide a resilient network for our growing communities.

2.4 NETWORK AND ASSET OVERVIEW

We supply electricity to over 33,700[6] 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 $210 million.

Electricity is delivered to our network via seven grid exit points (GXPs) with Transpower and one noticeable embedded generator of 7 MVA at the Opuha dam. The network delivered over 836 GWh of energy and had a half hour average coincident maximum demand of 144 MW[7] in 2020/21 regulatory period. Energy consumption was down from the previous high of 841 GWh and the half hour average coincident maximum demand is slightly up from 140 MW in 2019/20.

Our network is made up of the asset fleets and populations depicted in Table 2-1. The network is in an overall good condition, and asset fleet details are discussed in Section 6.

[5] A mechanism whereby an EDB can apply to the Commerce Commission for additional capex for large unforeseen projects or programmes that are not included in the EDB's capex forecast for the regulatory period. There are thresholds that must be met for this type of application.

[6] As at 31 March 2021

[7] Recorded on 29 January 2020 (15:30).

Table 2-1 Asset fleet and populations as at 1 October 2021

We have 852 km of distribution and LV cables and .. 	3,510 km of distribution and LV overhead lines, and .. 	44,500 wood and concrete poles, 	
26 zone substations, with .. 	27 power transformers, 	172 indoor circuit breakers across our network, .. 	connecting 441 ring main units, .. 
1,067 ground mounted transformers, .. 	69 reclosers and sectionalisers, .. 	68 voltage regulators, .. 	4,997 pole mounted transformers, .. 
11 capacitor banks, .. 	link boxes and .. 	distribution boxes to supplying .. 	33,700 ICPs, our consumers. 

2.5 ASSET MANAGEMENT FRAMEWORK

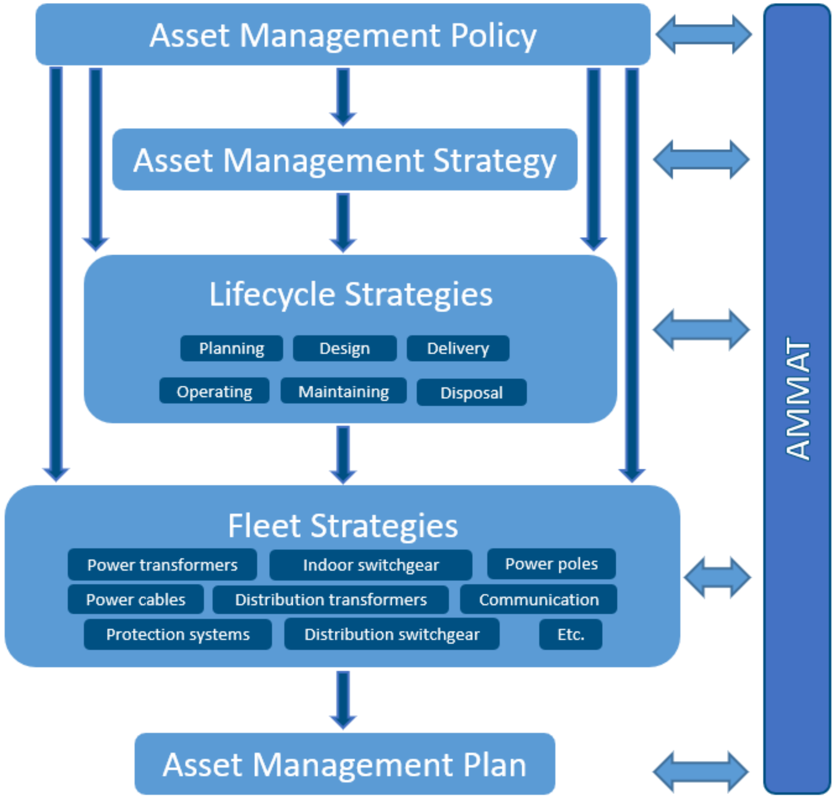
2.5.1 OVERVIEW

Our asset management framework (AMF) details the various levels at which asset management activities are performed to give a clear line-of-sight in how all activities contribute to achieving the overall company objectives. 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 2-3 and represents a suite of documents that describe how we manage our assets throughout their lifecycle. This suite of documents has been developed, and at the time of this publication, we have completed most documents except for some low-value 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 AMMAT as detailed in Appendix A.2.1. Planned improvements are detailed in section 7.5.

Figure 2-3 Asset Management Framework



2.5.2 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:

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

Asset Management Policy

We are committed to ensuring that our distribution network is planned, designed, constructed, operated and maintained 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 including environmental responsibility and sustainability, while supporting New Zealand's **climate change** objectives through the **de-carbonisation** of the economy
- evaluating the **costs and risks** in delivering expected performance and maximising asset value
- ensuring that asset management decisions for investment, maintenance, operational expenditure, and replacement are made on all 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 to deliver our asset management objectives
- engaging with our **community and stakeholders** to improve relationships through all asset-related activities that affect them
- continually develop our asset management **systems** to effectively turn data into information that will optimise our asset value.

2.5.3 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 by providing 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.
- In considering all five of the above objectives, we will do so within the context of **reducing our carbon footprint**, enable any and all **distributed generation** initiatives that requires a connection to our network, and support consumers and stakeholders in their **decarbonisation** initiatives.

2.6 RESPONSIBILITIES FOR ASSET MANAGEMENT

The responsibilities for asset management are set out in Figure 2-4.

2.6.1 OUR BOARD

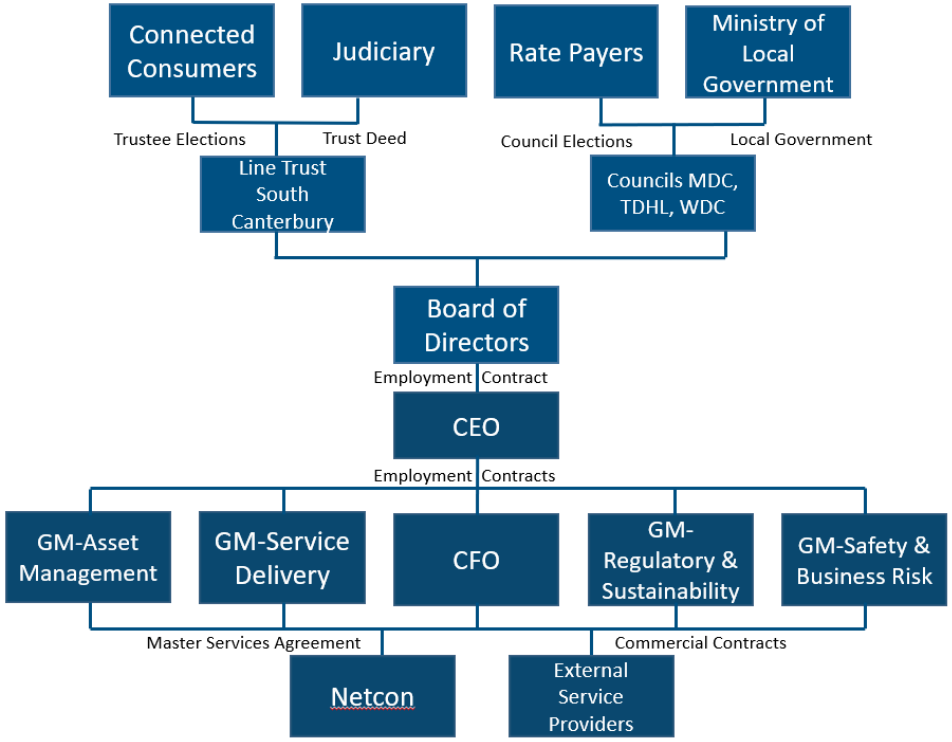
The board of directors governs our business. The board has delegated overall responsibility for the management of our assets to the CEO. Our directors are accountable to our shareholders, TDHL (Timaru District Holdings Limited (through Timaru District Council - TDC)), WDC (Waimate District Council), MDC (Mackenzie District Council), and South Canterbury Line Trust, through our SCI (Statement of Corporate Intent). We presently have six directors who are appointed as follows:

- two directors appointed by the Line Trust South Canterbury
- three 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:

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

Figure 2-4: Accountability and mechanisms for asset management



Full board meetings are held at least every two months, with a number of additional special-purpose board meetings, e.g. for review and approval of regulatory documents. 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 board of directors approve projects 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.

2.6.2 OUR EXECUTIVE MANAGEMENT TEAM

Our Chief Executive Officer (CEO) 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. The CEO leads a team of five executive managers, depicted in Figure 2-5, to achieve the company objectives and execute the strategy as set by the board of directors.

Figure 2-5: Executive Management Team

2.6.2.1 CHIEF FINANCIAL OFFICER

The Chief Financial Officer (CFO) leads the Financial, People & Culture, Communications & Marketing and Digital Services teams. These teams are responsible for ensuring that the appropriate systems, policies and procedures are in place to support and enable the effective delivery of the asset management plan. The team further supports the implementation and monitoring of governance and management practices at all levels throughout the business.

2.6.2.2 GENERAL MANAGER – ASSET MANAGEMENT

The GM Asset Management leads the planning, engineering design, project engineering, asset information, and asset lifecycle teams. These teams are collectively responsible for setting the strategic direction for the network asset fleets. This is achieved through system planning and load forecasting, asset renewal and replacement strategies, maintenance of all asset fleets, and by ensuring accurate and up to date asset information.

2.6.2.3 GENERAL MANAGER – SERVICE DELIVERY

The GM Service Delivery leads the delivery and execution of the Asset Management Plan. The service delivery team consists of network operations, customer services, vegetation management, procurement, and works delivery. This team is responsible for the efficient operation and maintenance of our network as well as the delivery of our AMP works program.

2.6.2.4 GENERAL MANAGER - SAFETY & BUSINESS RISK

The GM Safety & Business Risk leads our effective achievement in the management of the company's safety and business risk functions by building a deeper understanding of risks that will prioritise prevention mitigations designed to keep Alpine Energy and the community safe. The unit champions the efficient and effective development, implementation, oversight, reporting and continuous improvement of safety and business risk frameworks, policies, procedures and reporting in accordance with company and legislative requirements.

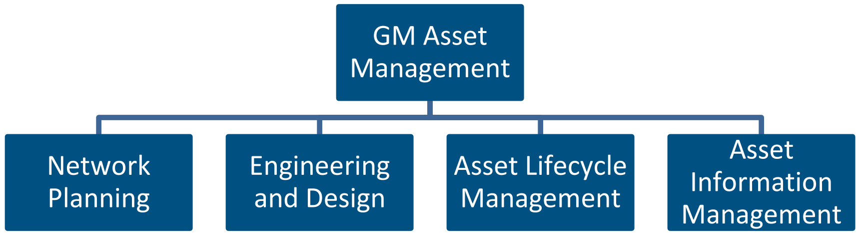
2.6.2.5 GENERAL MANAGER – REGULATORY & SUSTAINABILITY

The GM Regulatory and Sustainability is responsible for ensuring that we meet our annual regulatory obligations, as set primarily by the Commerce Commission and Electricity Authority, and leads responses to invites from regulators for submissions, consultations, and other feedback. The team is responsible for annual price-setting, monthly billing, and other commercial support. The GM Regulatory and Sustainability also leads the development and implementation of our sustainability strategy to ensure that sustainability features in everything we do.

2.6.3 ASSET MANAGEMENT

The asset management team structure is depicted in Figure 2-6. The asset managers drive the budget detail and review of the AMP.

Figure 2-6: Accountabilities for strategic asset management



2.6.3.1 NETWORK PLANNING

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

2.6.3.2 ENGINEERING AND DESIGN

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

2.6.3.3 ASSET LIFECYCLE MANAGEMENT

The Asset Lifecycle Management team are responsible for the management of assets over their life. This includes the compilation and implementation of maintenance schedules and the maintenance specifications of existing electrical assets on our network. The team's responsibility extends to the collection and management of asset condition data as well as compiling a program for asset replacements.

2.6.3.4 ASSET INFORMATION

The asset information team comprises our GIS and drafting teams. They are responsible for updating network information in our GIS and drawing management systems for all new assets and any modifications made to existing assets. The team is also the custodians of all asset data and information systems such as GIS, EAM and drawing management.

2.6.4 SERVICE DELIVERY

The service delivery team structure is depicted in Figure 2-7.

Figure 2-7: Accountabilities for asset management in service delivery

2.6.4.1 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 that high levels of consumer services are maintained. The team is also responsible for:

- all network switching,
- managing load control,
- ensuring that work on the network is done safely and with as few, and shortest supply interruptions as possible,
- vegetation management and,
- maintaining our system automation (SCADA – Supervisory Control & Data Acquisition).

2.6.4.2 CUSTOMER SERVICES

The Consumer Service team is responsible for processing all new connection and distributed generation applications to our network. The new connection application process includes low-level designs, connection agreement processing, commercial arrangements, and the managing of contractors appointed to construct and connect new connections. The team is also responsible for the technical and administrative metering functions, retailer service requests such as disconnects, reconnects and site visits.

2.6.4.3 NETWORK PROGRAMME & WORKS DELIVERY

The network programme and works delivery team is responsible for effective and efficient delivery of the network works programme and projects, scheduled maintenance plan, and vegetation programme. The team also manages procurement via external contractors / suppliers and manages contractor performance.

3 / Network Overview

3. NETWORK OVERVIEW

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

3.1 OUR NETWORK AREA

Our network stretches over 10,000 km², bounded between the Rangitata River in the north and the Waitaki River in the south. To the west, our supply extends to the Southern Alps as far as Mt Cook Village, while the coast is the natural eastern boundary, as shown in Figure 3-1[8]. 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. These voltage levels are used to distinguish between the distinct networks as:

- **Sub-transmission** – 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 sub-transmission 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 sub-transmission voltages for distribution to remote zone substations.

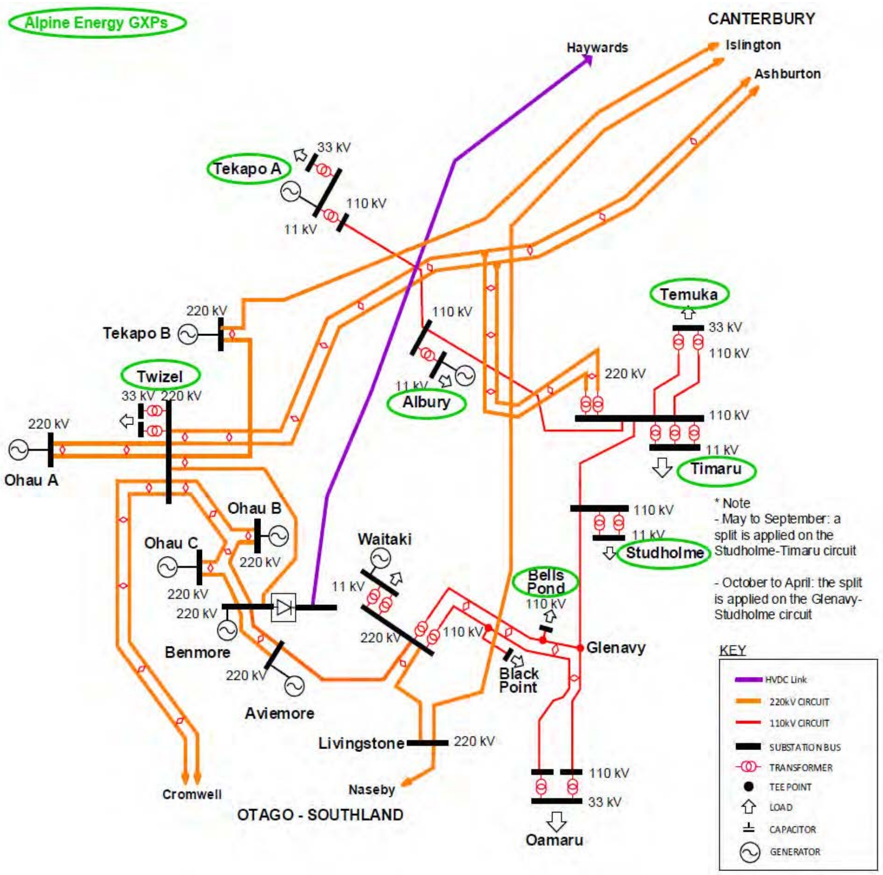
Our network connects to the transmission grid at GXPs, which are the points of interface between our network and Transpower's network. These GXPs operate at voltages of 110 kV, 33 kV and 11 kV at the seven points of supply described in Section 3.3:

Figure 3-1: Our network area

The transmission grid and GXPs supplying our network are depicted in Figure 3-2.

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

Figure 3-2: Transmission grid and GXPs



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[9] capacity except when the overall demand or load criticality does not justify the expenditure to have such a security of supply. An example of this is Albury and Tekapo. There are also instances where the load growth mainly due to dairying has resulted in the erosion of any secure capacity at some GXPs. Examples of these are Studholme and Temuka. At Tekapo, GXP capacity erosion has mainly been due to subdivisions and commercial development in the Tekapo township. More details of these GXPs are discussed in Section 5.9.

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 standardising network equipment over time.

This section provides an overview of all our regions. Our seven planning regions form the basis for our asset management planning function. Further details on these areas can be found in Section 5.9. Table 3-1 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	1,685	6,40	3,346	990	6,957	18,392	1,689
O/H (km)	589	197	550	253	920	940	61
U/G (km)	30	22	46	74	148	478	53
Zone subs	2	3	1	6	5	3	1
Peak demand (MW)	4.2	14.9	15.1	5.1	56.6	65.5	4
Energy consumption (GWhr)	22.7	57.6	68.2	17.6	295	360.4	14.6

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, beef and dairy farming.

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

[9] See definition of security in Table 4-7

supply is considered secure with adequate capacity to meet a small growing demand, as detailed in Section 5.9.1.3

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 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 5.9.2.3.

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 through subdivisions and commercial developments, 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 an average to good condition with some major upgrades and replacements expected in the next five years. The supply is considered secure with adequate capacity to meet the growing demand, as detailed in sections 5.9.4.3 and 5.9.7.3 respectively.

Initial dairy conversions and irrigation developments have stopped 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 seven years old. The two Clandeboye substations are twenty and thirteen years old respectively. Geraldine substation is the oldest, which we refurbished and upgraded during 2021. The supply is considered secure at Rangitata, Temuka and Clandeboye with adequate capacity to meet a small growing demand, as detailed in Section 5.9.5.3.

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.

The townships of Geraldine and Winchester are on single security through the overhead lines that supply them. The supply security is continually reviewed against our *Security of Supply Standard*.

3.3.5 TIMARU REGION

The Timaru region encompasses mainly Timaru City, and therefore most of the load is residential. The Timaru port with the Washdyke area constitutes light industrial and commercial load, dominated by cool stores 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 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 seven years with a new switchboard and new supply transformers and is in excellent condition. We are planning some replacement expenditure in our zone substation supplying Pareora and Pleasant Point. The distribution feeders are in a good condition, and we are in the process of a network upgrade to increase capacity to the Washdyke industrial area. The supply in this area is considered secure with adequate capacity to meet the growing demand, as detailed in Section 5.9.6.3.

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 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 plan 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 5.9.3.3 for more details.

4 / **Stakeholder Interests**

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 network performance against regulatory standards and infrastructure investments. The uptake of new technologies and in particular PV and EVs in South Canterbury are discussed.

4.2 CONSUMERS

This section details our approach to consumers' requirements for new connections and alterations to existing connections, the service levels 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 reconnecting to our network.

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

We presents the consumer with a number of options, as part of the solution, including:

- design only option – where they can arrange and manage the project themselves using a network approved contractor, or
- a design and construct option – where multiple contractor quotes are presented to the consumer for choice.

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 are developing options for full workflow tools and consumer job creation/visibility on our website. This will allow all parties to track project progress.

We are proud to serve more than 33,000 homes and businesses across the South Canterbury which includes diverse groups of households, businesses and communities. Our customer base includes:

- 17 electricity retailers who operate on our network trading under 19 retail brands
- 33,700 homes and businesses comprising:
    - Residential consumers and small businesses (the "mass-market")
    - Medium-size commercial businesses,
    - Large commercial or industrial businesses.
- 6 directly contracted industrial businesses, including distributed generators
- 3 local councils and 1 regional council

Table 4-1 sets out Installation Control Point (ICP) numbers by category according to our latest information disclosures. It shows the proportion of our customer base in contrast to the volume of electricity used, showing the significant electricity consumption of our larger customers.

Table 4-1: Number of customers (ICPs) and electricity delivered

Customer Type	ICPs	% of total ICPs	Electricity delivered (GWH)	% of total electricity delivered
Mass market	30,524	90.6%	233	29.0%
Commercial	3,015	8.9%	200	25.0%
Large commercial / industrial	161	0.5%	368	45.9%
Total	**33,700**	**100**	**801**	**100**

Our customers are distributed across our network regions. The largest regional concentrations are in Timaru, Waimate, Temuka and Geraldine. The mass-market segment includes our residential customers and small to medium enterprises. The majority of our ICPs are mass-market (90.6%), who account for about 29.0% of electricity delivered through our network.

We have 3,015 medium-size commercial customers. These customers range from medium-size retail and dairy producers through to food processing, the Timaru port, and large manufacturing businesses.

During the past three years, growth across all of our customer segments was in line with historical trends. Our customer connection teams and processes have been bolstered to ensure we meet this growing need and continue to provide good customer service.

More information on our large customers is provided in section 4.4.

4.3 CONSUMER SERVICE LEVELS

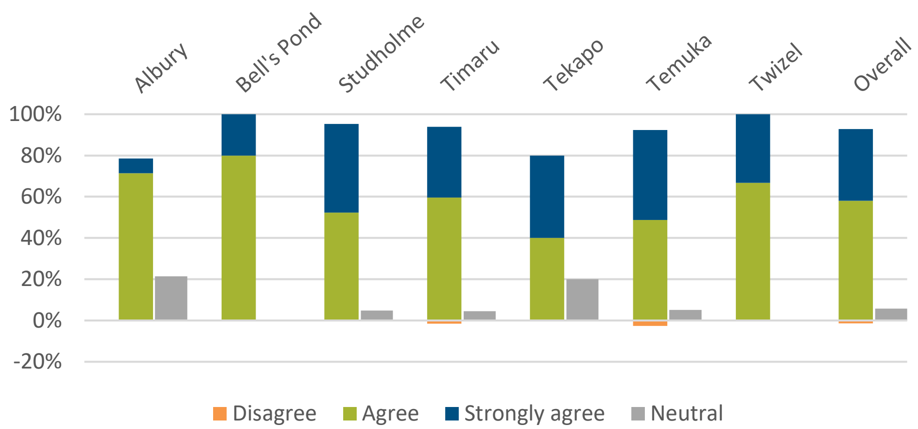
We conduct surveys to establish consumer preferences across a number of different aspects such as outages, responsiveness, asset replacement, electric vehicle uptake, reliability of the electricity supply, and pricing. In 2020, we surveyed 500 mass-market consumers pro-rated across our seven GXPs. The key conclusions were as follows.

- 93% of respondents agreed or strongly agreed that their electricity supply is reliable.
- 86% of respondents would prefer to pay about the same to have about the same reliability.
- 76% of respondents agreed or strongly agreed that unexpected power outages are worse than planned power outages.

- 68% of respondents agreed or strongly agreed that reducing the number of power outages is important.
- 78% of respondents agreed or strongly agreed that reducing the length of power outages is important.
- 86% of respondents agreed or strongly agreed that we should replace parts of the network before they fail.
- 94% of respondents agreed or strongly agreed that advising of planned power outages ahead of time is important.
- 88% of consumers do not expect to purchase an EV within the next five years.
- 60% of respondents would allow us to control their EV charging into cheaper periods.

Below is the detailed responses from consumers measured in percentage across the various GXPs and overall, for the various aspects covered in the survey.

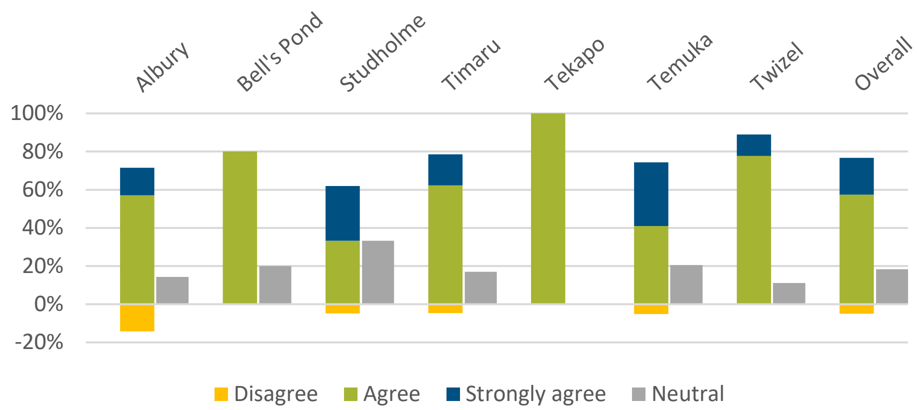
Figure 4-1: Consumer feedback – are you happy with the reliability of your supply?



About 93% of respondents agreed or strongly agreed that their electricity supply is reliable. Only 1% of respondents disagreed that their electricity supply is reliable. Those respondents who disagreed were in Timaru (2) and Temuka (1).

The network reliability is an indicator of the asset management practices employed by all our staff and contractors involved throughout the lifecycle of all assets.

Figure 4-2: Consumer feedback – notified outages are preferred to unplanned outages?



As expected, most consumers prefer planned outage to unplanned outages. It is however interesting that a higher percentage of respondents regard the supply as reliable.[10]

About 68% of respondents agreed or strongly agreed that reducing the number of power cuts is important. We will take care to reconcile this with the perceptions of supply reliability, given that 93% of respondents agreed or strongly agreed that their electricity supply is reliable.

Only 2% of respondents (3 in Timaru, 1 in Temuka, and 1 in Twizel) replied that reducing the number of power cuts is not important.

[10] See previous metric.

Figure 4-3: Consumer feedback – is reducing outages important?

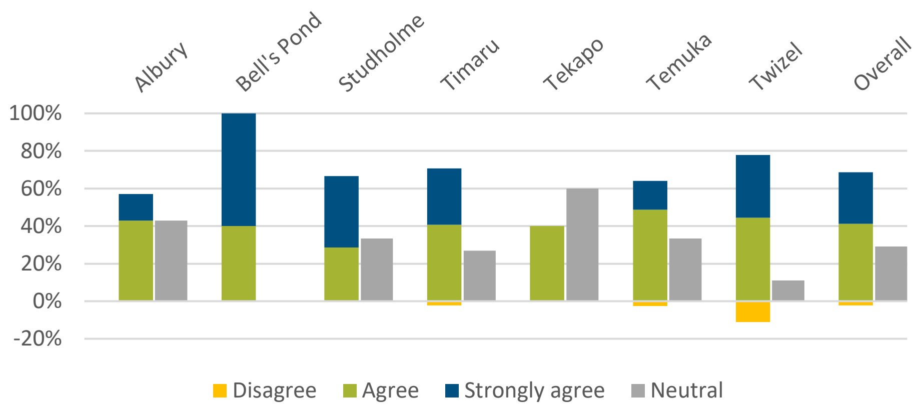
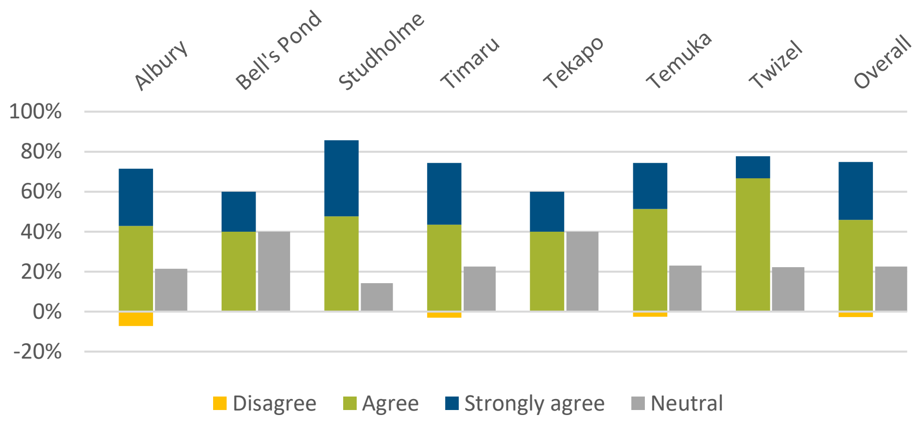


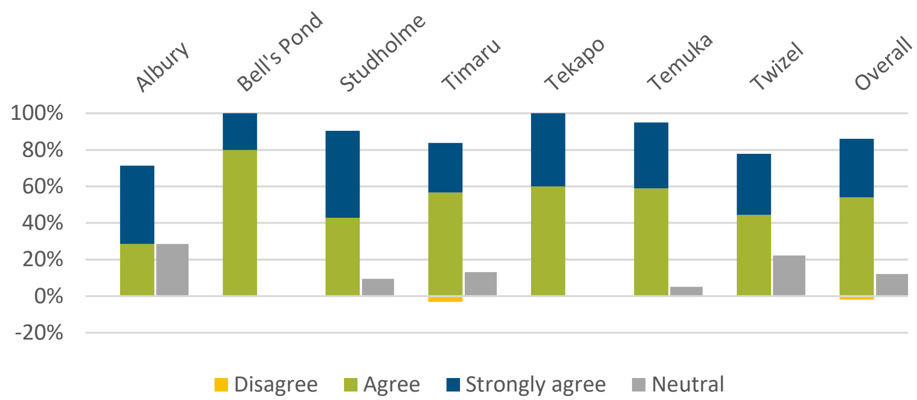
Figure 4-4: Consumer feedback – reducing outage duration is important?



About 78% of respondents agreed or strongly agreed that reducing the length of power cuts is important. Again, we will take care to reconcile this with the perceptions of supply reliability, given that 93% of respondents agreed or strongly agreed that their electricity supply is reliable.

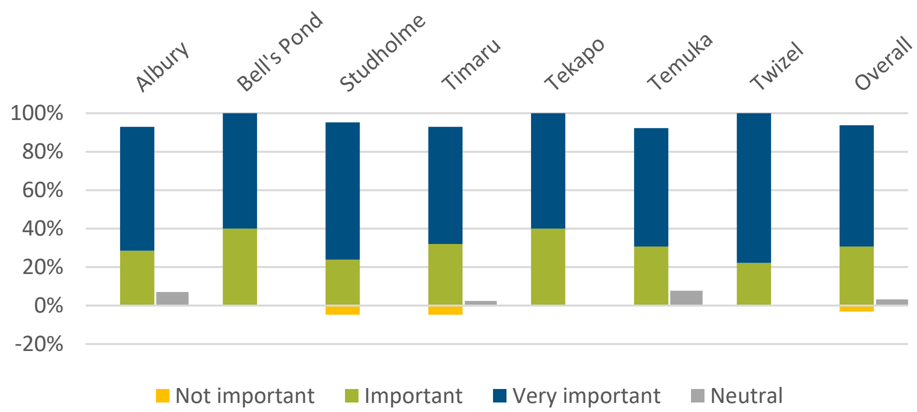
About 3% of respondents (1 in Albury, 4 in Timaru, and 1 in Temuka) disagreed.

Figure 4-5: Consumer feedback – replace assets before they fail?



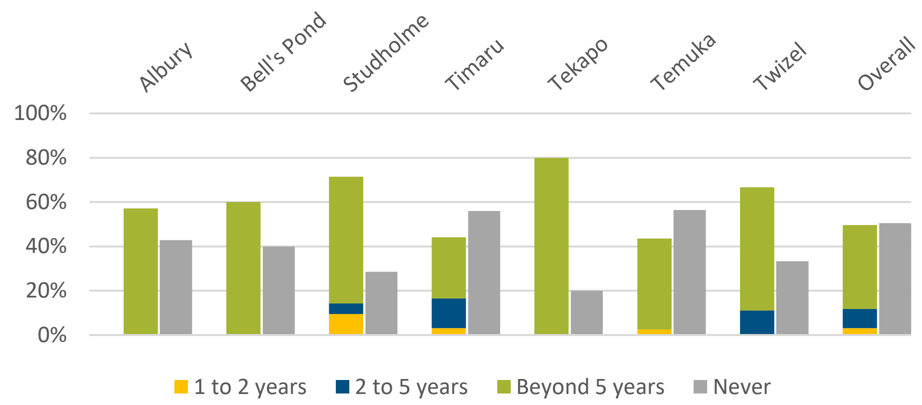
About 86% of respondents agreed or strongly agreed that we should replace parts of the network before they break. Only 2% (4 in Timaru) disagreed.

Figure 4-6: Consumer feedback – how important is planned outage notifications?



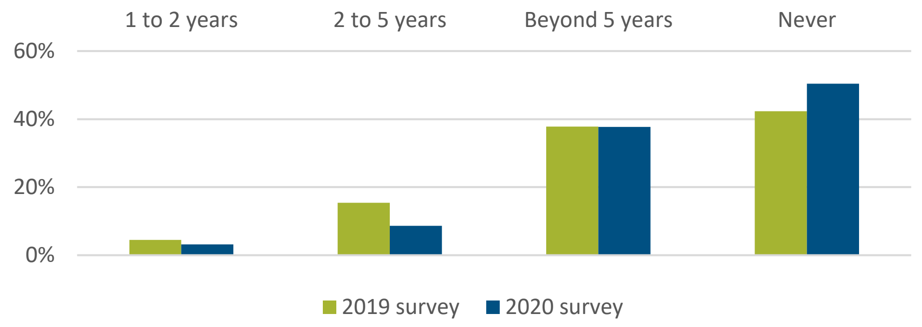
About 94% of respondents agreed or strongly agreed that advising of planned power cuts ahead of time is important. Only 3% (1 in Studholme, and 6 in Timaru) said it is not important.

Figure 4-7: Consumer feedback – likely timeframe for EV purchase?



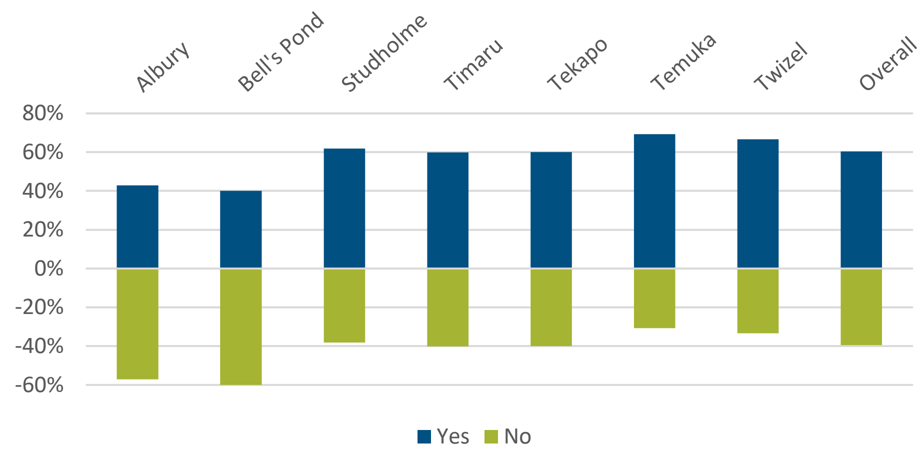
About 88% of respondents do not expect to buy an EV within the next 5 years while 9% of respondents expect to buy an EV within the next 2 to 5 years. Only 3% of respondents expect to buy an EV within the next 1 to 2 years. This represents a distinct decline from the 2019 survey results as depicted in Figure 4-8.

Figure 4-8: EV purchase - Survey results 2019 VS 2020



It appears that within the 16 months since the 2019 customer survey the appetite for buying an EV has declined, including a sharp increase in the number of respondents saying either "beyond 5 years" or "never". This is broadly consistent with wider public sentiment, and also correlates with the quiet acknowledgment of many governments that further EV uptake requires an increasing mix of EV incentives, such as the clean car feebate scheme that the government introduced in 2021.

Figure 4-9: Consumer feedback – will you allow Alpine to control your EV charging?



About 60% of respondents replied "yes". The "yes" responses were lower in Albury (43%) and Bell's Pond (40%) than in the other market segments (which ranged from 60% to 69%). The implication is that about 40% of customers would presumably want to charge any time, potentially adding to peak demand. However, this 40% who presumably would want to charge at any time must also be taken in the context of 26 respondents who expect to buy an EV within the next 5 years. This represents a distinct decline from the 2019 survey results, as depicted in Figure 4-10.

Figure 4-10: Will you allow Alpine to control your EV charging - Survey results 2019 VS 2020

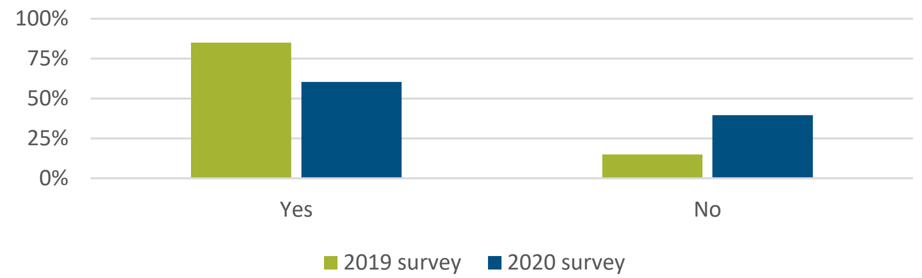
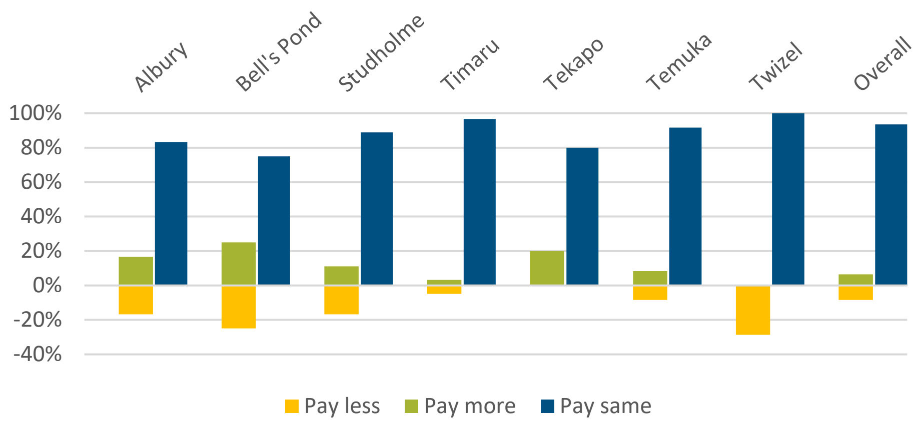


Figure 4-11: Consumer feedback – would you pay more for better reliability?



Consumers were asked three questions to determine their preference for prices and how that relates to power outages. The three questions are listed below with the responses given in Figure 4-11.

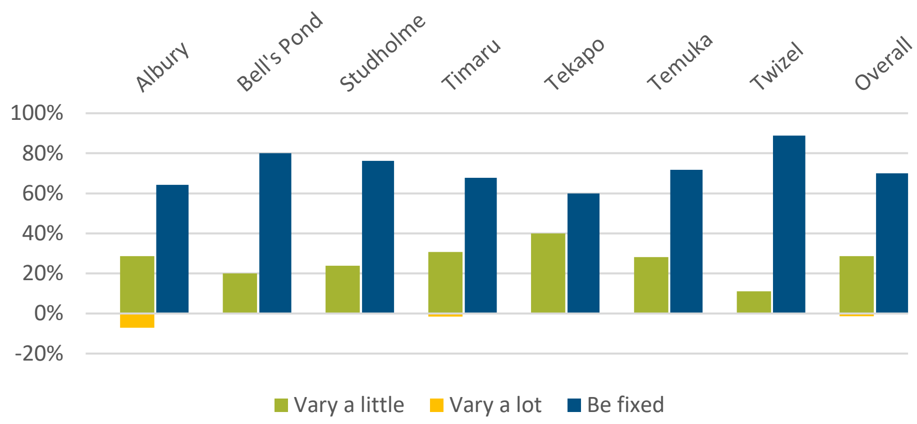
1. Pay a bit less and have the power go off a bit more.
2. Pay about the same to have the power go off about the same.
3. Pay a bit more to have the power go off a bit less

About 86% of respondents would prefer to pay about the same to have about the same reliability; these replies varied across the market segments, from 60% in Bell's Pond to 92% in Timaru.

Only 6% were prepared to pay a bit more to have higher supply reliability, and only 8% were prepared to pay a bit less to have less reliability.

About 70% of respondents would prefer the Alpine component of their monthly bill to be fixed. These responses were spread between 60% (Tekapo) and 80% (Bell's Pond) across all market segments except Twizel, which stood out at 89%. Conversely, only 29% of respondents wanted the Alpine component of their bill to vary a little bit with usage, and only 1% (2 in Timaru and 1 in Albury) wanted their bill to vary a lot with usage. Surveys for other EDB's have indicated that there is still the view that "if I use less, I should pay less".

Figure 4-12: Consumer feedback – would you like your bill to vary with your usage?



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.

Our consumer surveys over the last ten years have indicated that our consumer preferences for price and service levels are reasonably static.

4.3.1 IMPLICATIONS FOR ASSET MANAGEMENT

To give effect to the feedback we have received via our latest consumer survey, we will endeavour to achieve the following:

- Aim to maintain or improve the supply reliability,
- Make optimal use of planned outages to minimise unplanned outages,
- Keep planned outages numbers and durations to a minimum while ensuring the network assets are maintained prudently,
- Continue with our asset replacement and renewal program to ensure assets are replaced before they fail,
- Ensure planned outages are appropriately notified using various means of communication and media,
- Our demand forecasting for the next five years models historic numbers of EV uptake; if more government incentives are introduced that substantially changes the uptake of EVs, we will forecast this load separately,
- When EVs do become more popular, we can expect a fair proportion of consumers will not allow us to control the charging of their EVs, unless we can find some form of incentive to change this position.

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 network and are particularly dominant in the Rangitata, Waimate and Glenavy regions. Most dairy farms are part of either Fonterra or Oceania and they are two of our largest key consumers. 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 to this industry. As a result, most shutdowns for maintenance or network upgrade activities have to be planned for the dairy 'off' season. Installed capacities are detailed in Table 4-2.

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. Future load growth from these industries are foreseen due to the increasing focus on decarbonising process heat. Further conversation with industry covered by our network is helping us further understand the possible extent of this load growth.

Table 4-2: Dairy factory installed capacity

Dairy Factory	Installed capacity
Fonterra – Clandeboye	90 MVA
Fonterra – Studholme	6.5 MVA
Oceania Dairy	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 Table 4-3.

Table 4-3: Irrigation scheme installed capacity

Irrigation scheme	Installed capacity
Waihao Downs	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 have two large meat working plants operating on our network. Details of these are given in Table 4-4.

Table 4-4: Meat works installed capacity

Processing plant	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 from June through to October.

4.4.4 INDUSTRIAL / COMMERCIAL SECTOR

Our large industrial and commercial consumers are mainly located in Timaru. More specifically around the port, Redruth and Washdyke areas. Details of the installed capacities at these plants are given in Table 4-5.

Table 4-5: Industrial/Commercial plant installed capacity

Industry	Installed capacity
Holcim Cement – Timaru Port	6 MVA
McCain Foods - Washdyke	8.2 MVA
South Canterbury By-Products	2 MVA
Coolpak Coolstores	3.45 MVA[11]
Polarcold Stores	4.5 MVA[12]

[11] Approximately 2 MVA is shared with other consumers

[12] Approximately 1.5 MVA is shared with other consumers

Industry	Installed capacity
Juice Products	1 MVA
WoolWorks	2.5 MVA

4.5 COMMUNITIES

Our vision is "Empowering our Community"; which we strive to achieve through our purpose to deliver secure, reliable energy while innovating for our future. We are community owned and proud of it, working with our community and for our community in all that we do. Therefore, our obligation is to be a responsible steward of our assets which prioritises our daily business. We aim to continually act in the long-term interests of our community, utilise our resources to achieve this and fairly disclose our plans and outcomes.

Our electricity network boundaries are from the Rangitata River in the north to the Waitaki River in the south, and from the East Coast to Mount Cook in the west. We supply the communities of Timaru, Temuka, Waimate, Pleasant Point, the Mackenzie Basin and surrounding areas. Directors are appointed to the Board by the communities through the ownership structure.

Our shareholders seek a fair return on their investment, commensurate with the risk of that investment. Creating feasible long-term value through efficiencies, sustainability, prudent financial management, planning and security of supply remain our long-term objectives. Regular reporting and communications help ensure this through structured shareholder reporting, shareholder workshops and the Chair and CEO maintaining regular update sessions with each shareholder group as requested.

We provide 24/7 information during planned and unplanned events on our network via Facebook and our website. This has significantly improved outage-related communication with our community. Various digital technology projects, focusing on consumer information, are expected to be delivered in the near future. Alongside this we are formulating an updated comprehensive Media Plan to further meet our obligation of informing and educating our community, especially with our safety messaging. Our Sponsorship and Personal Grants Programme has been reviewed to ensure our whole community is being efficiently served and across all domains. These initiatives have our community at the core of our mission of 'Empowering our Community'.

4.6 RETAILERS

There are currently 17 retailers operating on our network. Almost 42% 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.

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.

In addition, we also make use of social media and our website to update the community and inform all retailers of planned network outages.

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 of legislative requirements 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 1992
- 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.

We expect to have full legislative compliance. To achieve this target, we manage compliance via an external service provider ComplyWith, that 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.

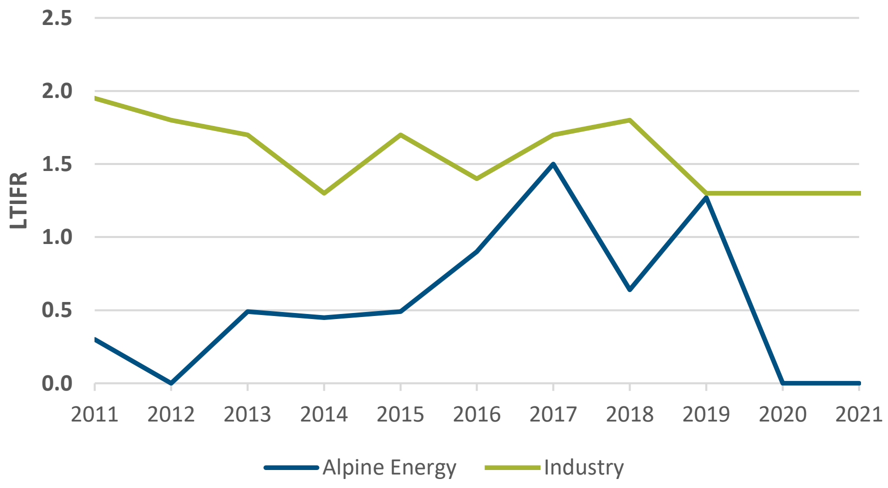
4.9 PERFORMANCE REQUIREMENTS

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 our core values and as such we track and report in detail to our Board on health and safety issues including all events on our network. These events include public, third party and our employee-related events. We track our performance using a number of key performance indicators including lost time incident frequency rate (LTIFR). We benchmark our LTIFR results against the Electricity Engineers Associations year-on-year LTIFR industry average; shown in Figure 4-13 below. Since 2018, we have been including network related contractor lost time incidents in our calculations. From 2019, a lot of effort went into improving our contractor's performance due to the upward trend of LTIs recorded in the 2018/2019 reporting year.

Figure 4-13: LTIFR per 200,000 hrs worked



Sulphur hexafluoride (SF6) is a greenhouse gas, and an excellent electrical insulator used in some of our equipment. The gas is harmful to the environment if there is a leak; therefore we are required to maintain a register of the total volume of gas contained within our equipment, and this is reported annually to the Ministry of Environment to be registered in their inventory. We use specialised and qualified suppliers to fill new and replenish losses in existing equipment.

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 1992 and 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

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 from these meters is a contentious issue. We aim to report on voltage regulation excursions once sufficient numbers of meters are installed and data manipulation has 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.

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 Commerce Commission's quality criteria and is measured through SAIDI and SAIFI indices as defined below.

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 Figure 4-14 and Figure 4-15 respectively.

As shown by the trend line, our SAIDI performance has been improving over the last ten years. Section 7 details improvements made with respect to asset management and capability.

The breach of the target in 2014 was mainly due to the severe windstorm in October 2013 when multiple outages were experienced due to blown over trees and vegetation 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 4-15.

Figure 4-14: Historical normalised SAIDI performance

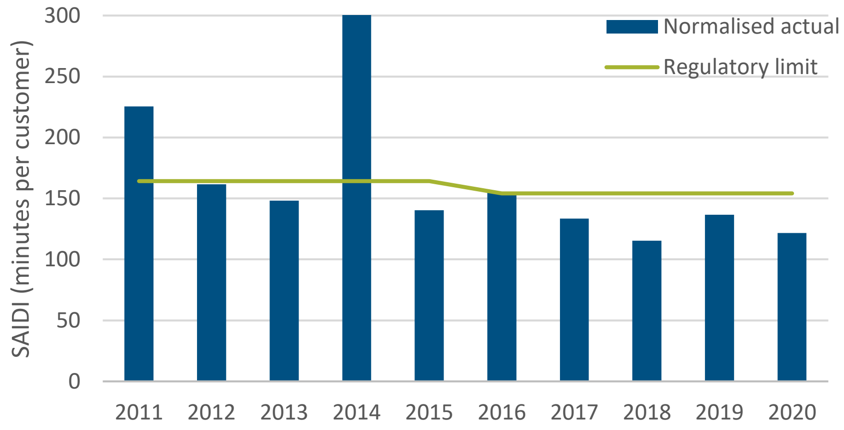
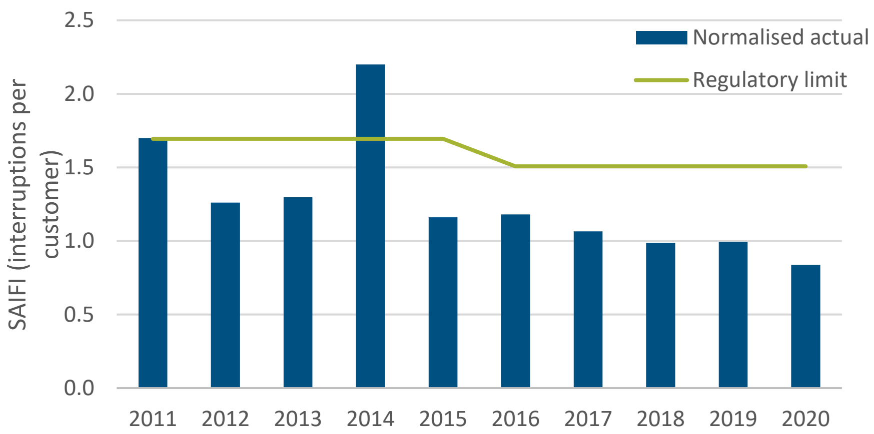


Figure 4-15: Historical normalised SAIFI performance



The commerce commission changed the way in which we report SAIDI and SAIFI against the quality standards in DPP3. From 2021, unplanned and planned interruptions are assessed separately, with unplanned SAIDI and SAIFI assessed annually; while planned SAIDI and SAIFI are assessed over the typical regulatory period of five-year DPP period. Table 4-6 presents our SAIDI and SAIFI performance of 2021.

Table 4-6: Performance against our 2021 SAIDI and SAIFI quality standard

	Security level	2020 / 2021	Regulatory Limit	Assessment Period
SAIDI	Planned	87.55	54.99	5 Yearly
	Unplanned	77.52	91.88	Annually
SAIFI	Planned	0.258	0.699	5 Yearly
	Unplanned	0.635	1.197	Annually

The five-yearly planned SAIDI reliability standard allows us to schedule planned works effectively rather than comply with an annual planned reliability standard. It allows us to manage our planned interruptions appropriately and undertake planned interruptions where it is in the interests of consumers. Our planned SAIDI minutes exceeded the regulatory limit in 2020 because we had a few township projects affecting many customers on multiple days. We plan to recover these minutes in the remaining years of the five-year regulatory period.

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 Table 4-7. This performance requirement also serves as a trigger for investment on our network.

Table 4-7: 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 being able to be restored after ties have been made to other substations. Meaning the lost load will be partially restored (in this example 50%) after switching (reconfiguration of the network) and the remainder of the lost load will be restored in repair time.
N-1	N-1 is the security level that ensures supply after a single contingency event. Meaning no load will be lost due to a single failure.
N-2	N-2 is the security level that ensures supply after two contingency events.

	Meaning no load will be lost due to consecutive failures on two separate circuits.

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

4.9.6 WORKS PROGRAM COMPLETION

This section details our progress against the works program as detailed in our 2021 AMP. In summary, we have completed 90% of our capital works program mainly due to a slower than expected start to the financial year and the impact of COVID-19 on our staff and service providers. Projects not completed is scheduled for the 2022/23 financial year. We have however also completed all overhead line replacement and renewal projects that were deferred from the previous financial year.

Table 4-8 lists the material capital projects completed.

Table 4-8: Material projects completed

Project	Description	Total cost & variances
Ambler Road	Reconductor 2.8km of line.	$205 k No material variances.
Broader Timaru CBD area	Replace underground substations with above ground equivalents. We plan to replace two to three every year.	$1.2 M No material variances.
Pratts Road	Replace and renew 7.4 kilometres and rebuild 3.1 km replacing copper conductor.	$400 k No material variances.
Three Springs Rd to Kimbell	Replace 1.3km of copper.	$265 k No material variances.
Wai-Iti Road, Timaru James Street, Timaru Marchwiel Street, Timaru	3x Underground sub replacement.	$395 k Variance due to increased scope.
Pentland Hills / Kaiwarua Road	O/H line Replacement & Renewal.	$25 k Variance due to transformers and fuses upgraded.
Hannaton Road, Studholme	O/H line Replacement & Renewal.	No material variances.
Geraldine township feeder	O/H line Replacement & Renewal.	$59 k Variance due to increased scope.
SH 8 Kimbell	O/H line Replacement & Renewal.	$67 k Variance due to increased scope.
Timaru Sub to PLP	O/H line Replacement & Renewal.	No material variances.
Mt Nessing Rd, Albury	O/H line Replacement & Renewal.	No material variances.
Softwood pole replacements	O/H line Replacement & Renewal.	$40 k Variance due to increased scope.
Strathallan Street, Timaru Cains Terrace, Timaru Stafford Street, Timaru	13x Lucy box Asset Replacement.	$7 k Variance due to increased scope.
T2 11 kV Switchboard Arc Flash Venting	Reliability, Safety & Environment.	$107 k No material variances.
GLD Transformer Install	Upgrade (replace) the 5 MVA transformer with a 9/15 MVA transformer.	$990 k No material variances.

Our maintenance program for the 2020 AMP was 80% completed, as the COVID-19 pandemic delayed some works. The majority of the monthly and yearly inspections have been completed. Some five-yearly RMU maintenance is still outstanding, but we have caught up with the previous years' outstanding work. These projects have been scheduled for the next financial year, and we are reviewing our maintenance schedules to prioritise our critical maintenance works better.

4.10 NEW TECHNOLOGIES

This section reflects on the current situation in South Canterbury with respect to the connection of distributed generation, mainly PV systems, and the uptake of EVs. The distributed generation data is from our internal database while the EV data is available from the Ministry of Transport website.

4.10.1 DISTRIBUTED GENERATION

We recognise the benefits of distributed generation (DG) that arise from reducing costs such as 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 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.

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

The graph in Figure 4-16 shows the historical annual distributed generation capacity and installations connected to our network which reached a peak in 2018 but has somewhat declined over the last few years. The same data is shown on a per GXP basis in Figure 4-17 and Figure 4-18 respectively. As expected, the uptake is largest in the higher populated urban areas.

Figure 4-16: DG added to our network annually

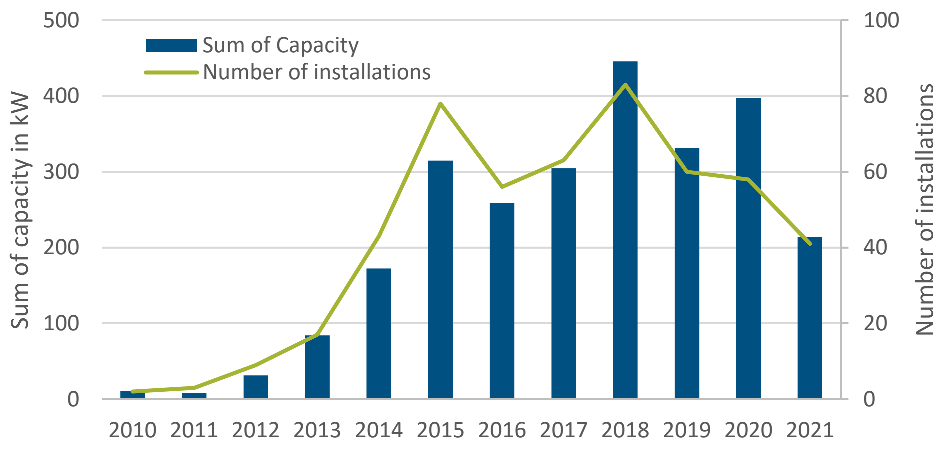


Figure 4-17: DG - accumulated installations by GXP

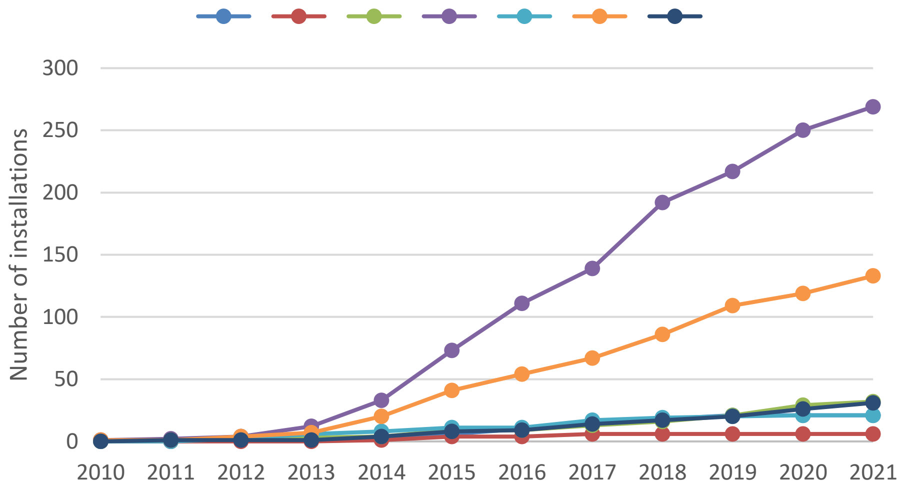
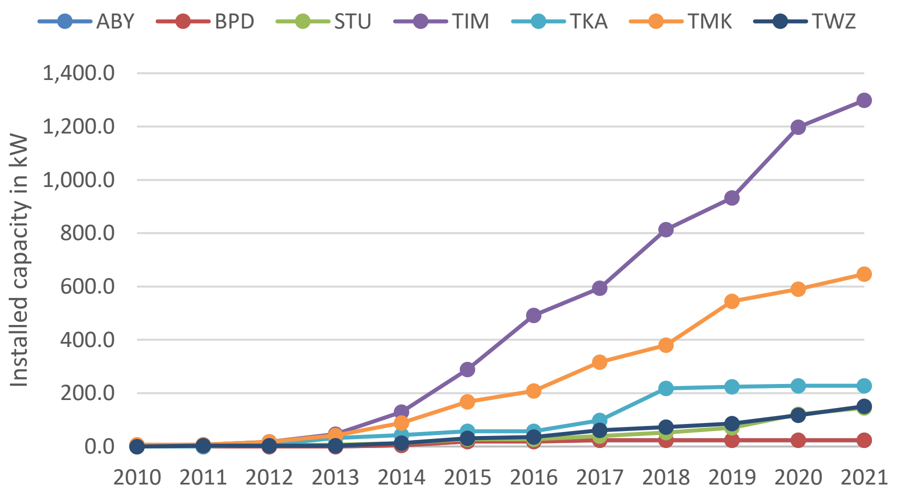


Figure 4-18: DG - accumulated capacity by GXP



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

4.10.2 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 *Whakamana I Te Mauri Hiko – Monitoring* report for September 2021, it is forecast that New Zealand's electricity energy consumption could grow by as much as 60% in 2050. The statement is based on the Climate Change Commission scenarios and a number of assumptions of which the main ones that would affect how we deal with this challenge are:

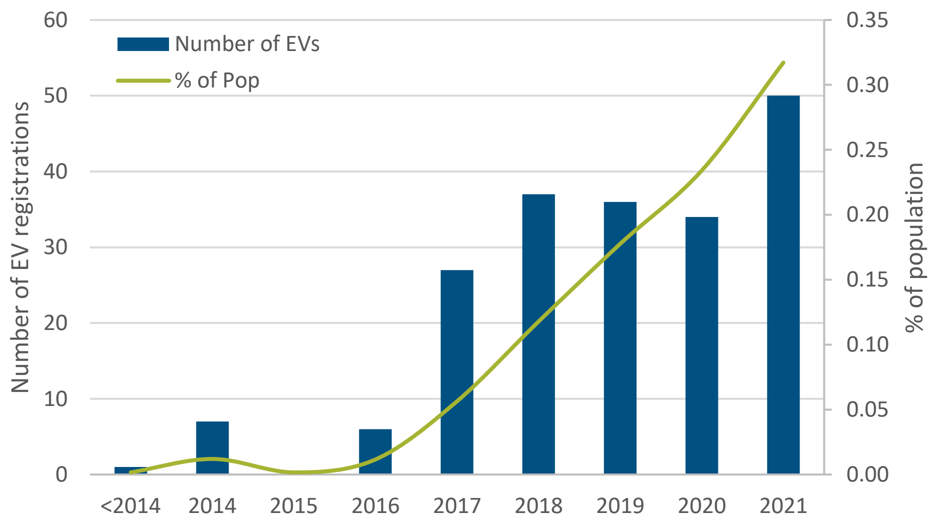
- the assumption that EVs reach ~40 per cent market share by 2030 and ~85 per cent by 2050
- EVs will be cheaper to run, cheaper to buy, cheaper to maintain, and will have a longer lifespan than internal combustion engine vehicles

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.

The current[13] reality in South Canterbury is reflected by the graphs depicted in Figure 4-19 and Figure 4-20, respectively.

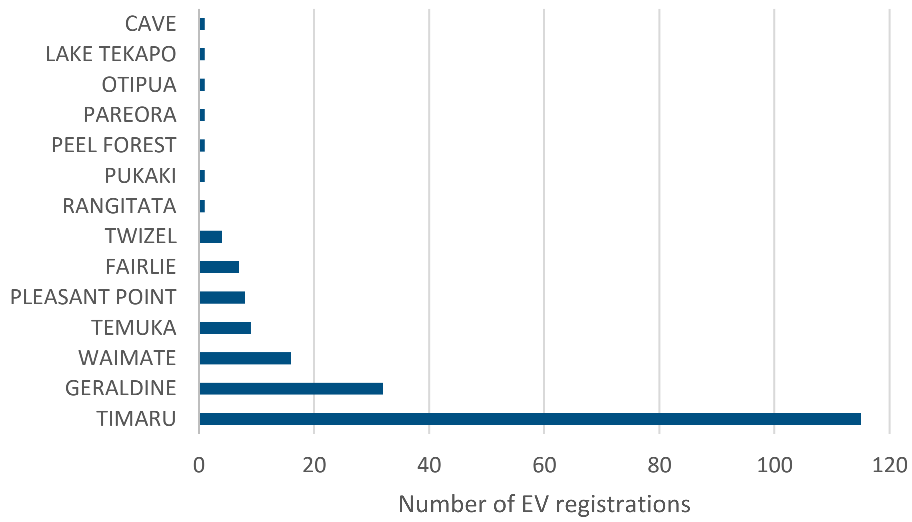
Figure 4-19: EV registrations in South Canterbury as at 11/2021



[13] Data depicted in graphs are up to November 2020 from the Ministry of Transport website.

The data clearly shows that the uptake of EVs in South Canterbury although modest, has increased markedly due to the government subsidies as depicted in the 2021 data in Figure 4-19. This is a move away from our 2020 consumer survey where the appetite for EV purchases were low. The other significant factor to consider is that highly populated urban areas will take-off first as depicted by the number of registrations in Timaru versus the other towns. This strongly aligns with the data for other regions in the country.

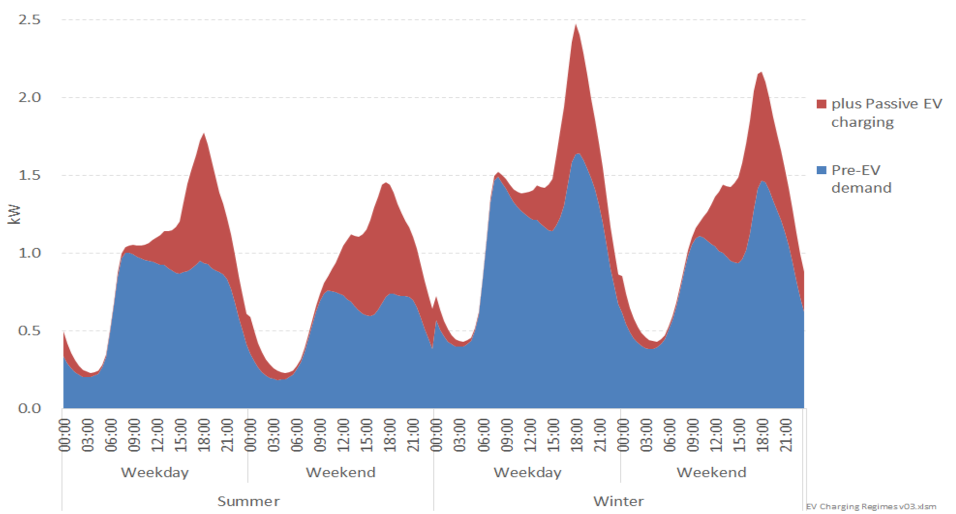
Figure 4-20: EV registrations in South Canterbury as at 11/2020



We agree with Transpower's *Te Mauri Hiko – Energy Futures* report and the subsequent 2019 fourth quarter review 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 the natural behaviour for most EV owners will be, unless they have good information and incentive to do otherwise, to start charging their EVs as soon as they park them at home each evening, so that charging will coincide with the current peak evening demand. This would double the current peak demand.[14] This doubling is also predicted in a report[15] prepared for Orion, Unison and Powerco and depicted in Figure 4-21.

In many cases this increase in demand cannot be accommodated by the existing infrastructure without an EV charging management solution. 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 play an important role in this regard. A controlled or active EV charging profile would then look as depicted in Figure 4-22. From this it is clear that there is a limited and manageable increase in the peak demand.

Figure 4-21: Passive pre- and post EV charging (source: Concept Consulting Group Ltd – Report prepared for Orion, Unison and Powerco, 7 March 2018)

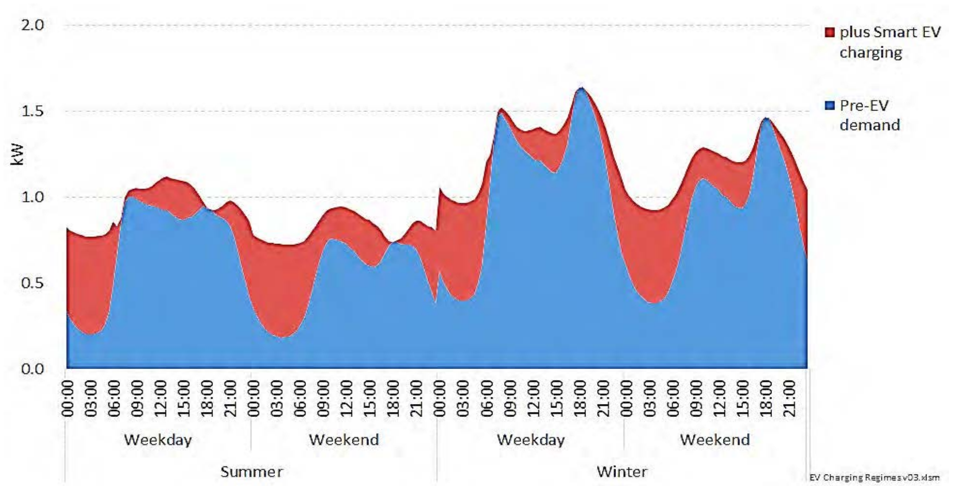


Another area that can be investigated is the effect of pricing signals to influence consumers' EV charging behaviours. The Concept Consulting Group report referred to above, makes the following conclusions:

- "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 a New Zealand paper[16] published in 2020, a sample of 50 EVs were tracked to obtain insights into the potential effects of a dramatic increase in domestic EVs on the New Zealand electricity grid. The study attempts to determine how much of the EV charging occurs during the evening peak demand periods (evening), and to what extent the pre-charged energy in the vehicle batteries could be used to support the grid during peak system demand periods.

Figure 4-22: Smart pre- and post EV charging (source: Concept Consulting Group Ltd – Report prepared for Orion, Unison and Powerco, 7 March 2018)



The results of this study show that standard charging events dominated and mainly occurred in the evenings from 8 pm onwards through to 8 am as depicted in Figure 4-23. There is little difference between weekends and weekdays for standard charging, which is dominated by early morning charging. Existing tariff schemes drove this consumer behaviour, although it is a small sample size, but as stated above, this type of load profile can be managed using existing ripple control technology and/or utilising the functionality of advanced meters. The charging patterns compare well with similar studies done internationally.

Another interesting finding in the study relates to the level of charge left in the EV batteries when connected to the network for charging. On average and for standard charging regimes, EVs had 50% pre-charge energy left in them when connected for charging. This was also constant across all

[14] How Electric Vehicles and the Grid Work Together, IEEE Power & Energy Magazine, November/December 2018.

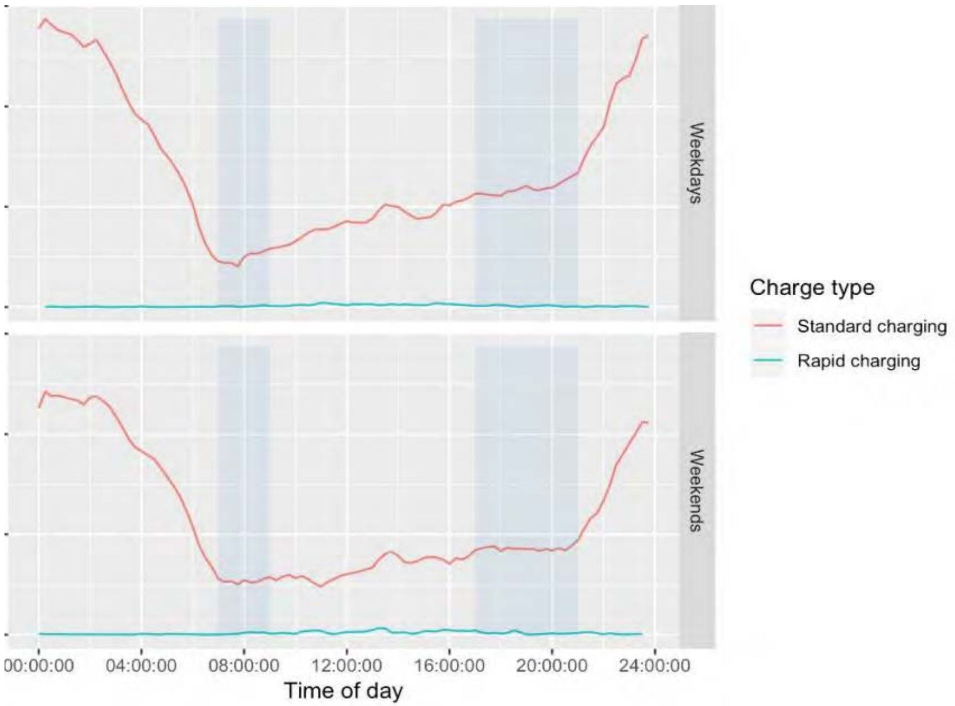
[15] "Driving change" – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand, 2018. A report prepared by Concept Consulting Group Ltd for Orion, Unison & Powerco.

[16] *Will Flipping the Fleet F**k the Grid?,* - Paper presented in Proceedings of 7th IAEE Asia-Oceania Conference 2020: Energy in Transition, 12-15 February. Auckland, New Zealand by Ben Anderson, Rafferty Parker, Daniel Myall, Henrik Moller, and Michael Jack.

time periods. The state of charge for rapid charging scenarios were less at around 43%. This data is illustrated in Figure 4-24.

This is a significant finding, because it predicts that using remaining charge in connected EV batteries, to support the electricity grid during peak load periods, is feasible using smart charging technology. Incentives and pricing schedules will advance this functionality further.

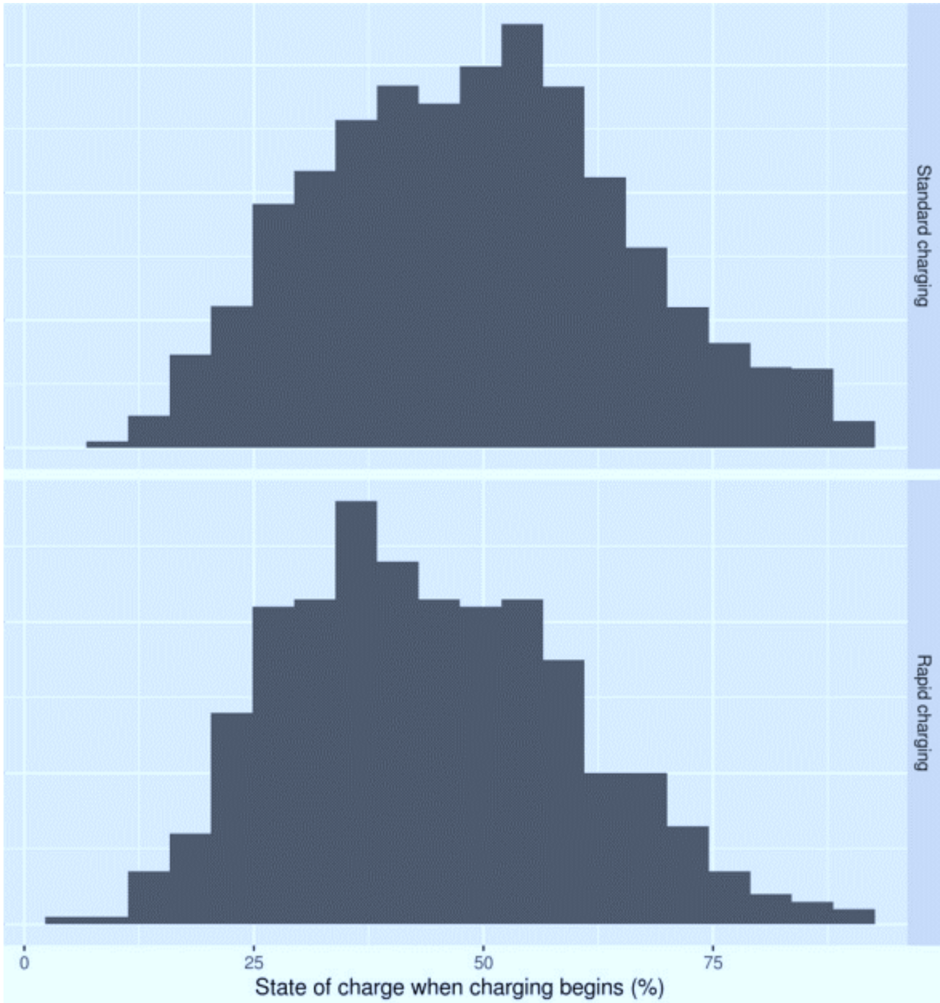
Figure 4-23: Daily charging patterns for standard & rapid charging[17].



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 for 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 to calculate the effects of PV penetration as well as EV charging scenarios,
- continue to participate in national forums on this topic staying current with local and international studies.

Figure 4-24: Value of State of Charge at the beginning of charging sequence.[18]



We recognise the fact that South Canterbury is a tourist destination and also a detour for many tourists to other South Island destinations. As such we will also be focussing our attention on EV charging stations and capability along the main tourist routes such as Geraldine, Tekapo, Twizel and

[17] Source: *Will Flipping the Fleet F**k the Grid?*, - Ben Anderson, et al.

[18] Source: *Will Flipping the Fleet F**k the Grid?*, - Ben Anderson, et al.

Mt Cook to ensure sufficient charging supply capacity is available on our network. We also continue investing in charging stations across our network.

5 / Network Planning

5. NETWORK PLANNING

5.1 OVERVIEW

This section 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 2.5).

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 and new technology solutions. 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 by the General Manager – Asset Management

Our network planning is done across 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 demand in our area relate to weather, demographic growth and economic activity. Another large driver is the decarbonisation activities driven by a desire to reduce the impact of climate change[19] and Government policies. This includes electrifying process heat and transport energy.

Economic activity in our area of operation strongly influences the configuration of our network. In addition, our performance targets and service delivery standards dictates our decisions guiding our 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, influence our 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.

The commercial activity is strong in township centres (CBDs), Washdyke and Port areas. The 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 new subdivisions in Tekapo and Twizel is now also a driver we use in our forecasting models.

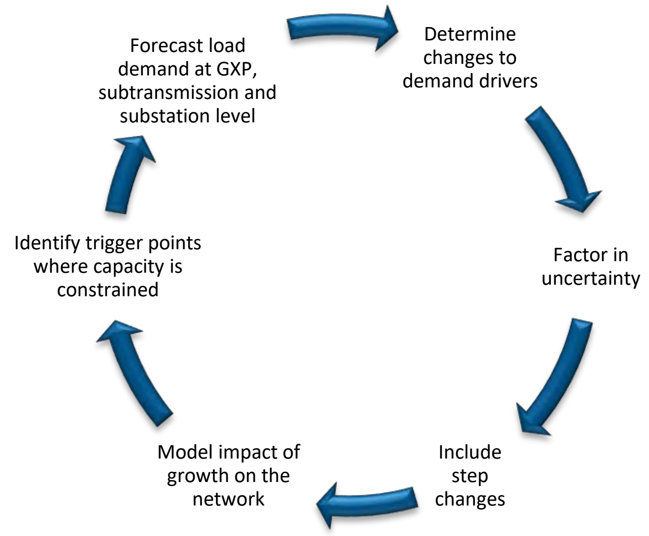
More recently the climate change initiatives by the government has resulted in decarbonisation of existing coal fired boilers for process heat. The GIDI funds have accelerated decarbonisation initiatives, mainly in the Washdyke area.

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

The 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 forms of electric heating.

The impact of other factors that affect demand are also analysed, including emerging technologies and how they impact growth, decarbonisation and how it might reshape our network topography, and the recent COVID-19 lockdown related alteration of demand.

Figure 5-1: Demand forecasting process



[19] This is guided by the Climate Change Commission's Ināia tonu nei: a low emissions future for Aotearoa first advice to Government on climate action in Aotearoa to 2050

The load forecast at the GXPs and zone substations is established using historical demand data that is extracted from our SCADA system and applied in a linear regression. 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 constraint 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 5.9 .

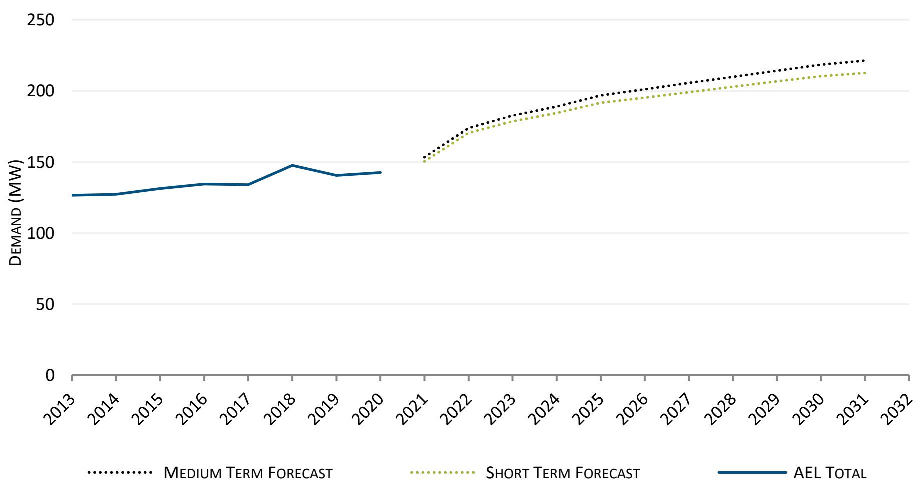
5.2.2 DEMAND FORECASTING

The total energy consumed in 2020/21 was 808 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 143MW[20]. The growth in CPD has been approximately 1.61% per year over the last 10 years.

Figure 5-2 shows the overall network peak demand for the last 10 years and the forecast for the next ten years. Our forecast includes a medium-term forecast based on the last ten years' historical data, as well as a short-term forecast based on the most recent five years' historical data. We use this in all the load forecasting graphs in this AMP.

Figure 5-2: Total peak demand forecast



[20] As reported in our 2021 information disclosures

Our load forecasting graphs have a legend depicting some or all of the following trends:

- Branch limit of the lowest rated equipment/branch in the supply chain
- N security has the meaning as defined in Section Table 4-7
- N-1 security has the meaning as defined in Table 4-7
- Historical actuals
- Short term forecast
- Medium term 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.

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 (SOS)	Projects that ensure our network assets comply with our *SOS 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.

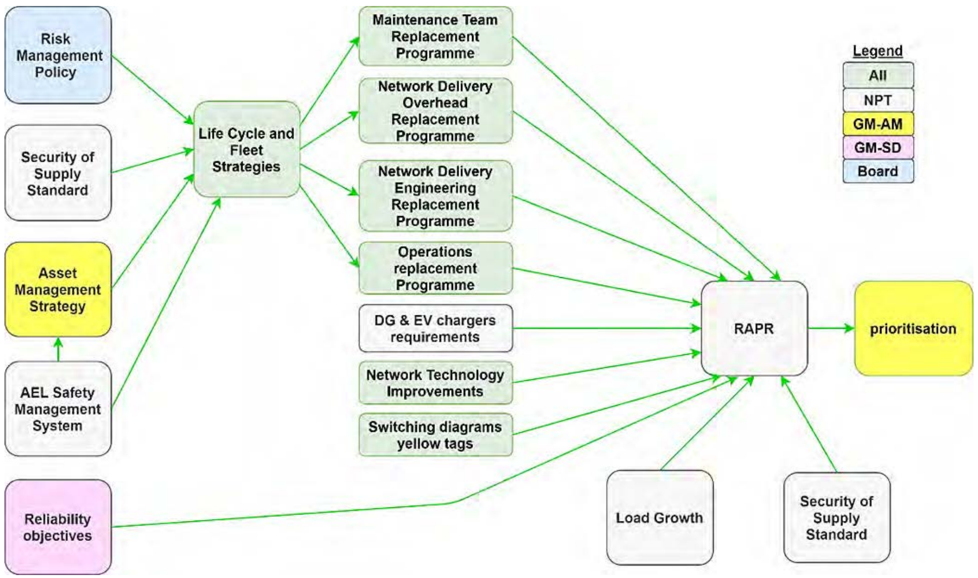
The tools are in place, but a formal prioritisation process has not been implemented yet. Our intention is to move our project administration to the Technology One Project Lifecycle Management (PLM) module, and the dates for the operationalisation of this module have not yet been communicated. Refer to Section 7.4.7 Future road map.

5.3.1 INVESTMENT TRIGGERS

There are several other investment triggers for network investment projects:

- Health and Safety (public, staff and contractors)
- Not meeting stakeholder (consumers) expectations
- Non-compliance with our SOS Standard
- Exceeding equipment ratings (including SCADA alarms and protection settings)
- Insufficient quality of supply (voltage levels, harmonics, flicker, power factor)
- Replacement and renewal
- Environmental
- Governance

Figure 5-4: Regional development plans inputs, process, and responsibilities



5.3.2 OPTION 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 describes 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.	Reconfiguration of distribution feeders by using alternative normally open points or shifting load from one feeder to another.
Non- asset solutions	Use the existing assets in a more effective and efficient way. It also includes third party solutions (sometimes revert to as Non-Network solution).	Balancing the ICP connections across all three LV phases. Update SCADA alarms. Behind the meter solutions (e.g., Solar panels with batteries, smart EV chargers using the electric vehicle batteries to supply back into our network)
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 engineers based on risk management criteria.

5.3.3 NON-NETWORK SOLUTIONS

In addition to network solutions, non-network energy management 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 (behind the meter), both renewable (PV, Wind, hydro, biomass) and non-renewable (diesel generation)
- Energy storage (batteries, heat or water storage), both behind the meter applications and distribution connected applications.

The roll out of smart meters may make these solutions more practical and effective in future. The non-network solutions may be provided by third parties.

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 the existing and expected future consumer load.

We do this by several approaches:

- Proactively analysing the performance of our 33 kV sub-transmission and 11 kV distribution feeders using a digital twin of our network[21]
- Progressing consumer inquiries for new or increased capacity with engineering investigations
- Investigating consumer feedback and complaints
- Conducting specified studies addressing operational issues, for example exploring new back feed options
- Monitoring national and international applications of emerging technologies.
- Closely following the developments of decarbonisation (such as GIDI fund allocations)

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 conductor upgrades, and new feeders.

5.4 SYSTEM GROWTH & SECURITY

5.4.1 CONSUMER EXPECTATION

In our planning, we consider our consumers' expectations. If these expectations change, they may trigger a network investment. The sources of consumer expectations are:

- The consumer requests for new or additional load.
- The general consumer expectations, which include 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.
- The requirements in the "use of system" agreements with the 17 energy retailers operating on our network trading as 24 retail brands.
- The specific contracts with consumers (for example Fonterra, Oceania Dairy Limited and Opuha Water Limited).

5.4.2 COVID-19 PANDEMIC LOCKDOWNS

We have undertaken a high-level assessment of the impacts of the March-June 2020 COVID-19 lockdowns on our historical and forecasted demand. The general consensus is that the demand has reduced across the network compared to 2019's peaks, with some tourism regions experiencing an influx of demand following the ease of lockdown restrictions.

Before and during the lockdown period the South Canterbury region experienced a shift in the dry season which also contributed to the load profile changes. Figure 5-5 below show the lockdowns impact on the total coincident load profile of the AEL network. The figure illustrates the yearly average half-hourly load demands for the different COVID-19 Levels. It is apparent that the demand during the 2020 COVID-19 Level 4 lockdown period was significantly less than the same period in 2019. Table 5-3 reviews the yearly maximum and minimum half-hourly load demands during the different COVID-19 Levels. Table 5-3 also shows the movement percentage of the 2020 demand when compared to 2019 demand.

Figure 5-5: COVID-19 pandemic lockdown impact on the total AEL network demand

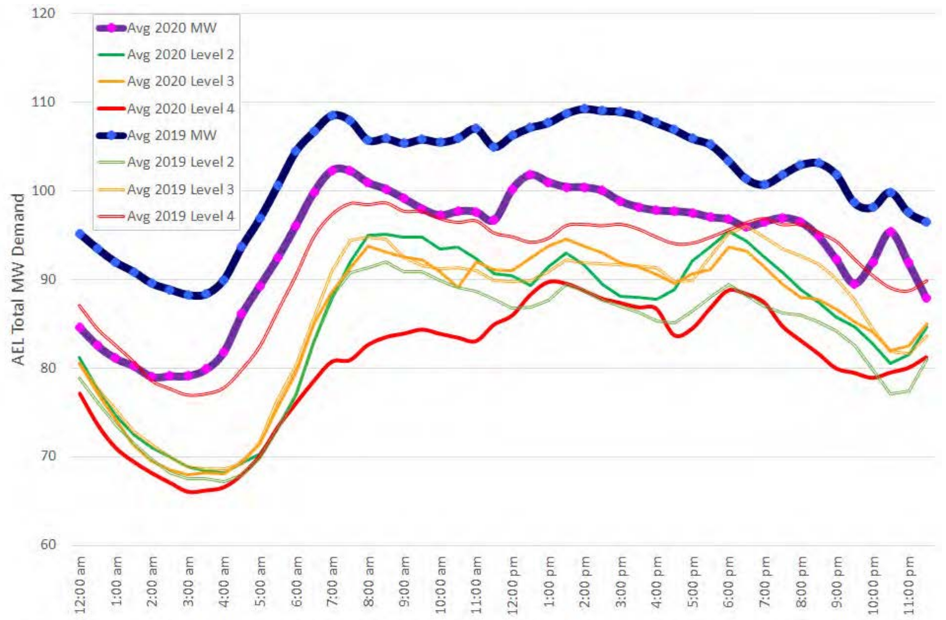


Table 5-3: Demand figures during the different lockdown stages of the COVID-19 pandemic

	All Max	All Min	Level 2 Max	Level 2 Min	Level 3 Max	Level 3 Min	Level 4 Max	Level 4 Min
All Data	130.41	54.28	117.24	54.28	114.14	60.04	122.13	56.67
2019	130.41	54.28	110.19	54.28	107.66	62.38	122.13	65.88
2020	120.05	55.06	117.24	55.06	114.14	60.04	112.15	56.67

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

Movement	-7.9%	1.4%	6.4%	1.4%	6.0%	-3.8%	-8.2%	-14.0%

The dry season shift impact can be seen before, and during, the first level 2 and 3 lockdowns. This resulted in demand increasing by 6.4% and 6.0%, respectively. Another factor that contributed to this increase was the second level 2 and 3 lockdowns, where tourism dominated regions (e.g., Tekapo and Twizel) had an influx of demand due to holiday homeowners traveling to these regions following restrictions easing.

Level 4 lockdown shows an overall average drop in demand of 8.2%. The highest drop in the demand was down to 60.7% and it occurred in early April. The main drivers of this decrease were residential, commercial and tourism type loads. Overall, demand has reduced by 7.9% compared to 2019 levels with a noticeable load profile change.

To avoid a biased demand forecast due to lockdowns impact, we have taken one of the following approaches to adjust the forecast trend.

- Removed obvious low peaks compared to historical peak values
- Applied manual growth rates based on a region's known and expected demand
- Applied a moving average calculation of the biased peak demand based on historical peaks

These were applied based on the feeders' data profile, predominant load type and slope skewness.

5.4.3 SECURITY OF SUPPLY STANDARD

Our security of supply is the defined as the ability of our network to meet the demand for electricity in circumstances when our network equipment fails. A key component of our security of supply is the level of network redundancy that enables the supply to be restored while a faulty component is repaired or replaced. Table 4-7 summarises our security of supply classifications. Our typical approaches to providing security of supply at a zone substation include the following:

- Providing 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
- Providing twin transformers with emergency rating, allowing one to cover the load of the other if one trips or faults
- Providing back-feed on the 11 kV network from adjacent substations where sufficient 11 kV capacity and interconnection exists. Such an arrangement requires that, firstly, the adjacent zone substations have spare capacity and, secondly, that the prevailing topography enables interconnection
- Using local generation (e.g. Opuha dam) or portable diesel generator sets
- Using interruptible load (e.g. water heating or irrigation) to reduce overall load

Security of supply comes at a cost and requires a level of investment beyond what is needed to meet demand.

We also ensure that load growth and any step increases do not erode 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 sub-transmission system, we will strive to achieve a N-1 security level.

It is difficult to set a MW power 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 5.9.

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).

5.5 REPLACEMENT & RENEWALS

When condition assessments indicate that an existing asset is at the end of its 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 its end of life. Substation and plant inspections are undertaken either by the maintenance contractor as part of the routine maintenance programme or as part of a one–off condition assessment inspection by a technical expert. The information from these inspections is collated, reviewed, assessed, and used to inform our asset management decisions.

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

5.6 RELIABILITY, QUALITY, SAFETY & ENVIRONMENT

5.6.1 SAFETY

With safety being our first value, our asset management activities are aligned to ensure our network is safe for the 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 (Electricity Engineers' Association). 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. Safety in design is covered as part of this collaborative effort. Standard designs and industry and international standards form the basis of all our designs. These include the IEC, IEEE, and NZ Codes of Practice amongst others.

5.6.2 QUALITY OF SUPPLY

5.6.2.1 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 change switches (OCTCs), 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, such as (for example) a line upgrade.

5.6.2.2 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.

5.6.2.3 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.

5.6.3 RELIABILITY

We review faults on our network and investigate the causes to determine how interruptions can be reduced or avoided. Our reliability is measured using the system average incident duration index (SAIDI) and system average incident frequency index (SAIFI) in accordance with the Commerce Commission's *Information Disclosure Determination 2012*. Refer to Section 4.9.4 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 the lost consumer minutes (SAIDI) to a fault
- installation of requested asset alterations that increase reliability risk
- increase in frequency and magnitude of extreme weather conditions due to climate change.

Our reliability enhancement programme includes the following steps:

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

5.6.4 ENVIRONMENT

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

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

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

5.7 ASSET RELOCATIONS

LV overhead construction was the traditional method of reticulating urban as well as rural areas in the early days of the New Zealand electricity industry. Most 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.

5.8 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 at the request of a third party. We also do many 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 are funded by the requesting party as a capital contribution.

In the previous two years before the financial year 2020/2021 we have seen a significant increase in residential subdivisions and have had more large-scale subdivisions than previous years. Large subdivisions are rare now in the Timaru. The Tekapo and Twizel areas have seen some subdivisions now completed and more scheduled to start in 2022. 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[22].

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

5.8.1 CLIMATE CHANGE AND DECARBONISATION

One area of significant load growth is that of decarbonisation loads as alluded to in the executive summary in section 1.4.

We acknowledge and are assessing the implications of the global and national efforts to reduce emissions. Aotearoa has committed to reaching net zero greenhouse gases emissions and 24-47% reduction of biogenic methane emissions by 2050. This has resulted in the establishment of the Climate Change Commission to propose future budget pathways to enable such commitment. Other organisation bodies have also followed suit and are producing proposals, guidelines, future roadmaps, and speculations into what the future will hold under such drastic change. Some of these are the Electricity Networks Association (ENA), Ministry of Transport (MoT), Energy Efficiency and Conservation Authority (EECA), Ministry for the Environment and many more. The potential impact of decarbonisation on our load growth and forecasting was not known this time last year. With the introduction of the governments GIDI fund, load increase due to decarbonisation have accelerated. We are assessing, reading research publications and attending workshops produced and organised by most of the above entities to determine the impact on our network.

As part of Aotearoa's commitment, major sectors are starting to gear up to decarbonise their operations, such as Agriculture, Buildings, Industry and Heat, Transport, Forestry, Waste and F-gases (Fluorinated gases) and Electricity.

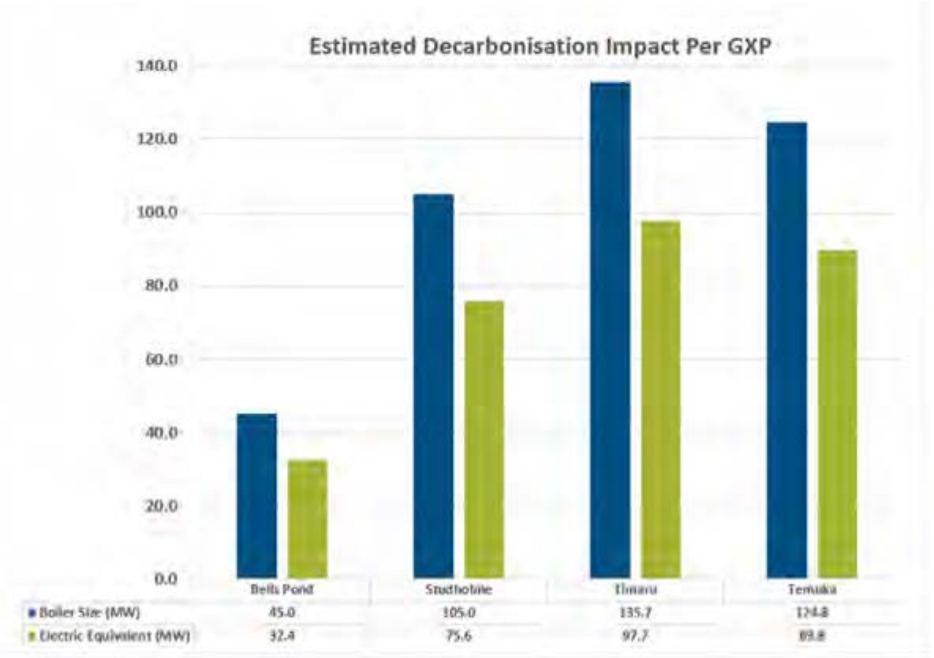
Some of the above sectors will directly impact our network's strategic planning (e.g. Industry and Heat, Transport, Electricity). In contrast, others will either have minimal or no impact (e.g. Forestry, Waste and F-gases). We are observing the impact of electrifying the transport sector globally and will follow closely the actions and proposals of the MoT. It is expected that most major process heat reliant factories will decarbonise, however, we acknowledge that decarbonisation does not necessarily mean electrification. Some consumers might revert to biofuel, hydrogen or other more sustainable forms of fuel based on their operation. Others might electrify their operation with the aid of renewable energy resources to reduce their electricity consumption and consequently running costs.

We are assessing the different types of potential decarbonation scenarios and their impact on our network's growth, security, and reliability. To assist with this, we have engaged EECA and DETA Consulting to assess the implication of decarbonisation in our region. Part of this work was providing a list of potential decarbonisation sites that could impact our load forecasting. Figure 5-6 show the potential energy requirements on our GXPs and zone substations in MW for the alternative case scenario as described in the DETA report and section 1.4. These values are conceptional only and might be lower based on the type of decarbonisation that will be adopted by each consumer. Our expectations are that the real numbers will be lower due to the high demand for biomass in New Zealand. Through consultation with consumers that re looking at

[22] Timaru District 2045 Growth Management Strategy

decarbonising, we know that their corporate requirements include sourcing biomass in close proximity to their operations. Long distance transportation of biomass is not an option for most.

Figure 5-6: Potential electrification growth due to decarbonisation in the AEL region



Because these load increases are step load increases, they remain a challenge planning for them. Most of the load increases are located in Washdyke. If they all come to fruition, we will have to establish a Washdyke 33/11 kV zone substation and at the same time require a 33 kV GXP at Timaru. It is not a matter of if, but when this load will be realised. Load forecast planning for decarbonisation load remains a very uncertain science and any results of load growth can change suddenly through government incentives, government policy, or by a change in government. We are closely following trends in the industry, nationally and overseas, to confirm that we have a sound methodology for load forecasting.

5.8.2 LARGE SCALE DISTRIBUTED GENERATION

During the course of 2021 we received a number of initial applications for the connection of large-scale DG to our network. As noted in the executive summary, these applications total 130 MW of generation capacity. Due to the technical complexities of connecting such a large generating plant to a distribution network, the industry soon realised that the *Electricity Participation Code Part 6*, which deals with DG is not fit for purpose for this scale of generation.

As industry participants, both EDBs and Transpower have been working collaboratively to address the particulars of processing and progressing large-scale DG applications in scope and timeframes that give developers confidence and does not put networks or the national grid at risk. The EEA has led a few national workshops for the industry on this subject through presentations by international speakers who are experts on this subject matter. Transpower has developed a suite of documents that guides developers and EDBs through the process for DG of scale that will impact on the System Operator's ability to manage the national grid. In response, we have also commissioned the development of our own EDB technical standard for the connection of large-scale DG to our network, and a well-documented process for dealing with applications. This will ensure that developers have a clear understanding of the process and technical requirements that would manage their expectations.

We believe it is important to sketch a picture of the reality of large-scale DG applications to connect to our network and the potential implications it has for investments by EDBs or developers. Most of the applications we receive are submitted under a non-disclosure agreement, and therefore we cannot share specific details of the individual applications. Table 5-4 lists non-particular details of large-scale DG applications we received in 2021, including the potential distribution network investment required to effect the connection of this DG to our network.

Table 5-4: Large scale DG applications

No.	GXP	Size (MW)	Connection details	Potential investment
1	Temuka	26	Cable circuit(s), switchgear & protection.	$ 2.6 M
2	Tekapo	9	Switchgear & protection	$ 150 k
3	Albury	6.6	OH circuits, switchgear & protection	$ 400 k
4	Twizel	30	This scale DG will most likely be a direct connection to the national grid	$ 0
5	Bells Pond	20	Cable/OH circuits, switchgear & protection, possible 33 kV bus..	:≈$ 2 M
6	Bells Pond	30	OH circuits, zone substation, switchgear & protection	$ 4-M - $ 6 M
7	Timaru	6.5	Cable circuit(s), switchgear & protection.	$ 500 k

It is important to note that due to the stage of application processing and no signed commercial terms for any of the applications listed above, no capex budgets for these initiatives have been included in this AMP forecast expenditure. If any of these projects progresses to construction, we will submit a request for a reopener with the Commerce Commission or alternatively manage the construction through our capital contributions policy.

5.9 REGIONAL PLANS

This section summarises the network development plans for each of our seven planning regions as depicted in Figure 5-7. Each planning region is supplied by its own GXP from Transpower as shown in Figure 3-2.

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

Figure 5-7: Regional area & GXP map

Material growth and security projects are projects that will increase our network capacity or increase or maintain the required security of supply.

5.9.1 ALBURY

5.9.1.1 OVERVIEW

The Albury region is mainly rural with the predominant farming activity being sheep and beef farming. There are two major townships, Albury and Fairlie; Fairlie being the largest. Fairlie has a commercial area supplying services to the surrounding farms, but it also services 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 generation scheme embedded in our network injecting power at 33 kV.

5.9.1.2 NETWORK CONFIGURATION

The Albury network configuration is described in Appendix A.6.1.

5.9.1.3 DEMAND FORECAST

Demand forecasts for the Albury GXP, and regional zone substations are shown in Figure 5-9 through to Figure 5-11 respectively. Further details are provided in Appendix A.5.

Demand growth is flat and there are presently no known significant step increases from new connections to the network. The forecast step increase in load at both Albury and Fairlie zone substations are based on current new connection supply enquiries on our books that are confirmed or has a high likelihood status. This forecast is based on the proposed transformer supply capacity without any utilisation adjustment and is therefore conservative.

Demand growth because of EV uptake can easily be accommodated on the basis of existing capacity at GXP and zone substation level. Due to the low population density of this area, and based on current levels of EV uptake, we do not foresee any capacity constraints in this region.

We have received a Distributed Generation (DG) initial application for 6 MW in the Albury area. We have not received any information of the likely timeframe for the construction. If this generation is realised, it would potentially increase our ability to respond to any demand increase.

Figure 5-8: Albury GXP supply area

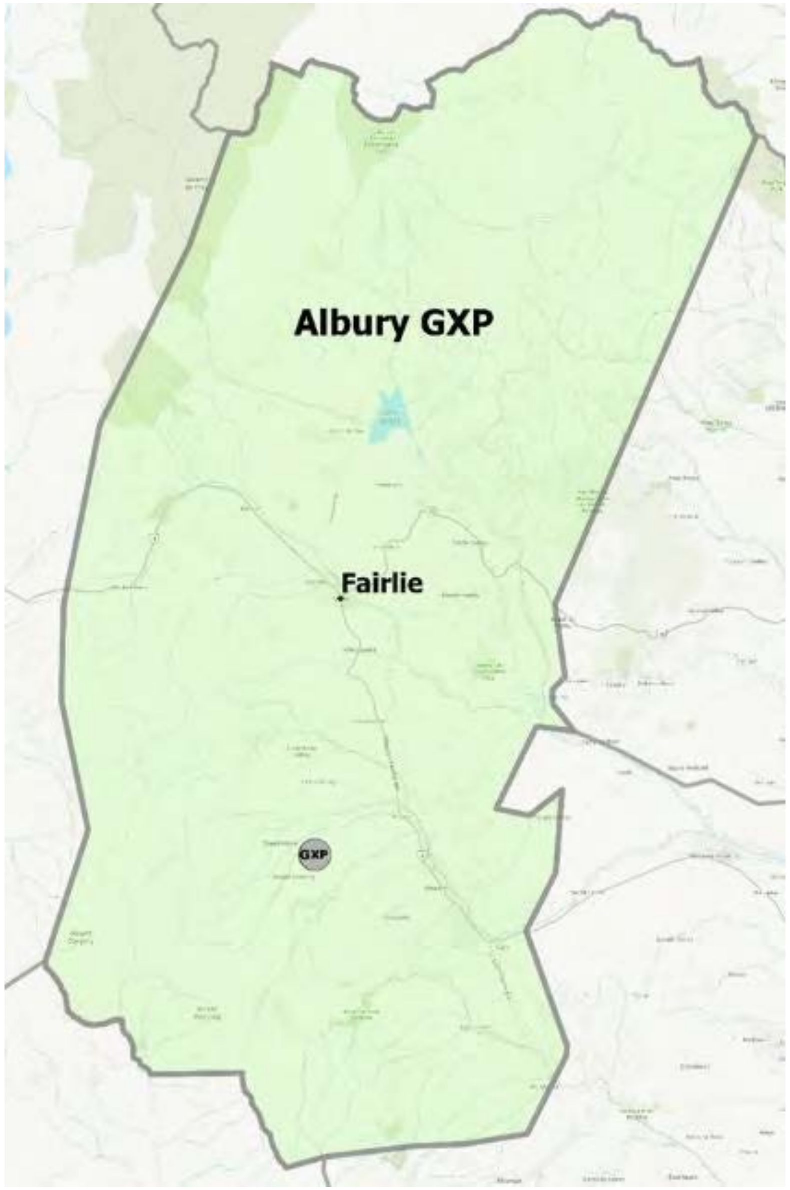


Figure 5-9: Albury GXP load forecast

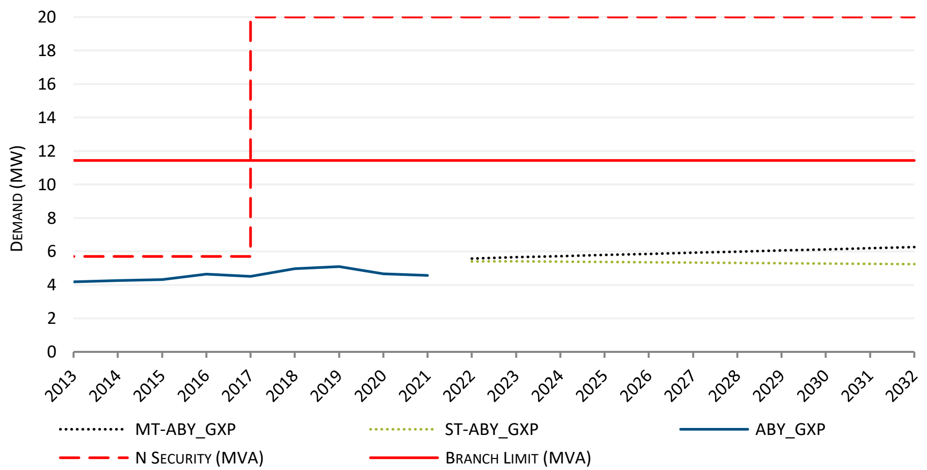


Figure 5-10: Albury zone substation load forecast

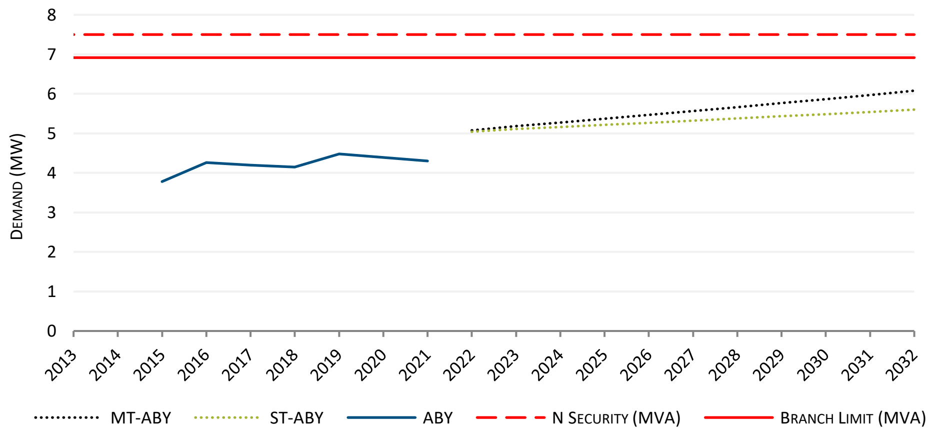


Figure 5-11: Fairlie zone substation load forecast

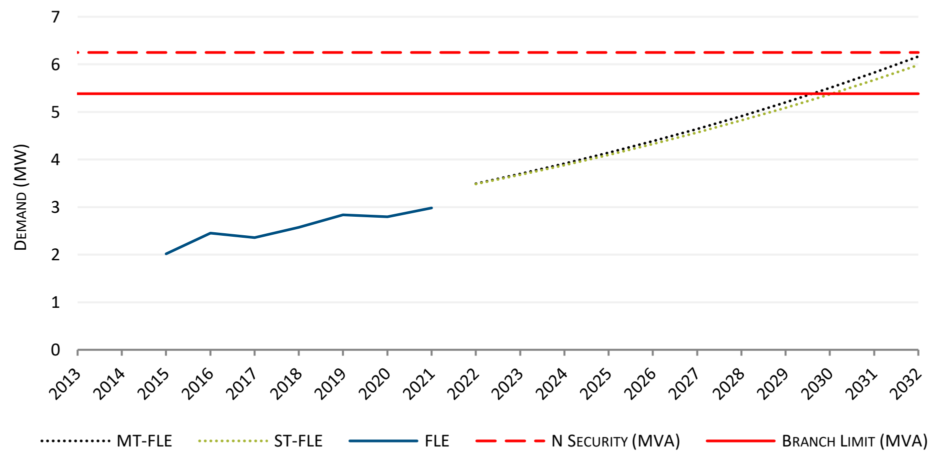


Table 5-5. Albury region demand forecast in MW

Substation	N Security (MVA)	Branch limit (MVA)	2022	2023	2024	2025
Albury GXP	20.00	11.43	4.57	5.55	5.63	5.70
Albury zone substation	7.50	6.92	4.30	5.20	5.29	5.36
Fairlie zone substation	6.25	5.38	2.98	3.48	3.63	3.77

5.9.1.4 SECURITY OF SUPPLY

Table 5-6 Albury and Fairlie security of supply

Zone sub / load centre	Actual	Target	Comment
ABY GXP	N	N	Security target is met for this planning period in accordance to our Security of Supply standard.
			Transpower mobile substation can be deployed at this GXP. Transpower has evaluated this GXP as 'Low Economic Consequence'[23] and hence does not have a target of providing a higher security for it during this planning period.
ABY-FLE 33 kV line	N	N	Security target is met for this planning period in accordance with our Security of Supply standard.
FLE-OPU 33 kV line	N	N	Security target is met for this planning period in accordance with our Security of Supply standard.
ABY 11 kV feeders	N	N	Security target is met for this planning period in accordance with our Security of Supply standard.
FLE	N	N-0.5 SW	Limited fault backup to FLE Zone substation and distribution Feeders. FLE has a mobile generator port that can be utilised during outages.

5.9.1.5 EXISTING & FORECAST CONSTRAINTS

Transpower installed a new 110/33/11 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 11.43 MVA available to us[24]. 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, increasing 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 which results in voltage constraints.

The following backup options are currently available 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 of the Opuha generator. Approval by the distributed generator operator (Trustpower) is required. Therefore the Opuha power station is not considered in any security of supply considerations.

[23] Economic Consequence is the amount of load being served at a Point of Service (POS) multiplied by the VoLL at that POS, and is the expected dollar cost of an unplanned interruption at that POS

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

5.9.1.6 MATERIAL GROWTH AND SECURITY PROJECTS

There are presently no material growth projects or security projects planned for the Albury region. If the forecast load growth is realised through the planning period, we will plan and schedule a transformer upgrade towards the latter part of the planning period.

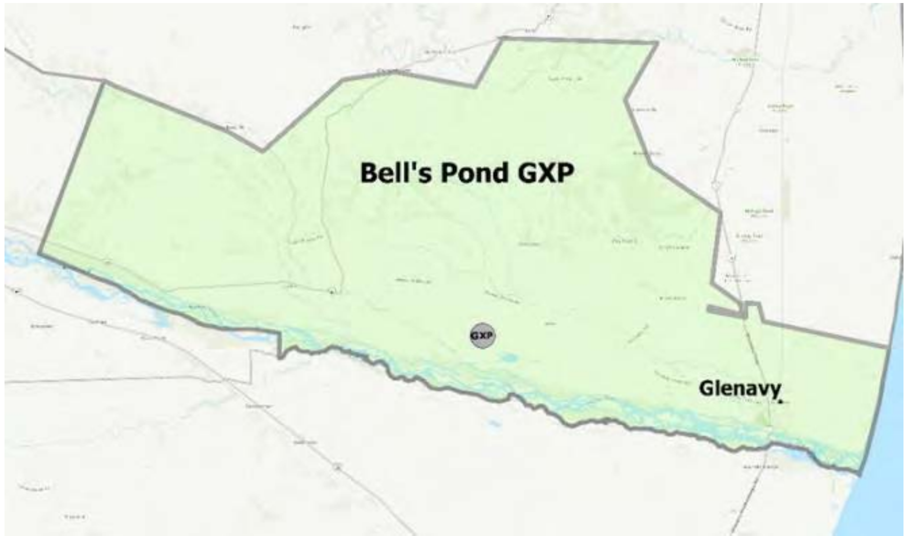
5.9.2 BELLS POND

5.9.2.1 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.[25]

Figure 5-12: Bells Pond GXP supply area



5.9.2.2 NETWORK CONFIGURATION

The Bells Pond network configuration is described in Appendix A.6.2.

5.9.2.3 DEMAND FORECAST

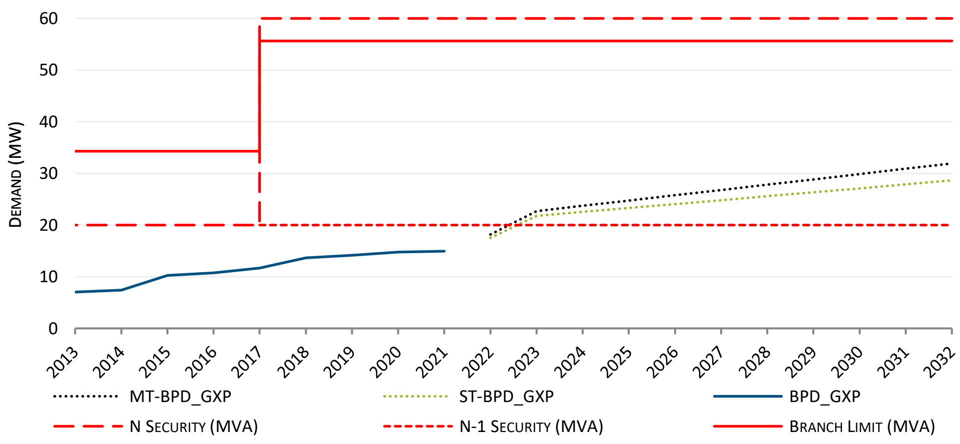
Demand forecasts for the Bells Pond GXP, and regional zone substations are shown in Figure 5-13 through to Figure 5-15 with further details provided in Appendix A.5.

Load growth in recent years has been flat and hence the forecast is for fairly low levels of growth. Most of the load resulting from dairy conversions and irrigation schemes have been accounted for. The forecast load growth is mainly related to border dyke irrigation conversions to pivot irrigators.

The single step change in the load forecast is a result of increased load at Oceania Dairy Limited (ODL) laboratory expansion (1 MW), plus the committed capacity as per the supply contract which may be used for a second drier (3.5 MW).

We have received a distributed generation (DG) initial application for 20 MW in the Bells Pond area. No information of the likely timeframe for the construction is available.

Figure 5-13: Bells Pond GXP load forecast



Demand growth because of EV uptake can easily be accommodated on the basis of existing capacity at the GXP and zone substation level. Due to the low population density of this area, and based on current levels of EV uptake, we do not foresee any capacity constraints in this region.

It is possible that ODL would consider decarbonising their operations which currently comprises 30 MW of fossil fuel heating load. If this is converted to electricity, it would have a substantial impact on our load forecasting and the resultant network augmentation investment required.

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[25] www.mgiirrigation.co.nz

Figure 5-14: Bells Pond zone substation load forecast

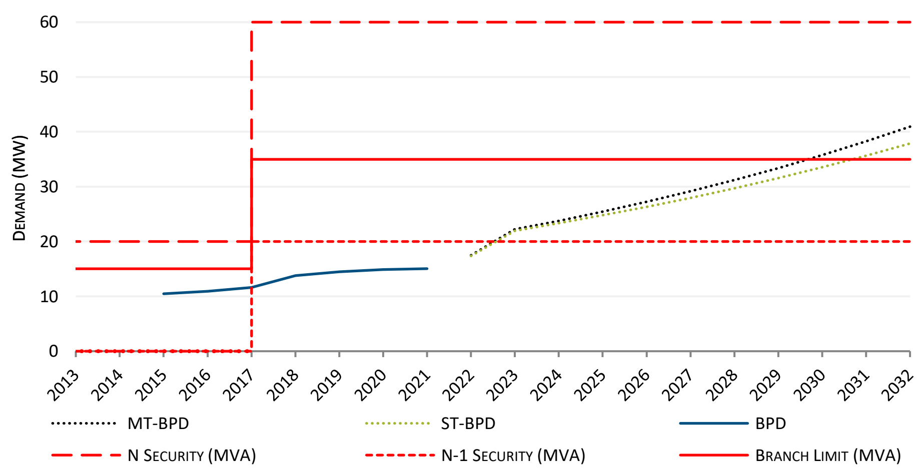


Figure 5-15: Cooneys Road zone substation load forecast

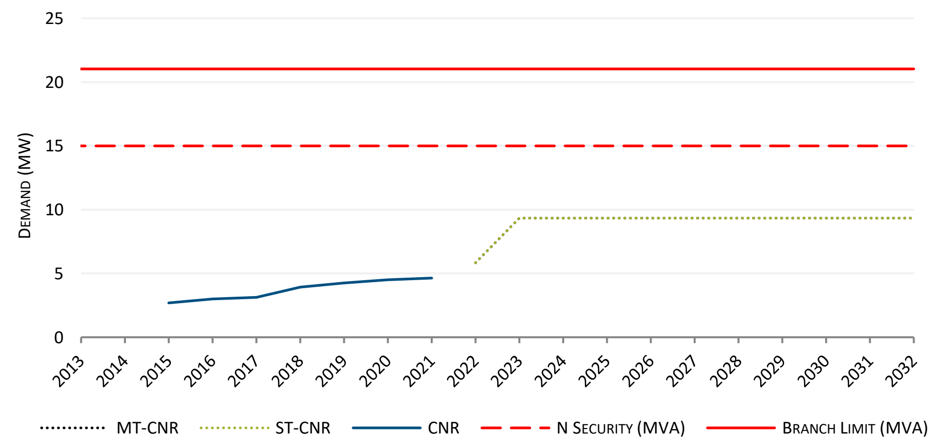


Table 5-7 Bells Pond region load forecast in MW

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025
Bell Pond GXP	60.00	20.00	68.59	14.94	18.17	22.70	23.72
Bell Pond zone substation	60.00	20.00	34.98	15.05	17.90	22.28	23.15
Cooneys road zone substation	15.00		19.43	4.64	6.36	10.21	10.57

The 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 was commissioned initially with a load of 2.6 MVA. An ultra-high temperature treatment (UHT) and canning plant commissioned in 2017 has then increased their total load to around 4 MVA. As the factory grows beyond what Bells Pond can supply at 33 kV, a permanent 110 kV supply will be required.

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

5.9.2.4 SECURITY OF SUPPLY

Table 5-87 details the security of supply for the Bells Pond and Cooneys Road zone substations respectively.

Table 5-8 Bells Pond and Cooneys Road security of supply

Zone sub / load centre	Actual	Target	Comment
BPD GXP	N-1	N-1	Security target is met for this planning period in accordance to our Security of Supply standard. The security level will change to N in FY22. Transpower has transmission configuration changes that would allow some or all supply to be restored. Transpower has evaluated BPD GXP as 'Low Economic Consequence'[26] and hence do not have a target of providing a higher security for it during this planning period.

[26] Economic Consequence is the amount of load being served at a Points of Service (POS) multiplied by the VoLL at that POS, and is the expected dollar cost of an unplanned interruption at that POS

Zone sub / load centre	Actual	Target	Comment
BPD-CNR	N	N	Security target is met for this planning period in accordance with our Security of Supply standard.
BPD (11 kV)	N-1	N-1	Security target is met for this planning period in accordance with our Security of Supply standard.
BPD (33 kV)	N-1	N-1	Security target is met for this planning period in accordance with our Security of Supply standard.
CNR	N	N-0.5	Security target is met for this planning period in accordance with our Security of Supply standard.

5.9.2.5 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 most of the 11 kV load if both Studholme transformers are in service. This spare capacity at Studholme will be eroded should Fonterra build a milk dryer at their Studholme dairy factory (it has 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. 1 MW[27] of back up supply from an adjacent 11 kV feeder from Studholme is available. Further investment will be needed when ODL want to increase security to N-1.

Bells Pond GXP and Studholme GXP currently have a transmission limit imposed by Transpower due to voltage quality and thermal overloading issues during the summer peaks on the Bells Pond-Waitaki and Oamaru-Studholme-Bells Pond-Waitaki 2 circuits.

Transpower has implemented a special protection scheme (SPS) to curtail load if one of the two Waitaki 110 kV circuits is lost. The SPS will, in certain instances, allow us enough time to run our ripple injection plant to shed irrigation load, thereby maintaining supply to dairy processing plants and milking sheds, rather than turning off all load indiscriminately. In addition, Transpower will offload Studholme GXP onto the Timaru GXP with Bells Pond remaining on the Waitaki supply.

5.9.2.6 MATERIAL GROWTH AND SECURITY PROJECTS

This section is a summary of material projects planned for the Bells Pond region. Both projects listed here are dependent on customer requirements for security of supply. The GXP security is a function of our security of supply standard.

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 1 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 sub-transmission feeder circuit breaker at Bells Pond zone substation.

N-1 Security of Supply breach at BPD GXP

Estimated cost (concept)	Estimated cost (concept)
Expected project timing	TBD

Description:

The capacity of the BPD transformer T2 is forecast to be exceeded during peak loads (spring/summer FY22/23) mainly due to irrigation. T2 capacity will need to be increased to maintain N-1 security. Supply security to ODL and most dairy farms can be restored through load control of the irrigation pumps fitted with ripple relays.

Waihuna feeder voltage and growth support

Estimated cost (concept)	Approximately $300 k
Expected project timing	FY 26/27

Description:

Due to the growth on the Waihuna feeder and future steady growth in the region some capacity and voltage support will need to be implemented. Solution options are:

- Upgrading the OH lines.
- Install a voltage regulator at a strategic location on the feeder.
- Install capacitor bank at strategic location(s) on the feeder (preferred option).

Based on the information we currently have; the above upgrades will cater for growth on the feeder in the foreseeable future.

[27] Summer season

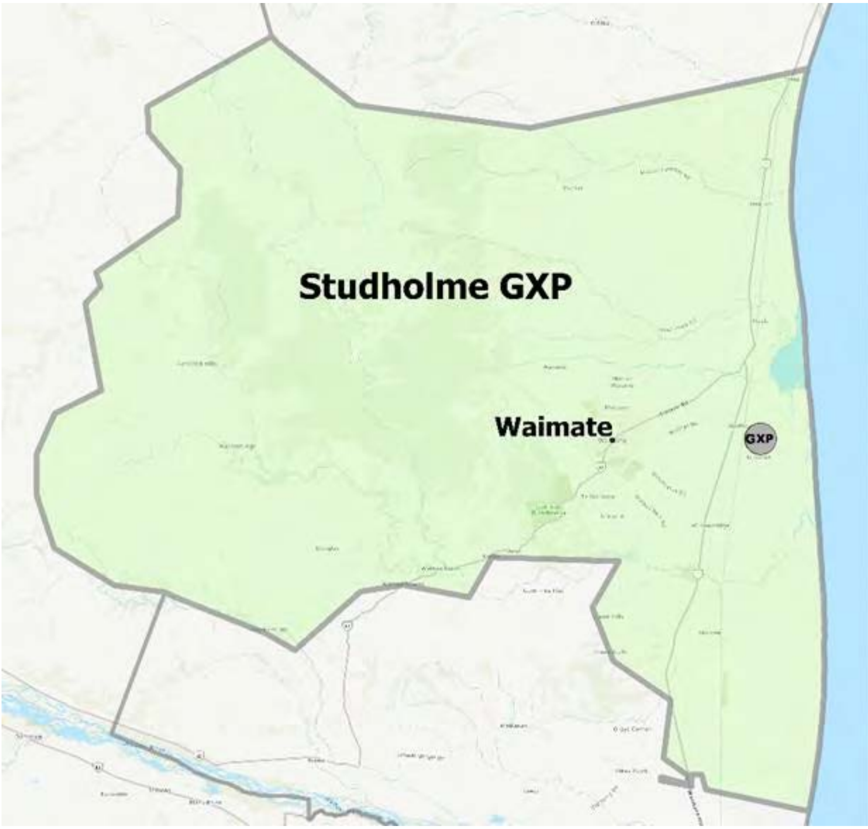
5.9.3 STUDHOLME (WAIMATE)

5.9.3.1 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, maintaining the population of the Waimate township.

ODL is also a substantial employer in the region and thus supports a stable population level for townships like Waimate. Fonterra operates their Studholme dairy factory, which is located close to the Studholme GXP.

Figure 5-16: Studholme GXP supply area



5.9.3.2 NETWORK CONFIGURATION

The Studholme network configuration is described in Appendix A.6.3.

5.9.3.3 DEMAND FORECAST

The load forecasts for the Studholme GXP, and the regional zone substation are shown in Figure 5-17 and Table 5-9 respectively with further details provided in Appendix A.5. The historical irrigation load growth is depicted in the higher, medium term forecast whereas the short-term historical load is reflected in the lower/flat short-term forecast which includes a couple of years with wet summer periods.

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

Demand growth because of EV uptake can easily be accommodated through to 2025 on the basis of existing capacity at the GXP and zone substation level. We anticipate an upgrade to the GXP capacity between 2025 and 2026. Due to the low population density of this area, and based on current levels of EV uptake, we do not foresee any capacity constraints in this region for the first half of the planning period.

Figure 5-17: Studholme GXP load forecast

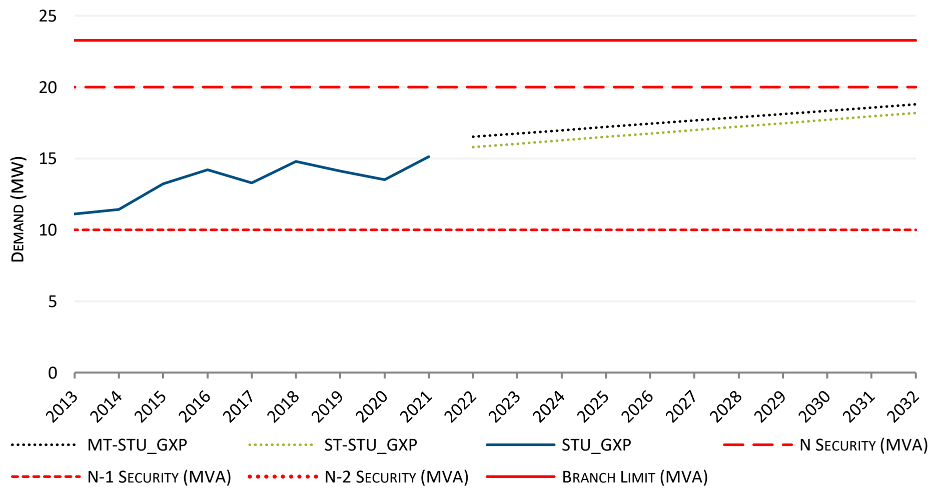


Table 5-9: Studholme zone substation load forecast in MW

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025
Studholme GXP	20.00	10.00	23.3	15.1	16.5	16.8	17.0

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

5.9.3.4 SECURITY OF SUPPLY

Table 5-10: Studholme security of supply

Zone sub / load centre	Actual	Target	Comment
STU_GXP	N	N-1	Security target is not currently met in accordance with our Security of Supply standard. Negotiations with Transpower is underway to replace/upgrade the two supply transformers.

5.9.3.5 EXISTING & FORECAST CONSTRAINTS

The existing load on the 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.

The Studholme GXP and zone substation can supply up to 1 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 which results in voltage constraints.

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.

Throughout this region, there is a challenge with keeping the voltage within the regulatory limits. This is evident by the number of voltage regulators deployed in the region already.

For any load at the Studholme dairy factory over 3 MVA will require network investment for dedicated feeders and 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[28] 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.

5.9.3.6 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	T+2 years after commitment to build new GXP

The combined STU and BPD available transmission capacity is 34 MW. It is expected that the load from these GXPs will reach this capacity around 2022/23. More capacity is available when the 110 kV transmission circuit is split at STU and STU is supplied from Timaru.

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 or Livingstone. This could free up 60 MW of capacity at STU and BPD for our network.

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)	Transpower investment project
Expected project timing	2025-2026

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.

[28] Each transformer can run at 11 MVA.

Increase security to the Waimate township and reconfigure existing feeders.

Estimated cost (concept)	$450 k
Expected project timing	2022/23

To improve the supply security to the Waimate township, we are splitting the township load across multiple feeders (as opposed to just one) to reduce the impact of a single contingency on the network supplying the township. This project will include the installation of several RMUs as well as additional overhead infrastructure to allow more network configuration options.

It is expected that future load growth on various 11 kV feeders, will require upgrades to these feeders.

The feeders that will be constrained are:

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

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

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 which will be available in 2026/27.

Fonterra Studholme dairy factory N-1 security upgrade

Estimated cost (concept)	TBC
Expected project timing	T+3 year on request from Fonterra

Like 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.[29]

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.

5.9.4 TEKAPO

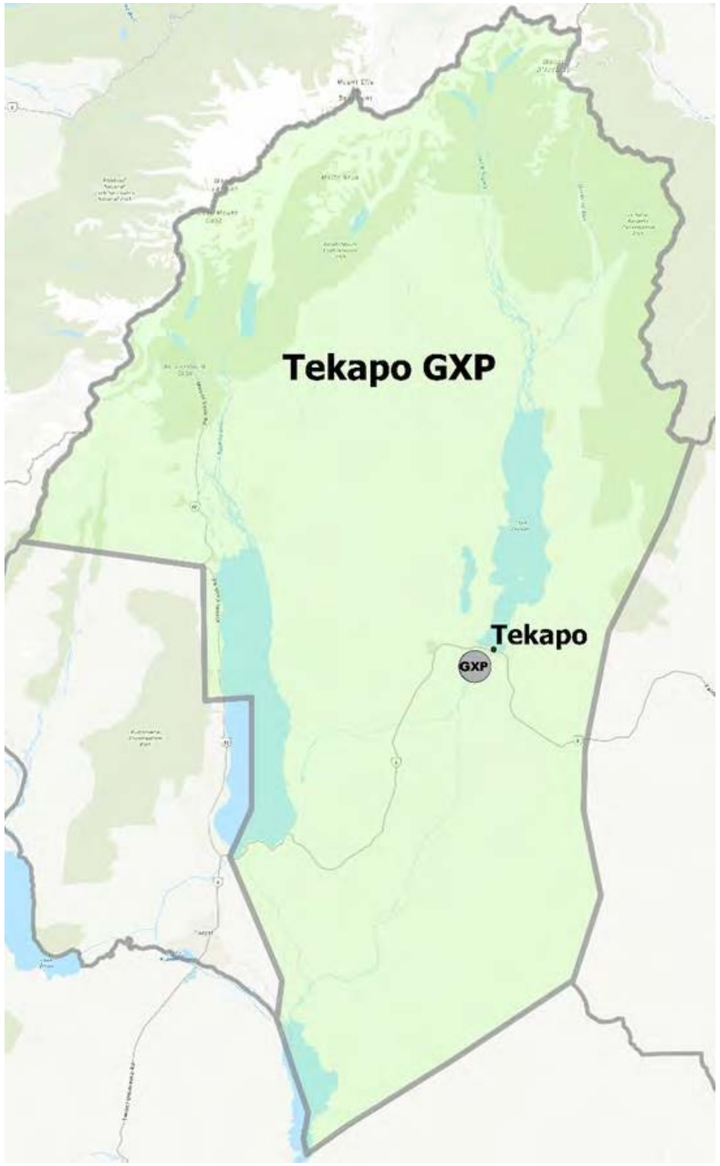
5.9.4.1 OVERVIEW

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 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 significant projected load growth in the Tekapo area, mainly new retail developments and subdivisions in the Tekapo township.

[29] Refer to System Security Forecast from Transpower.

Figure 5-18: Tekapo GXP supply area



5.9.4.2 NETWORK CONFIGURATION

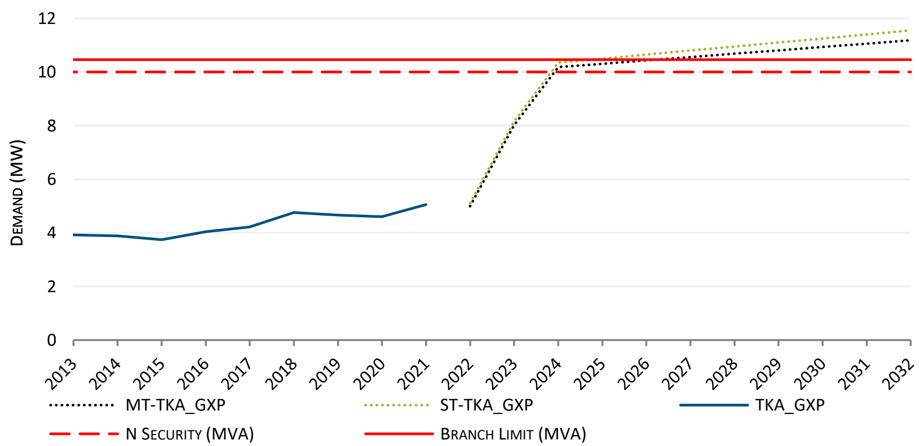
The Tekapo network configuration is described in Appendix A.6.4.

5.9.4.3 DEMAND FORECAST

Demand forecasts for the Tekapo GXP, and regional zone substations are shown in Figure 5-19 through Figure 5-22 respectively with additional details in Appendix A.5.

We have received a distributed generation (DG) initial application for 10 MW in the Tekapo area. No information of the likely timeframe for the construction is available but we have been approached by the generator regarding detailed design and system stability studies.

Figure 5-19: Tekapo GXP load forecast



There is significant growth underway in the form of subdivisions and commercial developments, such as hotels, in the Tekapo township. This forecast load growth is depicted in Figure 5-20 for the Tekapo zone substation and load growth at the GXP is depicted in Figure 5-19. This growth has triggered investigation into increasing GXP capacity, sub-transmission and zone substation's security of supply levels and capacity. We have upgraded the zone substation transformer capacity in 2021 to 15 MVA.

The forecast load growth in the rural regions is flat as depicted in Figure 5-21 and Figure 5-22 respectively.

Figure 5-20: Tekapo zone substation load forecast

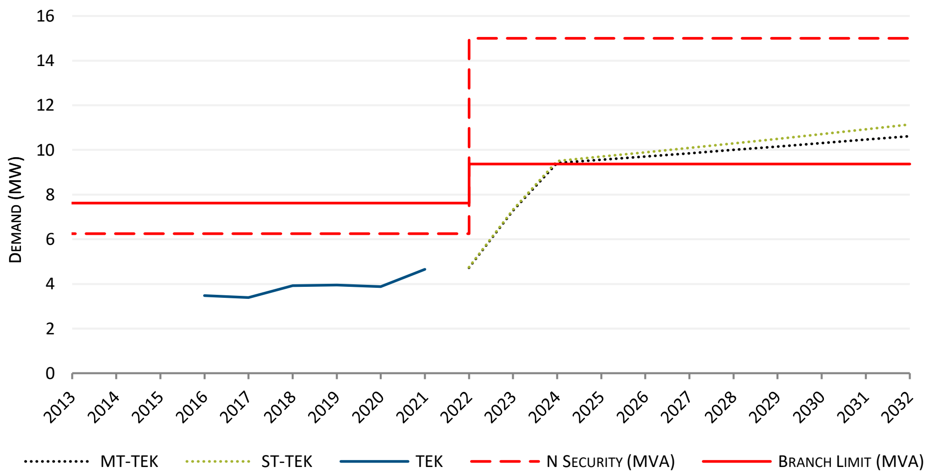


Figure 5-21: Haldon-Lilybank load forecast

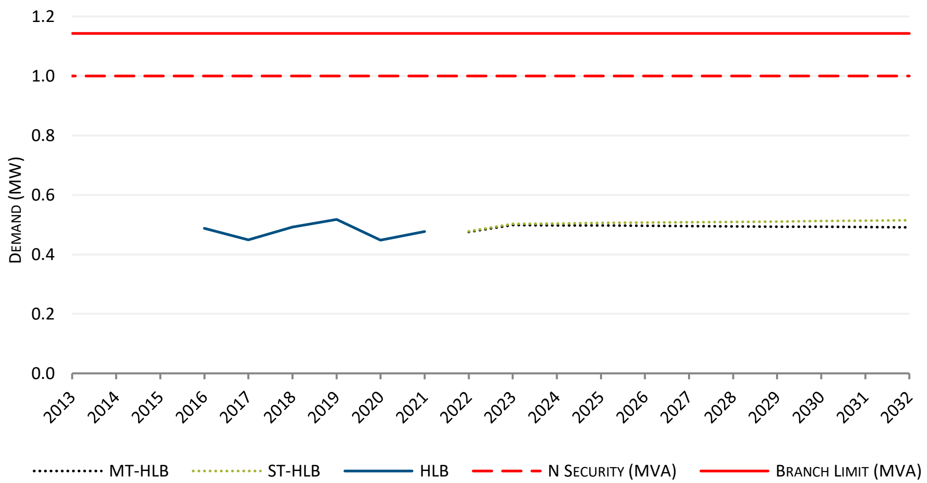


Figure 5-22: Unwin Hut load forecast

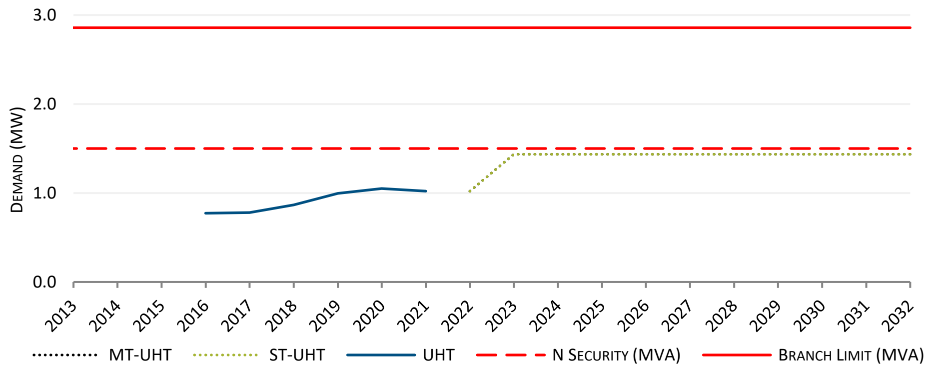


Table 5-11 Tekapo region load forecast in MW

Substation	N security (MVA)	Branch limit (MVA)	2022	2023	2024	2025
Tekapo GXP	10.00	10.46	5.0	8.0	10.2	10.3
Tekapo zone substation	6.25	7.62	4.7	7.3	9.4	9.6
Haldon-Lily Bank zone substation	1.00	1.14	0.5	0.5	0.5	0.5
Old Man Range zone substation	1.50	1.40	0.4	0.5	0.5	0.5
Unwin Hut zone substation	1.50	2.86	1.0	1.4	1.4	1.4

5.9.4.4 SECURITY OF SUPPLY

Table 5-12 Tekapo region security of supply

Zone sub/load center	Actual	Target	Comment
TKA GXP	N	N-1	The GXP's target is N-1 in accordance with our Security of Supply (SOS) standard due to its high growth rate and criticality being a populate tourism destination.

Zone sub/load center	Actual	Target	Comment
			TP has evaluated this GXP as of 'Low Economic Consequence'[30] and hence do not have a target of providing a higher security for it during this planning period. This is because a 28 MVA generator can provide black start support at 11 kV. We have entered discussions with TP to explore the feasibility of providing higher security at 33 kV supply level. Provision is made for this as part of the Transpower 11 kV switchboard replaced.
TKA-TEK 33 kV line	N	N-1	N-1 is the desired security level for this GXP up to the Tekapo zone substation (TEK), hence option will need to be assessed to increase the sub-transmission line security to provide that level of security.
TEK zone substation	N	N-1	N-1 is the desired security level for TEK. For this, the options are either to install a second transformer at the existing zone substation or a new zone substation at a different location by FY23/24. This will be in conjunction with increasing the existing TEK zone substation capacity.
HLB zone substation	N	N	Security target is met for this planning period in accordance with our SOS standard.
OMR zone substation	N	N	Security target is met for this planning period in accordance with our SOS standard.
UHT zone substation	N	N	Security target is met for this planning period in accordance with our SOS standard.

5.9.4.5 EXISTING & FORECAST CONSTRAINTS

There is significant development occurring in and around the Tekapo township. This includes subdivisions, an additional commercial central business district, and hotels. This growth has triggered a need to invest in increasing GXP, sub-transmission and zone substation's capacity.

The increasing demand also led to increased load on the feeders into the township. With no voltage control capability at the Haldon-Lilybank zone substations, network investment will be required when voltage constraints develop.

The existing ripple injection plant is a 500 Hz rotary plant[31]. The functionality of this plant will reduce our ability to consider demand side management as an option to defer network investments.

5.9.4.6 MATERIAL GROWTH AND SECURITY PROJECTS

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

TKA GXP step-up transformer upgrade

Estimated cost (concept)	TBC (Transpower Works Agreement)
Expected project timing	2023-2024

As per our load forecast, the 10 MVA capacity of the GXP will be reached by 2024 if all proposed load eventuates. We have approached Transpower to investigate the possibility of GXP capacity upgrade and whether improvement to the security is feasible given the growing tourism trade especially from overseas tourist that stays and pass through the township.

These discussions are done in conjunction with designs for the Transpower 11 kV switchboard replacement project.

TKA GXP – TEK zone substation 33 kV feeder upgrade

Estimated cost (concept)	TBC
Expected project timing	2027/28

As per our load forecast, the sub transmission line's 14 MVA capacity will be reached by 30/31. However, we will be exploring options to upgrade the line and possibly relocate it to make room for possible developments in the area. To meet our target of N-1 security for Tekapo, options will be assessed to reach that target as part of the GXP security improvement project.

Tekapo zone substation security of supply upgrade

Estimated cost (concept)	$3 M
Expected project timing	2023-2025

The transformer at the Tekapo zone substation has been upgraded in FY21/22. Now our security of supply standard will require N-1 security. This will require a second transformer to be installed at the existing zone substation, or at a new 'twin' zone substation at a different location.

Upgrade feeder(s) into the urban area of Tekapo

Estimated cost (concept)	$950 k
Expected project timing	2022/24

[30] Economic Consequence is the amount of load being served at a Points of Service (POS) multiplied by the VoLL at that POS, and is the expected dollar cost of an unplanned interruption at that POS

[31] A rotary ripple plant is a plant where the ripple signal is generated by an electrical motor type generator as opposed to a solid state (power electronic) signal generator.

The existing 11 kV feeders into the Tekapo township have become constrained in FY21/22. To increase capacity, a section of cable out of the substation will be upgraded. In addition, the two overhead lines will be replaced and upgraded with underground cables circuits. A third township feeder named Lakeside, was commissioned in FY21/22.

Substantial load growth within the Tekapo township requires extension to the backbone infrastructure which is made up of several underground cable circuit sections.

Ripple injection plant replacement

Estimated cost (concept)	$400 k
Expected project timing	2026
Replace 500 Hz rotating plant. Consider smart metering functionality.	

5.9.5 TEMUKA

5.9.5.1 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, continues to experience development in cropping and dairying with supporting irrigation.

The other larger urban area is Geraldine, a township with a population of 2,300. Geraldine benefits from the passing of tourists on the way to Tekapo and Queenstown.

5.9.5.2 NETWORK CONFIGURATION

The Temuka GXP and zone substation network configuration is described in Appendix A.6.5.

5.9.5.3 DEMAND FORECAST

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

We have received a distributed generation (DG) initial application for 26 MW in the Clandeboye area. No information of the likely timeframe for the construction is available but we are liaising with the generator on detail designs.

Figure 5-23: Temuka GXP supply area

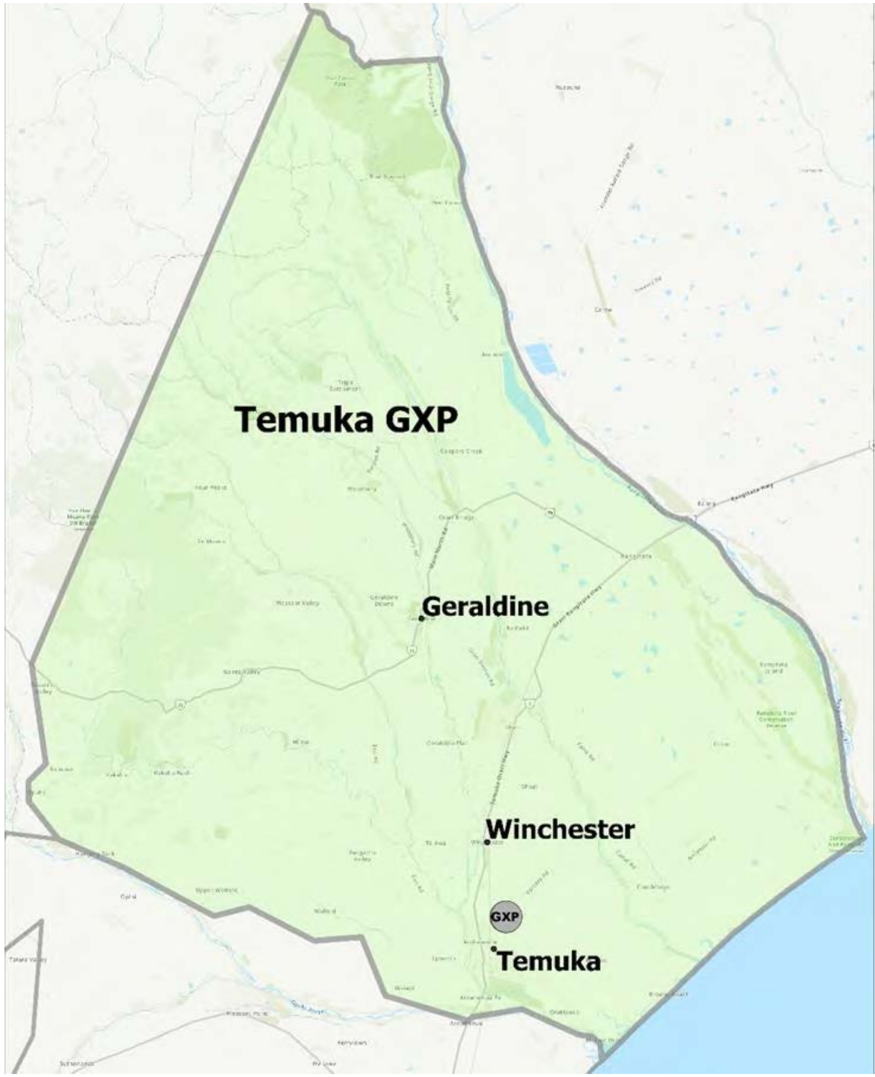


Figure 5-24: Temuka GXP load forecast

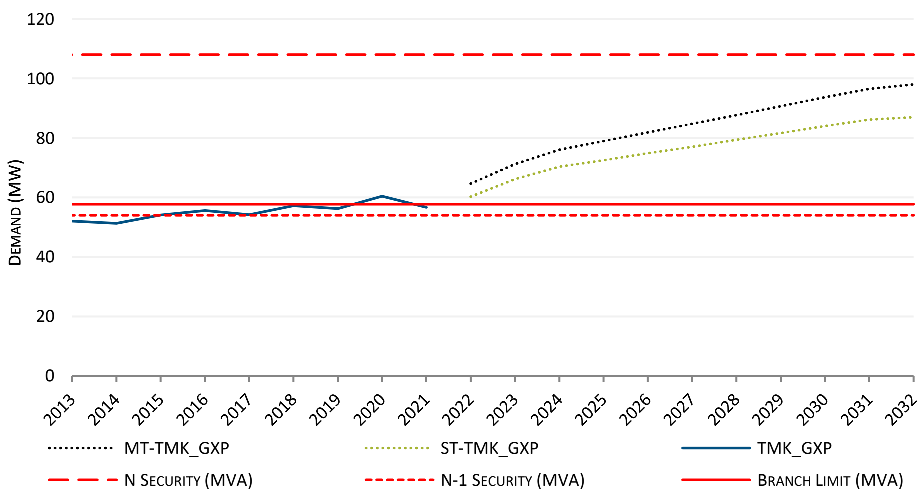


Figure 5-25: Temuka zone substation load forecast

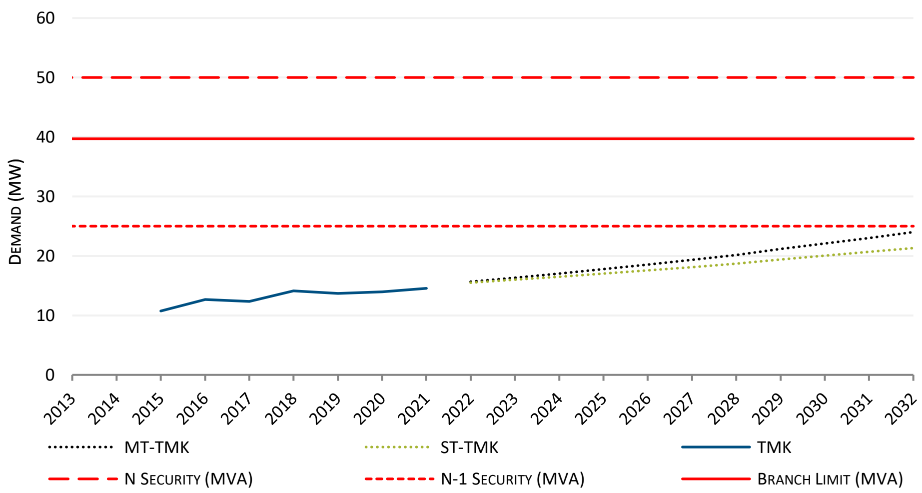


Figure 5-26: Geraldine zone substation load forecast

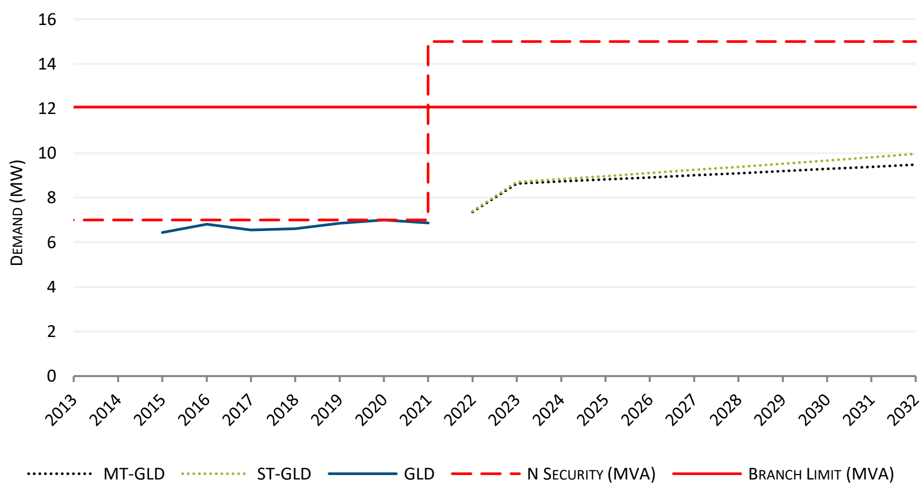


Figure 5-27: Clandeboye 1 zone substation load forecast

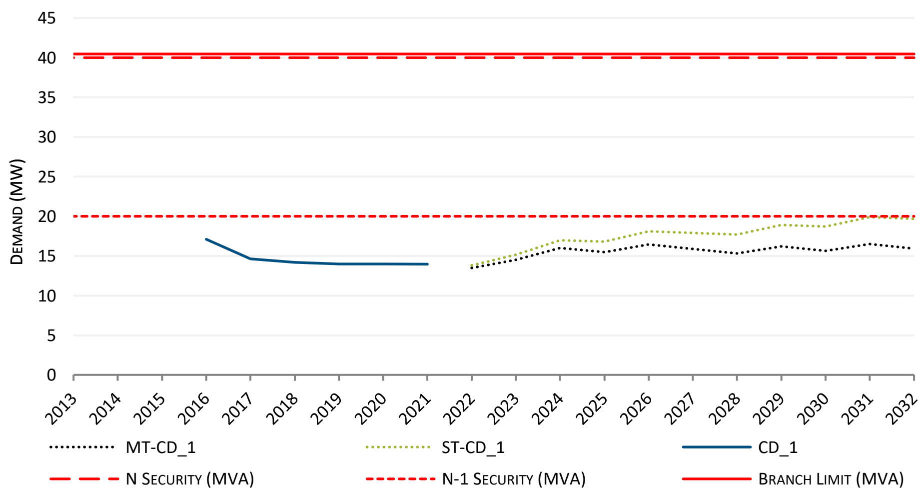


Figure 5-28: Clandeboye 2 zone substation load forecast

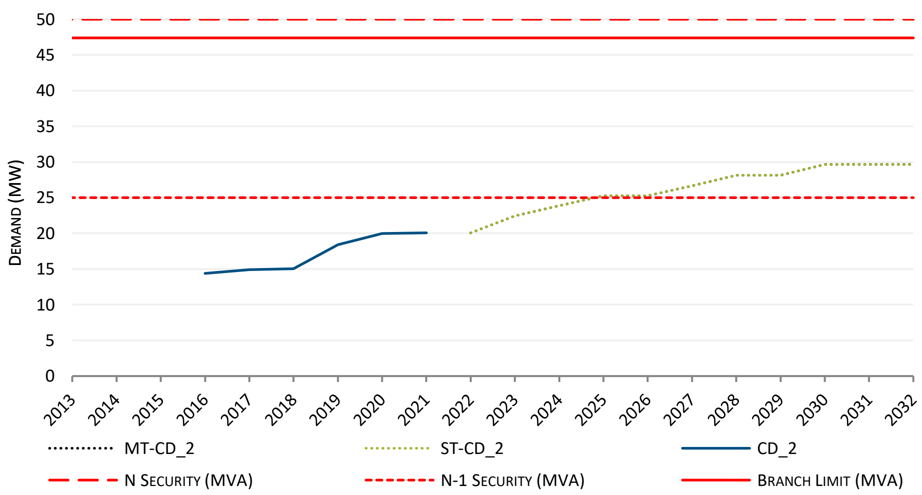


Figure 5-29: Rangitata 1 zone substation load forecast

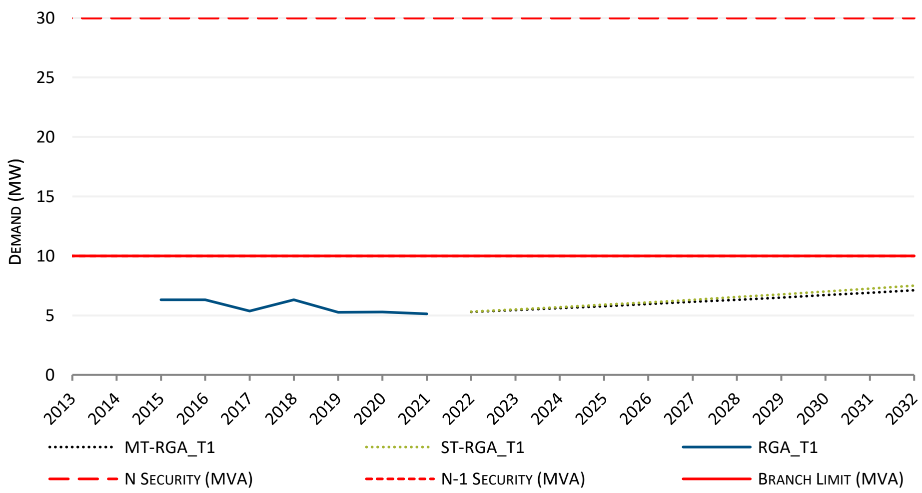


Figure 5-30: Rangitata 2 zone substation load forecast

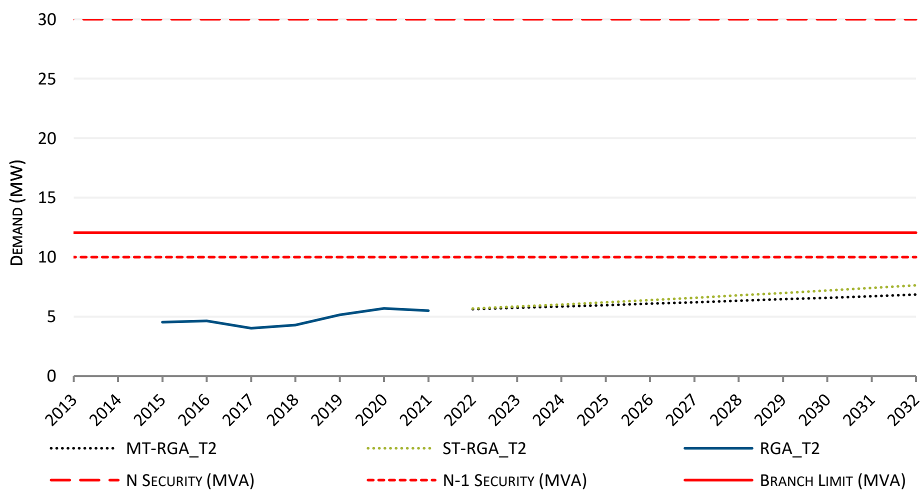


Table 5-13 Temuka region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025
Temuka GXP	108.00	54.00	93.36	68.5	72.6	77.5	80.4
Temuka zone substation	50.00	25.00	40.50	15.7	16.3	17.0	17.8
Geraldine zone substation	7.00	-	10.34	7.4	8.6	8.7	8.8
Rangitata zone substation	30.00	10.00	10.00	10.64	10.67	10.74	10.79
Clandeboye #1 zone substation	40.00	20.00	40.46	15.0	14.5	16.0	16.9
Clandeboye #2 zone substation	50.00	25.00	48.11	22.5	23.9	25.3	25.3

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 power at at N-1 security. Transpower has been commissioned for a concept design report to upgrade the Temuka GXP.

5.9.5.4 SECURITY OF SUPPLY

Table 5-14 Temuka, Geraldine, Rangitata and Clandeboye security of supply

Zone sub/load centre	Actual	Target	Comment
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 sub-transmission circuits and zone substations.	N-1	Load can be supplied by adjacent 11 kV feeders on the Fonterra dairy factory site. The N-1 SOS may be lost with the impact of decarbonization targets of Fonterra.
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 (through switching) 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.

5.9.5.5 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 sub-transmission 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, there is only N-1 security on the 33 kV sub-transmission 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 regarding 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[32].

5.9.5.6 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)	$15 M (stage 1)[33] $400 k[34]
Expected project timing	Possibly 2025

We have asked Transpower to commission a Concept Design Report (CDR) for the Temuka GXP upgrade. The CDR was received on 22 December 2017. A revised TWA costing was received from Transpower in 2021 after progress stalled due to commercial terms concerns.

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.

CD1 zone substation upgrade/replacement/relocation	
Estimated cost (concept)	$4.5 M
Expected project timing	T+3 years

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

[33] Transpower Works Agreement (TWA) costs.

[34] Alpine Energy costs for cable reconfiguration.

CD1, the oldest of the two zone substations supplying the Fonterra Clandeboye dairy factory, does not have N-1 security anymore. The existing substation has a limited footprint available, due to factory expansion encroaching on it.

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

The options are being discussed with the consumer and timing depends on Fonterra's objectives.

CD2 zone substation upgrade

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

CD2 zone substation will exceed the N-1 security level in 2024.

Upgrade options will be discussed with the consumer and timing depends on Fonterra's objectives.

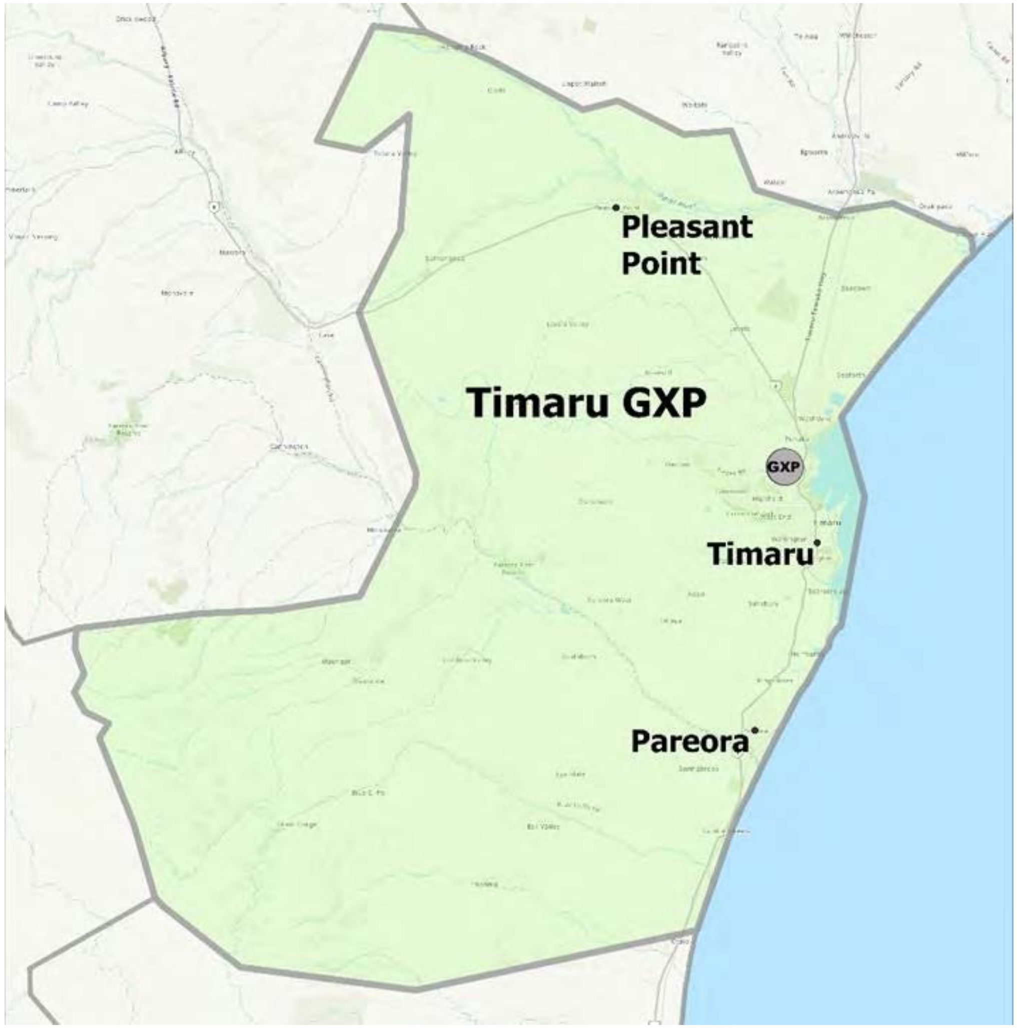
5.9.6 TIMARU

5.9.6.1 OVERVIEW

The majority of our 33,700 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. Most of the load growth in the city comes from industrial development in the Washdyke and port areas.

The port operations at PrimePort Timaru[35] continue to be an important part of the region's economy. Holcim cement 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.

Figure 5-31: Timaru GXP area



5.9.6.2 NETWORK CONFIGURATION

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

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

5.9.6.3 DEMAND FORECAST

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

We have received a distributed generation (DG) initial application for 6.5 MW in the Washdyke area. No information of the likely timeframe for the construction is available.

Figure 5-32: Timaru GXP load forecast

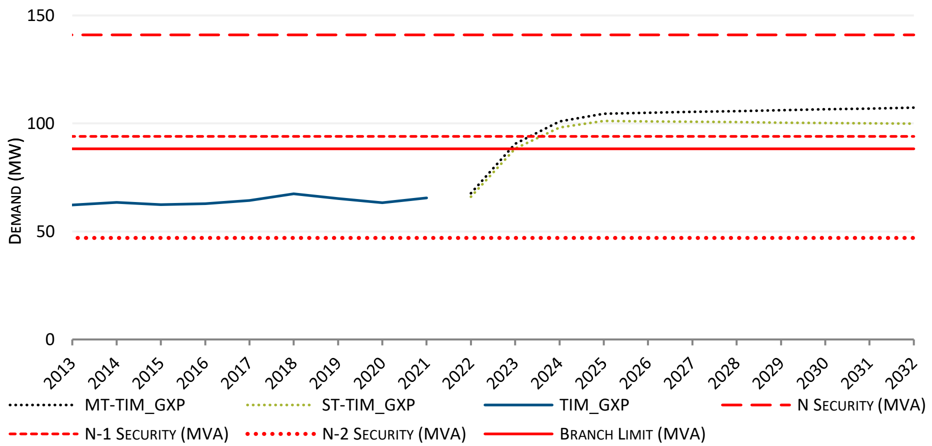


Figure 5-33: Timaru zone substation load forecast

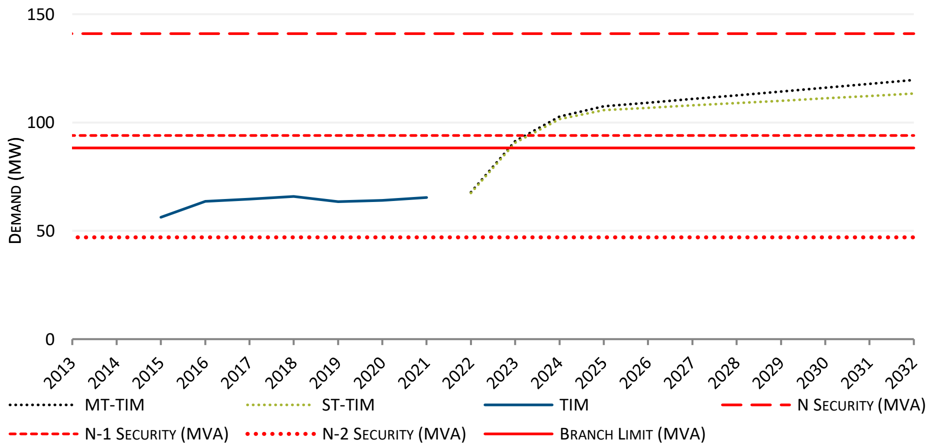


Figure 5-34: Timaru 11/33 kV zone substation T1 load forecast

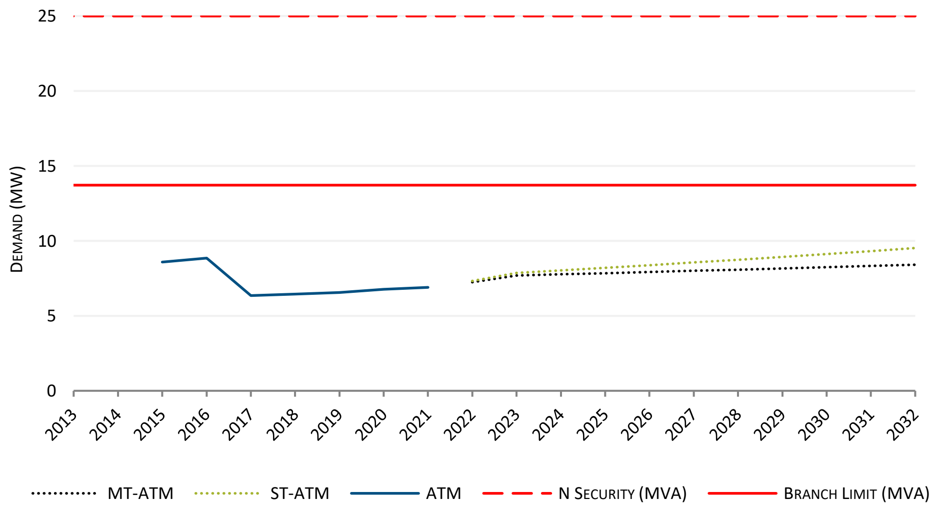


Figure 5-35: Timaru 11/33 kV zone substation T2 load forecast

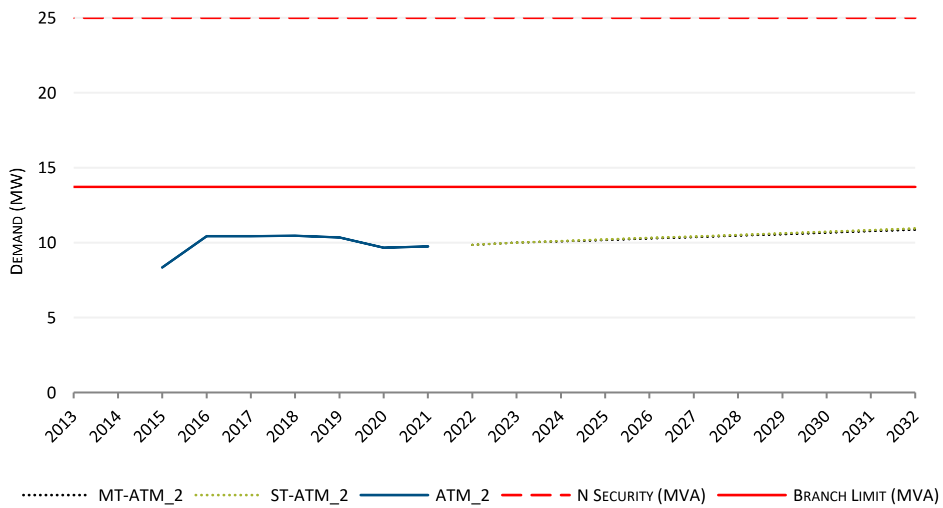


Figure 5-36: Pareora zone substation load forecast

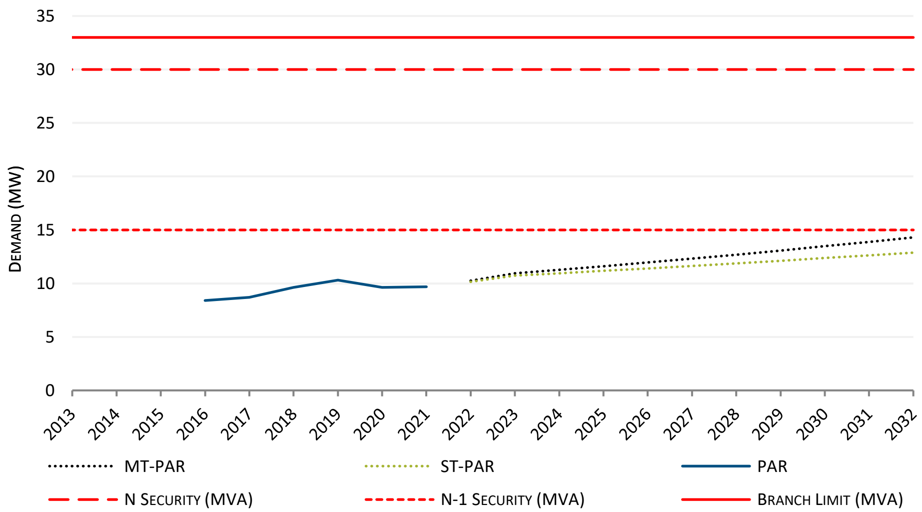


Figure 5-38: Grassmere switching station load forecast

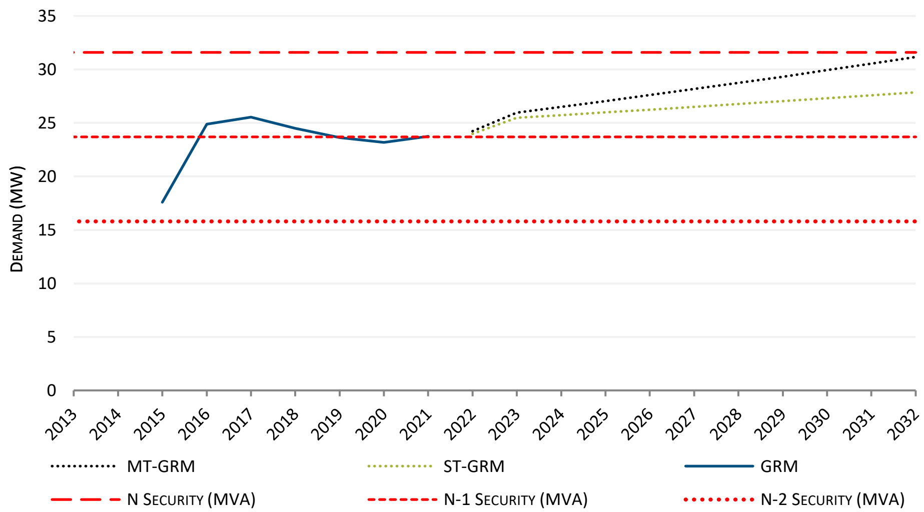


Figure 5-37: Pleasant Point zone substation load forecast

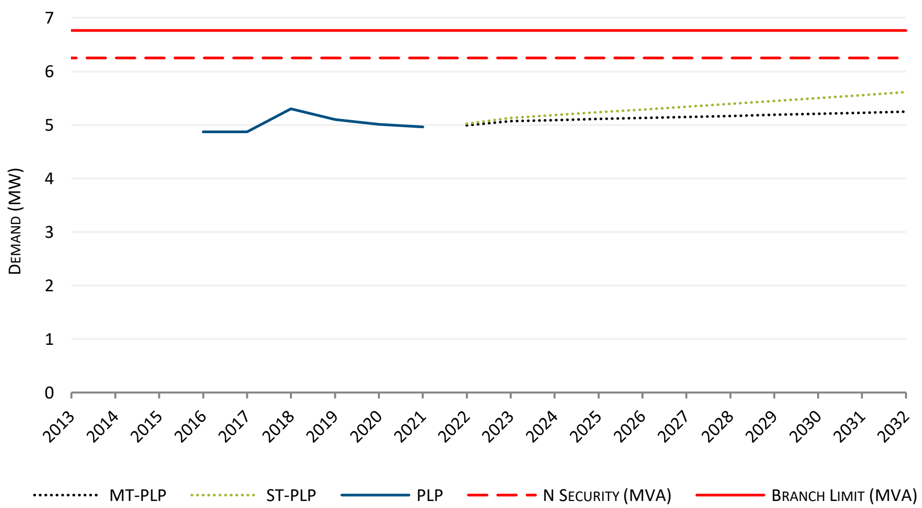


Figure 5-39: North Street switching station load forecast

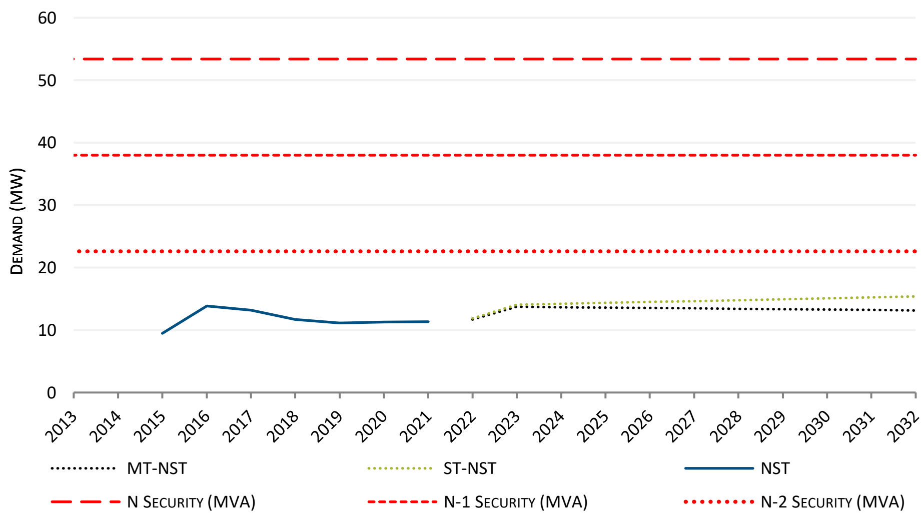


Figure 5-40: Hunt Street switching station load forecast

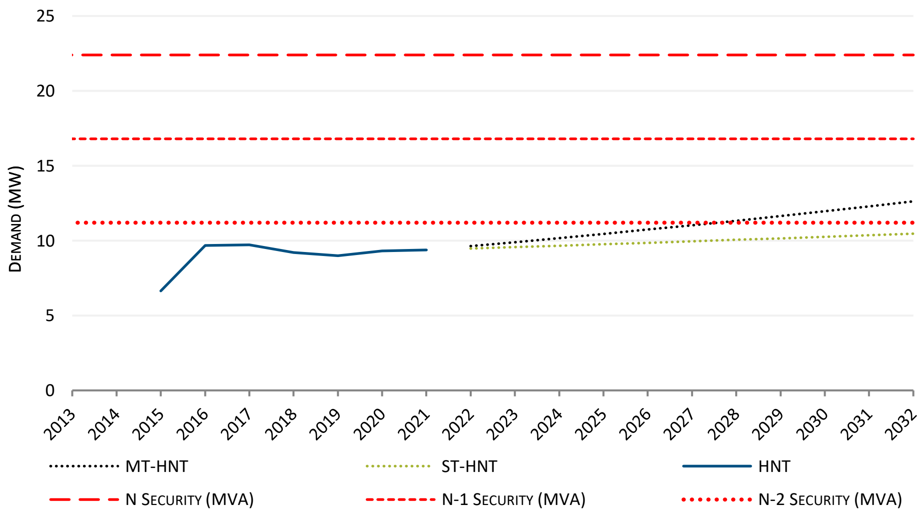


Figure 5-41: Wasdyke Switching Station load forecast

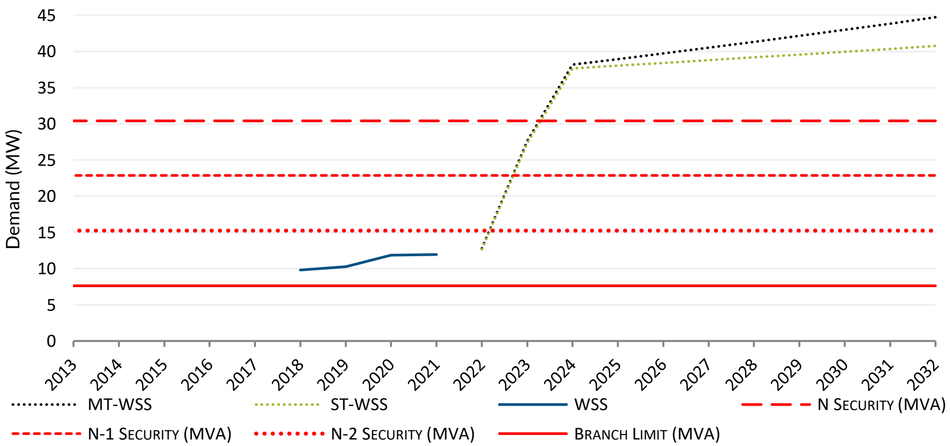


Table 5-15 Timaru region demand forecasts

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025
Timaru GXP	141.00	94.00	88.3	65.5	67.7	90.6	100.9
Timaru zone substation	141.00	94.00	88.3	65.4	67.8	91.3	102.7
Alpine Timaru Zone 33 kV Substation (T1)	25.00	-	13.7	6.9	7.2	7.7	7.8
Alpine Timaru Zone 33 kV Substation (T2)	25.00	-	13.7	9.7	9.8	10.0	10.1
Pleasant Point zone substation	6.25	-	6.8	5.0	5.0	5.1	5.1
Pareora zone substation	30.00	15.00	33.0	9.7	10.3	10.9	11.3
Grasmere switching substation	31.60	23.70	41.9	23.8	24.2	26.0	26.5
North Street switching substation	53.40	38.00	30.3	11.4	11.7	13.7	13.7
Hunt Street switching substation	22.40	16.80	30.3	9.4	9.6	9.9	10.2
Washdyke Switching Station	30.40	22.86	7.6	11.9	13.4	29.1	41.3

There are significant step changes in load mainly in Washdyke area along with the residential subdivisions that are taking place in the western area and port demand increases on the southern side of the port.

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 lodged a submission to 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 the growth management strategy consultation.

With the government's decarbonisation drive on its second round there has been significant load changes which are driving up the demand forecast for the planning period and bringing forward potentially significant network upgrades to meet the demand. Overall, this drives up demand across the Timaru GXP region, mostly in the industrial area of Washdyke.

5.9.6.4 SECURITY OF SUPPLY

The security of supply for Timaru, Pareora and Pleasant Point zone substations are detailed in Table 5-16.

Table 5-16 Timaru, Pareora, and Pleasant Point security of supply

Zone sub/load centre	Actual	Target	Comment
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	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	N-1 (switched)	Four new 33 kV cable circuits from Seadown to Timaru to run at 11 kV were installed in 2017.The lack of a switchboard with a full bus at the Washdyke switching station limits the Security of supply.
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.
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.
Pleasant Point 33/11 kV zone substation	N	N	Some load can be supplied using 11 kV feeders from Pleasant Point t, Temuka and Timaru zone substations in an emergency.

5.9.6.5 EXISTING & FORECAST CONSTRAINTS

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 comprise 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 sub-transmission 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).

In the Western area of Timaru there are 11 kV distribution feeders that are run through the back of residential sections. Access to these assets is problematic. Projects are underway to replace these feeders with underground cables on public roads.

5.9.6.6 MATERIAL GROWTH AND SECURITY PROJECTS

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

WSS zone substation	
Estimated cost (concept)	$4-7 M[36]

[36] Cost is dependant on the requirements of the land use consent.

Expected project timing	TBC[37]

Load at the Washdyke site is expected to be between 40 and 45 MVA in the ten-year planning period and the existing ring main configuration does not allow for ease of backup. Capacity between feeders is stranded at this critical network point due to the limited switching ability.

Proposed solutions:

- Construct switch room and install 11 kV switchboard.
- Construct switch room and install 33 kV switchboard (bus the 33 kV).
- Install 33/11 kV power transformer(s).

The combination of all of the above would result in a new zone substation. We are in the fortunate position that four cable circuits from the GXP to this site is rated at 33 kV and currently operating at 11 kV.

This zone substation is required to supply any additional load as a result of decarbonisation as well as generis load growth as the Washdyke industrial area expands.

TIM GXP upgrade

Estimated cost (concept)	TBC[38]
Expected project timing	TBC[39]

The branch capacity and security of supply is expected to be exceeded by FY22/23 and FY23/24 respectively.

Proposed solutions:
Put third transformer into service to temporarily relieve the constraint.
Upgrade the GXP to 220/33 kV substation.

Timaru 33 kV Zone Substation (ATM) switchgear replacement

Estimated cost (concept)	$4.25 M
Expected project timing	2026/2028

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 is to be upgraded to a zone substation.

With decarbonisation loads increasing, this substation will limit us supplying the increased load at N and N-1 security.

[37] Timeframe dependant on the TIM GXP upgrade to 33 kV supply.

[38] The bulk of the cost will be covered under a TWA while there may be some costs related to our assets depending on the final solution.

The feasibility of this project will be considered in conjunction with the TIM GXP to a 33 kV or higher voltage as described in the previous project. If the GXP is upgraded to a 33 kV GXP, this project will form part of the GXP upgrade.

Pleasant Point transformer replacement

Estimated cost (concept)	$2.2 M
Expected project timing	2030

The existing transformer is forecast to reach its capacity in 2031 and will require upgrading or an alternative non-network solution.

Supply to Wool Works

Estimated cost (concept)	$2.1 M
Expected project timing	2022/23

With the decarbonisation at Wool Works in Washdyke, a 9 MVA supply from the Washdyke switching station is required.

The preferred solution is to install a double circuit underground cable to supply this load and to increase capacity to allow future development in Washdyke.

Supply to showgrounds

Estimated cost (concept)	$2.1 M
Expected project timing	2022/23

A large commercial development was started in 2021 at the old showgrounds complex which will house several large retail vendors.

The supply for this development will come from our Timaru GXP and will comprise two underground cable circuits and several distribution substations for which the exact locations are yet be specified by the developer.

5.9.7 TWIZEL

5.9.7.1 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, aquaculture, pet food manufacturing and processing, general engineering works, and providing permanent accommodation for substantial numbers of Meridian Energy and Department of Conservation staff, as well as staff working in the aquaculture industry.

[39] We are currently working with Transpower on a short list of options for the upgrade. Once finalised more certainty on the expected timeframe will be known.

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

5.9.7.2 NETWORK CONFIGURATION

The Twizel network configuration is described in Appendix A.6.7.

5.9.7.3 DEMAND FORECAST

Demand forecasts for the Twizel GXP, and regional zone substations are shown in Figure 5-43 and Figure 5-44 with further details provided in Appendix A.5.

There are no major step change load growth projects that we are aware of.

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 preferred) for the proposed increased Simons Pass load.

We have received a distributed generation (DG) initial application for 30 MW in the Twizel area. No information of the likely timeframe for the construction is available.

Figure 5-42: Twizel supply area

Figure 5-43: Twizel GXP load forecast

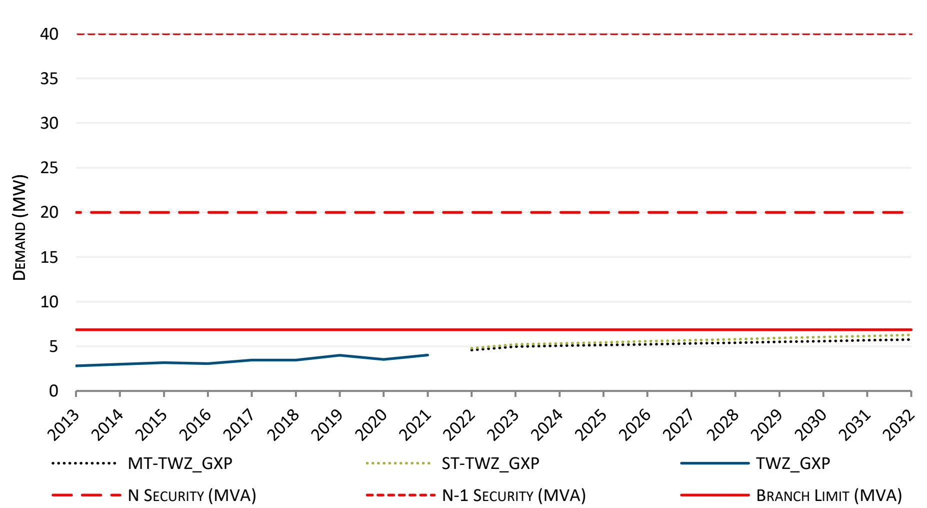


Figure 5-44: Twizel Village zone substation load forecast

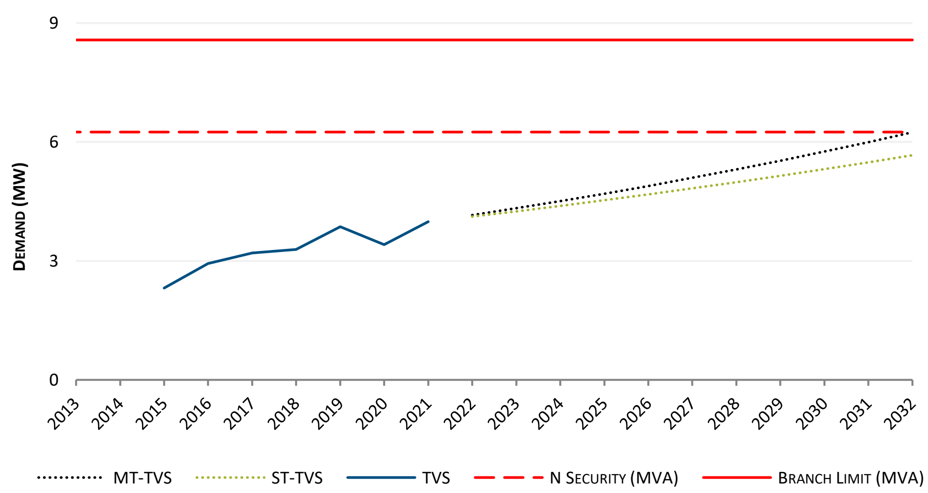


Table 5-17 Twizel region demand forecast

Substation	N security (MVA)	N-1 security (MVA)	Lowest rated equipment (MVA)	2022	2023	2024	2025
Twizel GXP	20.00	40.00 (Switched)	6.86	4.02	4.36	4.75	4.84
Twizel Village zone substation	6.25	-	8.57	3.99	4.16	4.33	4.51

5.9.7.4 SECURITY OF SUPPLY

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

Table 5-18 Twizel security of supply

Zone sub/load center	Actual	Target	Comment
Twizel residential	N	N-1	There is a 3 MVA spare 33/11 kV transformer (cold standby) located at TVS zone substation. As the substation is near its end of life, the security of supply at the power transformer level will be improved to N-1 at the same time as the replacement project.
Twizel rural	N	N	None.

5.9.7.5 EXISTING & FORECAST CONSTRAINTS

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

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

Our supply is not as secure as a tied bus arrangement, but this has been of little concern as the outage rate is very low. If a supply transformer is lost or released, Transpower can easily tie the two bus halves to the remaining transformer.

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

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

5.9.7.6 MATERIAL GROWTH AND SECURITY PROJECTS

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

Twizel Village zone substation (TVS) asset replacements	
Estimated cost (concept)	$2.6 M
Expected project timing	2022-2023
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 Village zone substation work.	

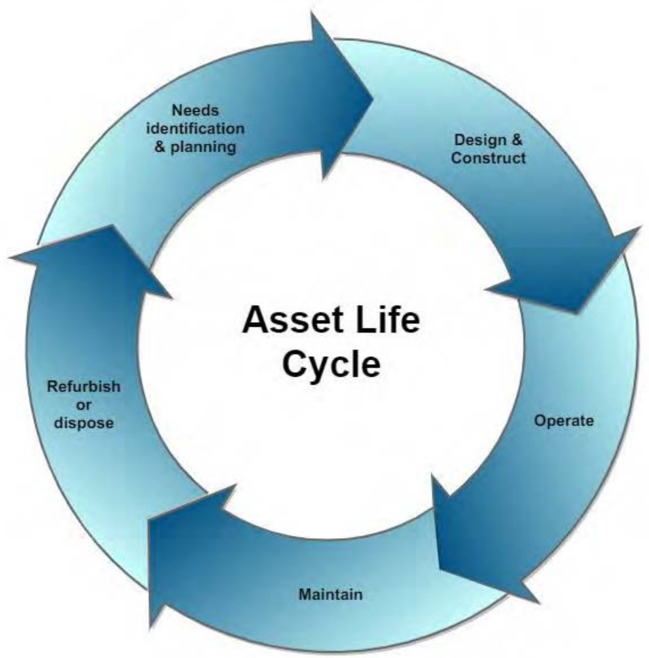
Transpower outdoor to indoor conversion of the GXP 33KV switchgear	
Estimated cost (concept)	TBC
Expected project timing	2022-2023
There is an opportunity to request an additional 33 kV circuit breaker as part of the Transpower project. This additional circuit breaker can provide N-1 supply to the TVS or supply a new 33/11 kV zone substation. This option will be considered together with the TVS replacement options.	

6 / Fleet Management

6. FLEET MANAGEMENT

This chapter explains our approach to the life cycle management of our asset fleet. Here we provide 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,
- Design and Construct,
- Operating,
- Maintaining, and
- Refurbishment (rehabilitating or modifying) or Disposal

To support our five asset management lifecycle strategies, we use asset fleets, which form our day-to-day asset intervention strategies. We continue to develop a comprehensive set of asset fleet strategies to set out our approach in 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 their life.

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, seven 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 sections of the network available for maintenance or repairs by contractors. In addition, they also manage the controllable load on our network to comply with retailer contracts with consumers and 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 the power supply. This team also works closely with the rural fire service in South-Canterbury by disabling auto-reclose functions on our pole mounted reclosers when conditions are dry and the fire risk is high.

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

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

The SCADA system 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.

We are currently undergoing a transformation journey to enable SCADA integration with other internal tools (e.g. GIS). Once implemented, we expect significant improvement in our fault responsiveness.

6.1.1.4 RELEASE PLANNING

Release planning is another task that the Control Centre manages daily. 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 allow us 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.
- Expanding the use of additional SCADA features, which include electronic switching preparation, field mobility, automatic load restoration etc, to name a few.
- Integration of SCADA with GIS and other ERP/CRM platforms.
- 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 SIE (System Interruption and Emergencies) activities 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 resources 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 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 meet contractual response times consistently.

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

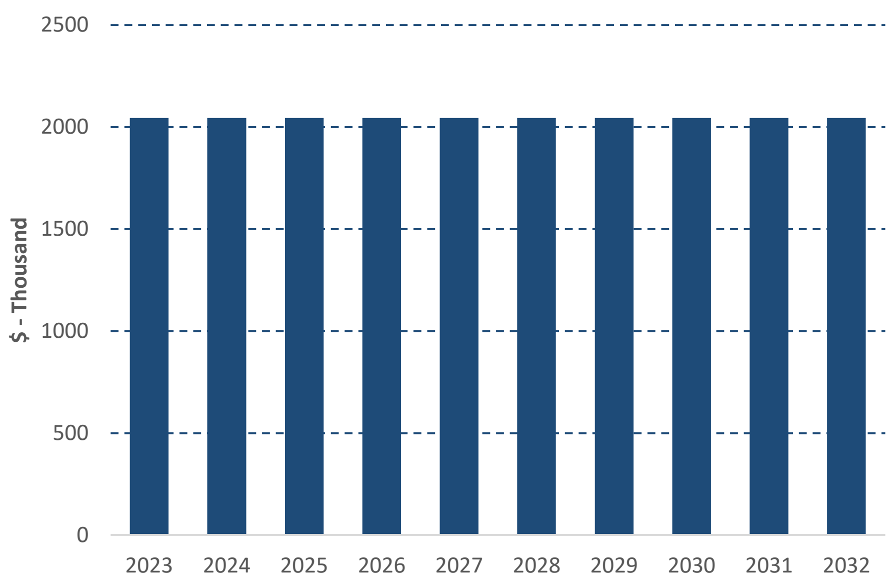
Asset management objective	Portfolio objective
Safety & environment	Reduce fault response time to reduce the potential risk of public safety. Reduce safety hazards by prioritising safety-driven faults.
Service levels	Minimise outage events and durations to support our regulatory reliability objectives.
Cost	Consider the use of alternative technology to reduce the 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 –** carry out field safety audits to ensure a consistent 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 tools 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 standby and within an 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 ten 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 the 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.
- Making use of drones fitted with cameras for asset inspections as part of our planned and unplanned work.

6.1.3 MAINTENANCE STRATEGY

Maintenance is the care of assets to ensure that they will provide their required capability safely and reliably from commissioning through to 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 asset's condition. 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, considering 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 and inspections,
- maintenance projects to replace components of assets, and
- vegetation maintenance.[40]

[40] Refer to section 6.1.5 for more detail.

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 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.

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 because 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 the condition-based inspection and monitoring programmes. This includes activities to replace components or repair assets 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 predict the likelihood of failure.

Proactive

Proactive maintenance is improvement work initiated because 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 projects 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, 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 many individual activities ensures the works programme is optimised and delivered more efficiently.

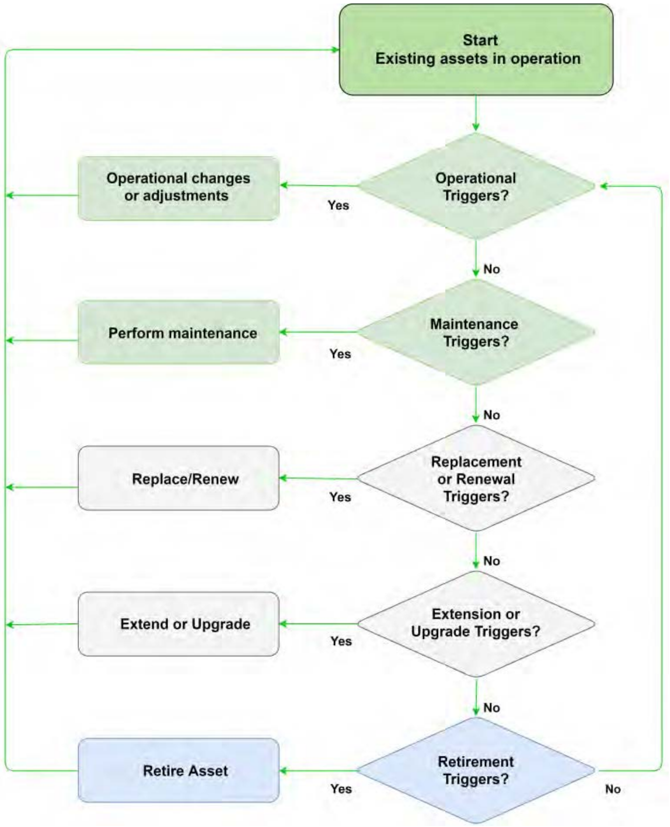
6.1.4 MAINTENANCE ACTIVITIES

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 ensures our maintenance approach considers 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 asset owner task),
- Maintenance Delivery is the planning and execution of the work (generally a contractor/service provider 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 because 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 the EAM system to better schedule tasks in the same areas and on the 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 are highly effective in reducing these outages.

6.1.5.1 KEY ACTIVITIES

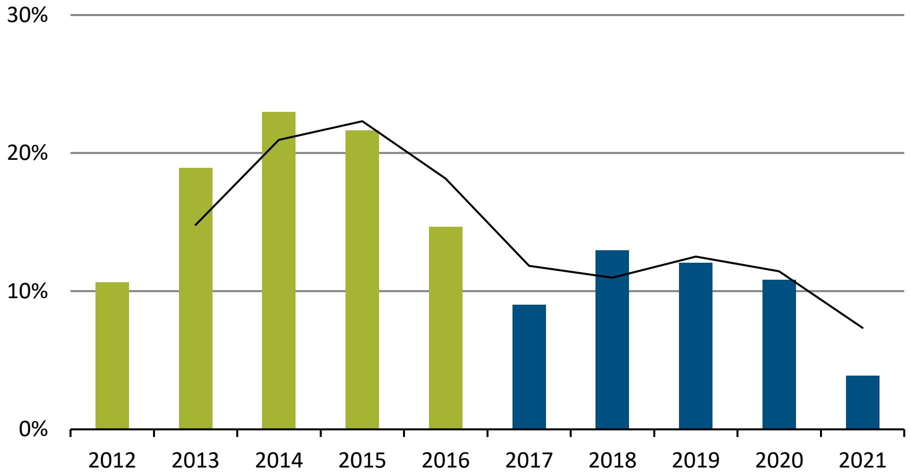
The main activities undertaken in the vegetation management portfolio are:

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

6.1.5.2 STRATEGIES AND OBJECTIVES

Vegetation management has a significant impact on network reliability and public safety. Prior to 2016, our network performance was adversely affected by an increasing number of interruptions caused by vegetation, as depicted in Figure 6-4.

Figure 6-4: Percentage of vegetation related interruptions



Since 2016 we have emphasised 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. The results are shown in Figure 6-4 where the actual data is displayed as well as a 2-year moving average trend line.

To guide our strategy and activities during the planning period, we have identified some high-level objectives for our vegetation management activities.

Table 6-3 Vegetation management portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	Reduce the potential risk of incidents affecting tree owners undertaking trimming work to improve public safety. Have a risk-based approach by prioritising higher risk trees.
Service levels	Ensure vegetation maintenance is undertaken by competent and network approved contractors and meets all H&S requirements.
Cost	Remain within budget and ensure a decline in operating costs by ensuring the appropriate parties take 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 Health & Safety and industry regulation compliance such as the various codes of practice and SM-EI, to name only two.
- 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 the 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 and mapping systems and to apply growth rates to assist 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.

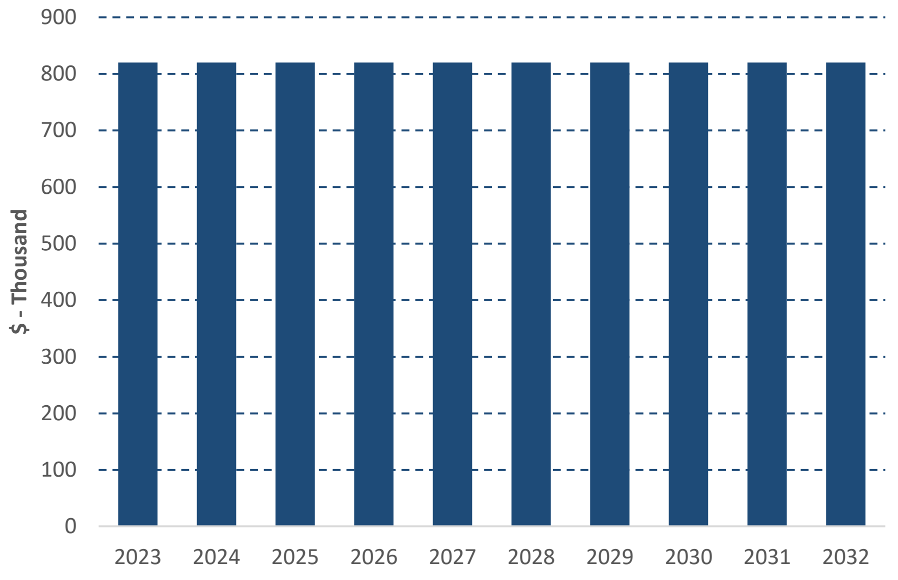
We actively manage the relationships with tree owners to ensure that the relevant parties meet their financial responsibilities.

6.1.5.4 VEGETATION MANAGEMENT OPEX FORECAST

Our vegetation management expenditure forecast for the planning period is shown in Figure 6-5.

In 2016 we recognised that our risk profile in relation to tree encroachment near our lines was high. This led to an increase in vegetation management OPEX to reduce this risk.

Figure 6-5: Vegetation management OPEX



The increase in regulation from Waka Kotahi with respect to traffic management to improve worker safety where work is undertaken along public roads has resulted in a higher forecast expenditure in vegetation management. The *Electricity Hazards from Trees Regulations 2003* was amended in 2021, clarifying the notification and application processes to works owners – directly changing the way our communities communicate with us regarding vegetation maintenance.

6.1.6 ASSET HEALTH INDICES

Asset health reflects the expected remaining life of an asset and acts as a proxy for the likelihood of failure. We have used asset health to inform our asset management approach for several our asset fleets. Using AHI (Asset Health Indices) we can estimate the required future volume of asset renewals and forecast the health outcomes of our investment scenarios. In all cases, except for wooden poles, we employ AHI by following the Electricity Engineers' Association's (EEA) *Asset Health Indicator Guide: 2016*.

The AHI categories are defined as detailed in Table 6-4.

Table 6-4 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 6-6. Detailed AHI data for most asset types is given in Chapter 6. Our AHI in this AMP is in accordance with the age-based methodology of the EEA's *Asset Health Indicator Guide 2016.* Where appropriate, the actual condition of an asset fleet is discussed rather than the age-based result.

Figure 6-6: Example of asset health profile

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 is presented, including population, age[41] and condition. Forecast expenditure for replacements and renewal for the planning period is also detailed. The portfolio includes the following asset fleets:

- Hardwood poles,

[41] Asset age data is given as at 31 March 2021. New assets installed or planned for the current financial year is specified in the text of each asset type section.

- Softwood poles,
- Mass reinforced concrete poles, and
- Pre-stressed concrete poles

Portfolio summary

Investment in overhead structures and conductors for the planning period is forecast at $64 M over the planning period. This portfolio accounts for 48% of the renewal 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 the 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. Currently, steel poles would only be used for special projects with unique strength-to-weight requirements.

Figure 6-7: Wood pole left and concrete pole right

6.2.2 PORTFOLIO OBJECTIVES

Table 6-5 Overhead structures portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	Safety in Design is considered for all structures. Replace structures using condition information before failure. Responsible disposal of obsolete poles and components. Ensure hardwood cross-arms are sourced from sustainable forests.
Service levels	Continual refinement of condition-based renewal techniques to improve feeder reliability (SAIDI & SAIFI) and end of life predictions.
Cost	Provide cost-effective designs, construction, operational and disposal techniques for all structures and lines.
Community	Minimise planned outages to consumers by coordinating replacement with other works. Minimise landowner disruption when undertaking renewal work.

Asset management objective	Portfolio objective
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 6-6. Most 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 6-6 Number and estimated life of pole types

Type	Number	% of total	Estimated life (years)	Average age
Hardwood	14,282	32%	40-60	38
Softwood	5,647	13%	25-50	33
Concrete mass reinforced	22,682	50%	60-100	42
Concrete pre-stressed	2,346	5%	60-100	7
TOTAL	**44957**	**100%**		

The majority of the 11 kV and 22 kV distribution network was built 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. Our wood pole age profile is shown in Figure 6-8.

Most concrete poles are more than 35 years old, with an average life of 41 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.

Figure 6-8: Wood pole age profile in years.

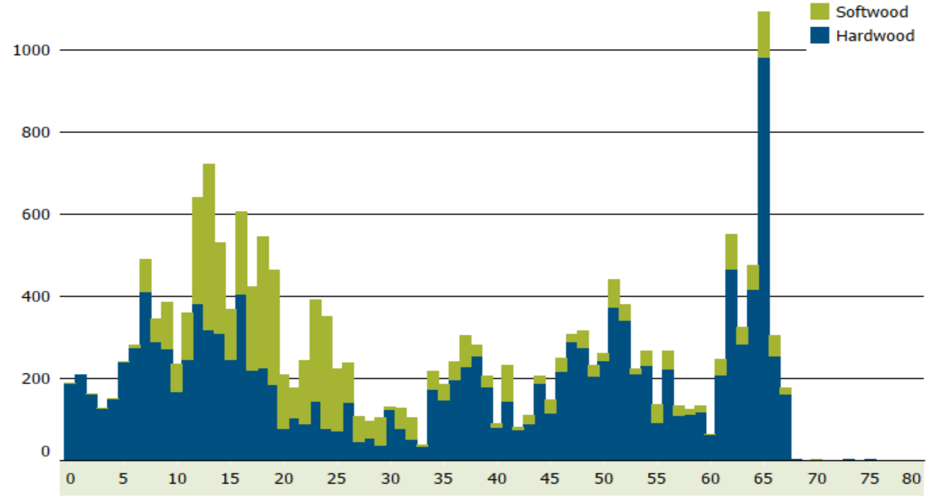
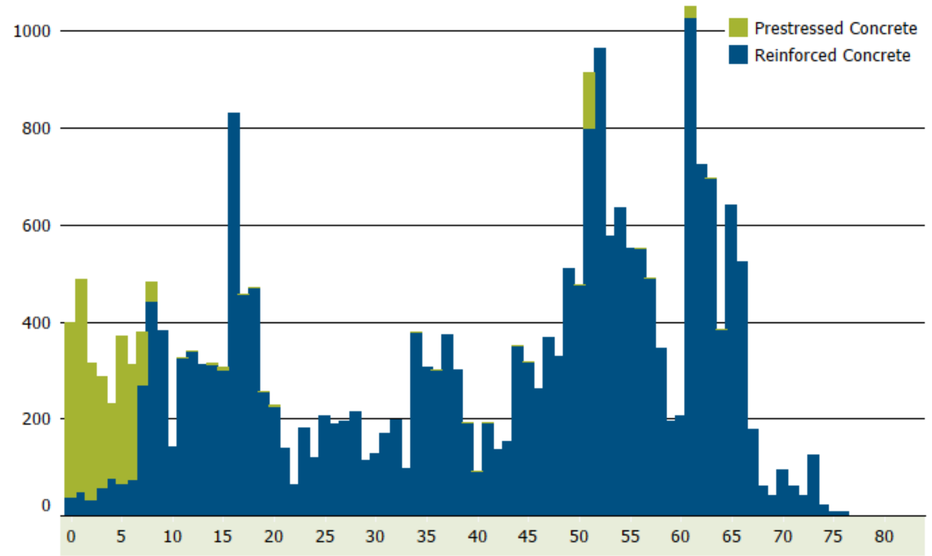


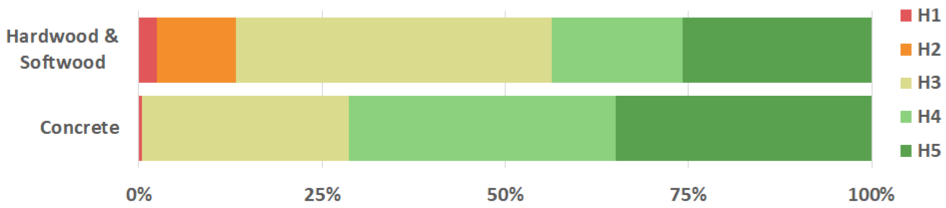
Figure 6-9: Concrete pole age profile in years



6.2.4 CONDITION, PERFORMANCE AND RISKS

We have developed AHI for wooden poles that reflect the probability of failure for these poles. H5 (as new) and H4 (normal deterioration) AHIs are calculated using the age of the pole in the manner that the EEA's *Asset Health Indicator Guide, 2016* propose. The past year's inspection records for wooden poles were then used to calculate the H2 (material failure risk) and H1 (end-of-life) AHI statistics. The proportion of yellow tagged poles identified during the past year was used to calculate the H2 AHI indictor; and the proportion of red-tagged poles was used to calculate the H1 AHI indictor. The actual asset condition and historical data available was used to adjust the EEA guide numbers. The asset health profile for our pole fleet is shown in Figure 6-10.

Figure 6-10: Pole structure asset health as at 2021.



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 have 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 - 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 principles of engineering practice and that continues today through a combination of "in-house" design spreadsheets, standards, and proprietary software, *CATAN*. The software we use, and our standards complies with the requirements of *AS/NZS 7000:2016 Overhead Line Design* and its related standards. The principles of safety in design were introduced in 2016.

Existing overhead infrastructure will only be undergrounded if:

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

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

Most of all overhead line design is done in-house, while a small portion has been contracted to consultants that are familiar with our standards. We have design standards and construction methods which are managed through our drawings management system Adept. Version control and transmittal of drawings, standards, and specifications are two of the main strengths of the system.

Most of our large overhead line projects are tendered in the market. Smaller projects are issued to our subsidiary contractor on an industry-aligned rate card system.

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 a low probability of 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 on a rolling ten-year basis, starting on its 25th anniversary. This means we inspect 10% of our total overhead line infrastructure that are 25 years or older.
- The condition assessment data is reviewed, analysed and a replacement program implemented.
- Cross-arm, insulator and other pole-top equipment 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 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 on top of a hot stick is used to scrutinise pole top component condition. We also use drones to conduct pole top inspections.

Our cyclic 10-year condition-based renewal process ensures a level of confidence in the condition of the oldest remaining poles. It effectively staggers the capital required for end-of-life replacement. The aim of the 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 specified in the *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 indicates that a pole may not be capable of supporting ultimate design loads beyond the next ten 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.

To remove human subjectivity, new technology for wood pole assessment is being trialled to establish the best combination of available tools. None of the technological solutions evaluated today have instilled confidence in the ability to assess pole conditions accurately. This is work in progress. We participated with the EEA in a working group to develop a national *Timber Pole Conditions Assessment Guide*. This guide has the potential to provide commercial, compliance and intangible benefits to organisations and provide safety assurance benefits to the wider public. It will also aid in:

- consistent benchmarking of asset health assessment information and ratings across all different pole asset owners,
- support improvements in asset management and commercial analysis of investment in pole assets, and
- a consistent industry approach to pole assessment that supports regulatory disclosure and funding models (e.g Commerce Commission).

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 the line 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, and then
- 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 pole with extensive equipment 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, around 1,200 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. As such, we are replacing around 500 poles per annum.

We have approximately 11,000 wood poles and 17,000 concrete 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 better this target to 4,000 poles per annum.

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.

Our replacement and renewal program is incorporated with the conductor replacements and renewals as detailed in section 6.3.7.

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, the 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 6-7.

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 strand galvanised steel conductors in the Mackenzie area has been acceptable and the conductor is not considered at risk of failure.

Table 6-7 Overhead circuit length in km

Voltage	3-phase	1-phase
110 kV	24	N/A
33 kV	227	N/A
22 kV	27	116
11 kV	1948	813
400 V	227	128
Total	**2,501**	**1,028**

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 structure's budgets in Table 6-11. 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 6-8 below.

Table 6-8 Overhead conductor portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	No injuries to the public or contractors as a result from conductor failure. No property damage as a result from conductor failure.
Service levels	Reduced SAIDI and SAIFI by timely conditioned based renewals. Continual refinement of end-of-life predictions techniques.
Cost	Provide cost-effective designs, construction, operational and disposal techniques for all lines. Establish a balance between electrical conductivity and mechanical strength in conductor choice.
Community	Minimise planned outages to 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 6-11 details the overhead conductor length at a sub-transmission level for the types of conductor that we use. All our AAAC conductor is ten years old or younger with a minimal amount of copper still used at sub-transmission level.

Figure 6-11: Sub-transmission conductor age profile in years

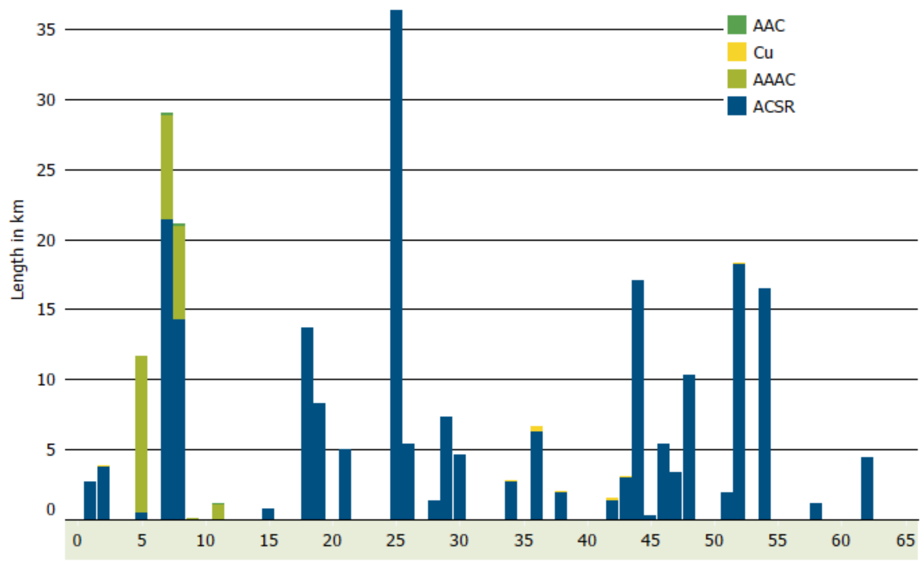
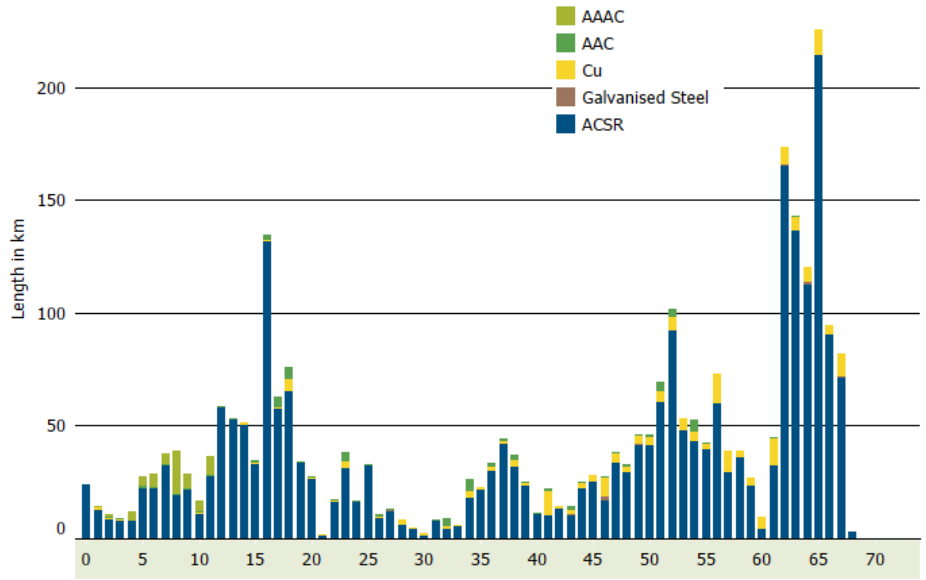


Figure 6-12: Distribution conductor age profile in years



The majority of copper conductor that is 51 years old is short sections in a few our zone substations where it is part of the bus structures. Since these are not under significant tension, we do not regard them as at risk.

ACSR conductor makes up most of our overhead distribution lines and consists mainly of Herring, Gopher, Magpie and Mink types. Details on our ACSR age profile across all voltages are depicted in Figure 6-14. The majority (31%) of our ACSR conductor is of type Herring. Of this, 77% is 50 years or older. On average, we replace and renew our overhead line infrastructure at a rate of 5% per annum. Figure 6-12 depicts our distribution conductor by type, age, and quantity.

Table 6-9: Overhead conductor type length and percentage of total

Type	Length (km)	% of total
AAAC	85	2.4%
AAC	99	2.8%
ACSR	2,801	80.1%
Cu	420	12.0%
other[42]	92	2.6%
TOTAL	**3,491**	**100%**

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

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

Figure 6-13: Low voltage conductor age profile in years

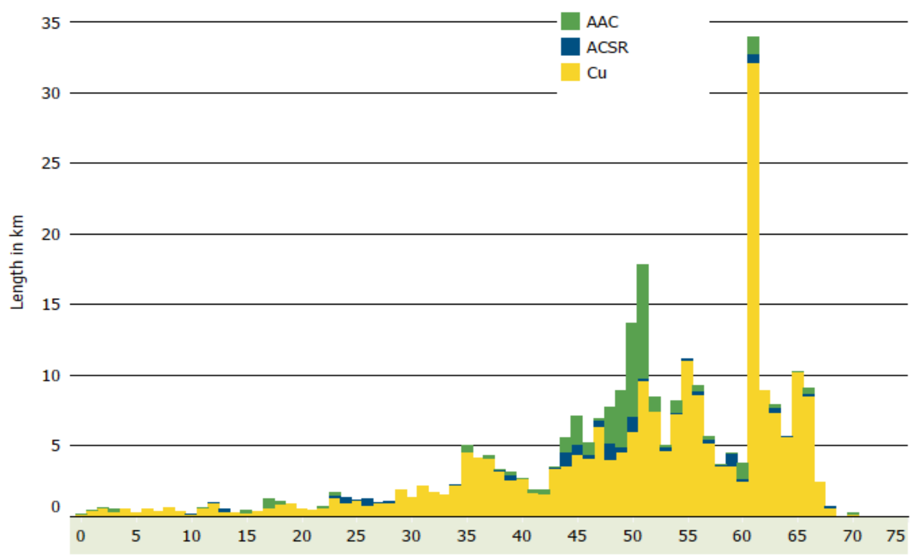
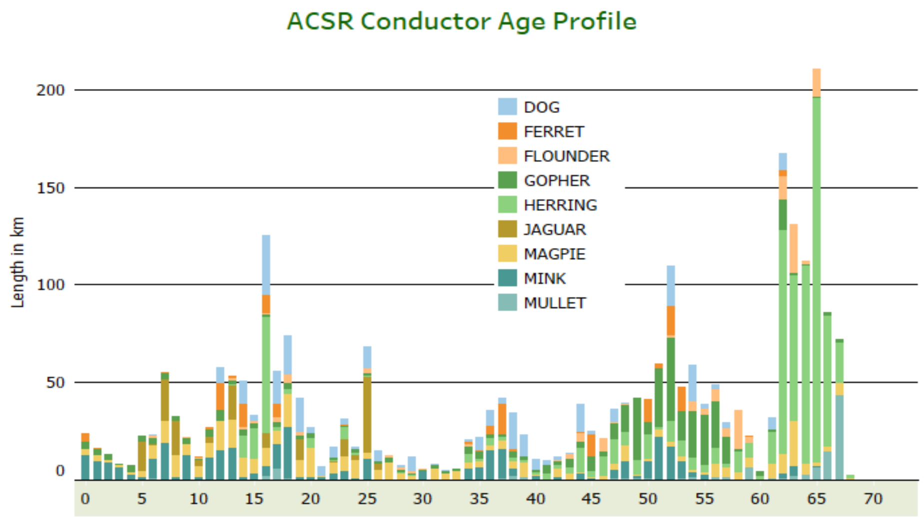


Figure 6-14: ACSR conductor age profile in years



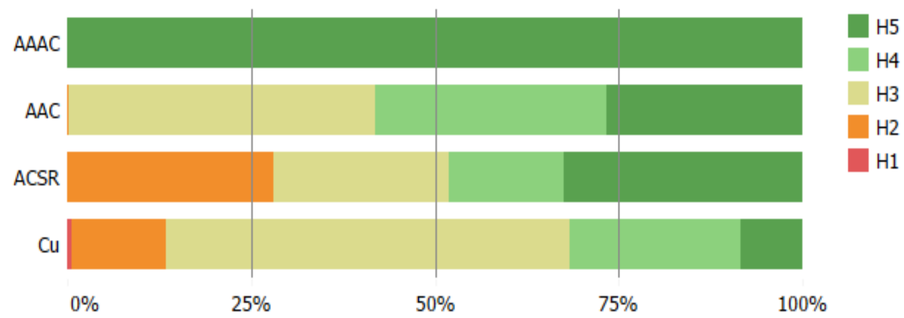
6.3.4 CONDITION, PERFORMANCE AND RISKS

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.

Assessments 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[43] over its lifetime however this has proven to not have been damaging. The aged based[44] asset health profile for overhead conductors are shown in Figure 6-15.

Figure 6-15: Overhead conductor asset health as at 2020



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.

We embarked on a conductor testing regime in 2019 where we took samples of overhead line conductor and had them assessed to determine the remaining life. This regime is ongoing. Our network area is divided into four distinct areas to reflect distance from the ocean and elevation.

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

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

These areas are:

- Zone 1 - within 5 km of the coast – sea spray
- Zone 2 – More than 5 km from the coast and above 200 m elevation
- Zone 3 – between 200 and 550 m elevation
- Zone 4 – above 550 m elevation

The zones are depicted in Figure 6-16. To date, we have tested conductor types in zones as detailed in Table 6-10. The assessment for remaining life is based on the following measures:

- Visual assessment of conductor deterioration,
- Dimension checks,
- Mechanical testing, tensile strength, breaking load, and wrap testing of individual wires (steel and aluminium) in accordance with relevant standards,
- Metallographic assessment,
- Alignment to British Standards BS 251 and Australian Standards AS 3607, and
- Alignment to Transpower standard TP.SS 02.17 - Transmission Line Condition Assessment

In our determination of remaining life for conductors, we have used the recommended criteria of either a 40% loss in ultimate tensile stress of the conductor, or a 20% reduction in cross-sectional area of the aluminium cores. We will review these criteria in consultation with experts as part of the reassessment program.

Table 6-10: ACSR cable type test results

Conductor type	Zone	Sample age (years)	Remaining life (years)	Reassessment (years)
Mullet	3	53	17-30	5-10
Gopher	2	34	116	30-40
Gopher	3	63	147	30-40
Herring	2	57	24-31	12-15
Herring	4	60	24-31	12-15

Our all aluminium conductors (AAC) and all aluminium alloy (AAAC) conductors are in good condition.

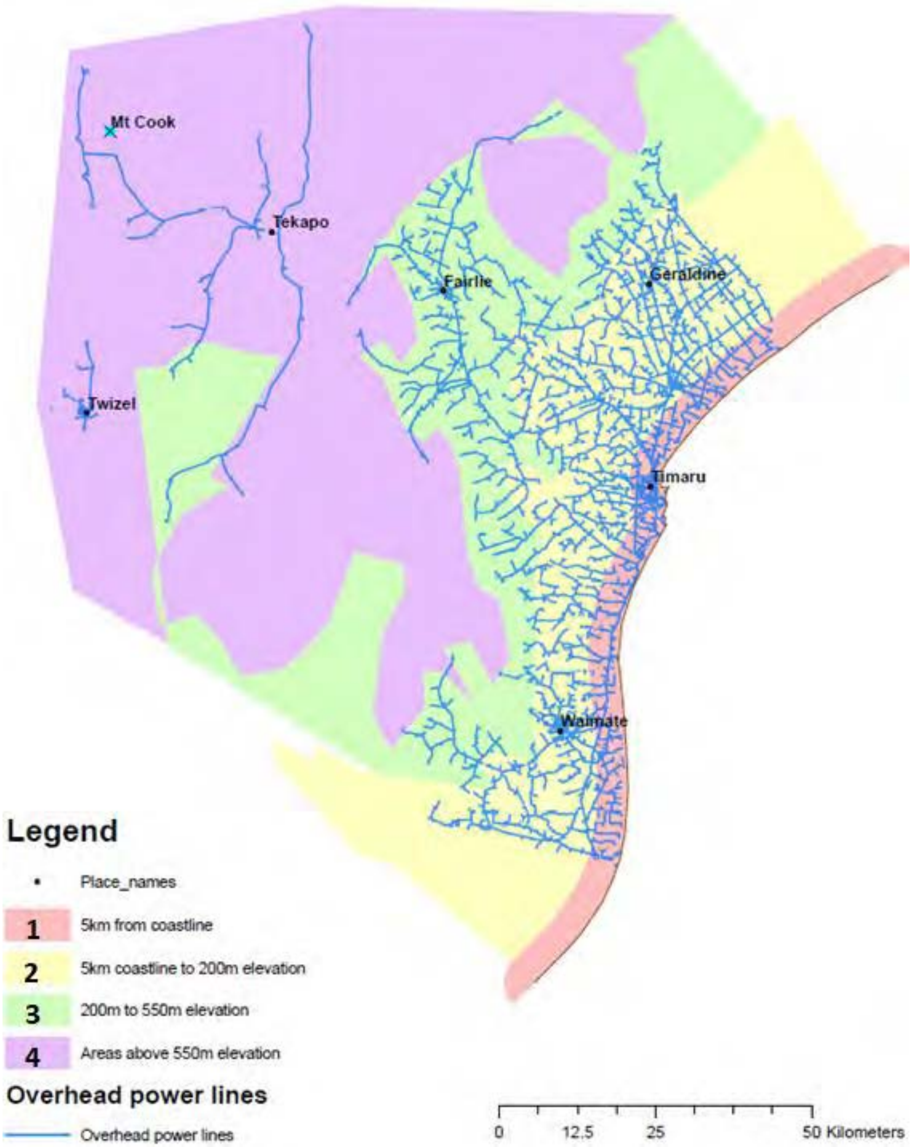
We are participating in a new industry-wide initiative looking to provide a more informative method of identification for predicting the remaining life of conductors.

6.3.5 DESIGN AND CONSTRUCT

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

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

Figure 6-16: Network zones



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, 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 common due to the ease and speed of construction. 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 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.

Our overhead line replacement and renewals for the 2022 period is detailed in Table 6-11.

Table 6-11: Overhead line replacement/renewal program

Where	When	Estimated cost
Pareora: Township – Replace and Renew 237 poles	2022/23	$170 k
Pleasant Point Township - Replace and Renew 309 poles.	2022/23	$200 k
Timaru township – Replace and Renew 1,104 poles.	2022/23	$1.2 M
Smart Munro Road (18km) – Replace and Renew 241 poles.	2022/23	$300 k
SH 1, Cup & Saucer to Makikihi (11.5km) – Replace and Renew.	2022/23	$250 k
TMK-GLD 33kV (17.5km) – Replace and Renew poles.	2022/23	$500 k
Softwood Pole Replacements.	2022/23	$160 k
Twizel township – Replace and Renew 270 poles.	2022/23	$550 k
Lilybank Rd (37km) – Replace and Renew poles.	2022/23	$900 k
Godley Peaks (20km).	2022/23	$500 k
Simons Pass (42km).	2022/23	$1.05 M
McCleays & Archibald, Morven - eplace & Renew - 14km plus replace 1.6 km 16Cu.	2022/23	$300 k
SH8 Stoneleigh Rd to Burkes Pass – Replace and renew poles.	2022/23	$320 k
Braemar Station - 82 poles 33kV – Replace and renew 82 poles.	2022/23	$160 k
Maungati - Craigmore Valley Rd - 41.5km (includes 6.3km of Cu replacement).	2022/23	$760 k
TOTAL		**$7.32 M**

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:

- Sub-transmission cables,
- Distribution cables, and
- 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 SUB-TRANSMISSION CABLES:

The sub-transmission cable fleet predominantly operates at 33 kV, though we also classify our 11 kV Timaru supply cables to the CBD as sub-transmission cables because of their relative importance and mesh configuration compared with the open ring main 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 our 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 last 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 $17 M over the planning period. This includes asset relocations (i.e. overhead to underground conversions), replacement and renewals, and growth projects. This portfolio accounts for 13% of the total expenditure over the planning period.

6.4.2 UNDERGROUND CABLE PORTFOLIO OBJECTIVES

Table 6-12 summarises our underground cable portfolio objectives.

Table 6-12: 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 a risk assessment and risk reduction review. Plan and resource maintenance activities to minimise plant outages.
Community	Appropriate traffic management to minimise disruption in the 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 EEA.

6.4.3 POPULATION AND AGE STATISTICS

Our network contains over 815 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 6-13.

Table 6-13: Underground cable circuit lengths

Voltage	Length (km)	% of total
33 kV	34	4.0%
22 kV	15	1.8%
11 kV	427	50.4%
6.6 kV	7	0.9%
400 V	363	42.9%
TOTAL	**847**	**100.0%**

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[45] 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.

Almost all 33 kV cables on our network are less than 40 years old and are all of XLPE type. The age profile of our sub-transmission cables is shown in Figure 6-17.

Most of our sub-transmission cable that is 15 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 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.

Our LV cables are predominantly XLPE insulated, with a small quantity of older LV PILC cables. The unknown insulation type in Figure 6-19, which are less than 25 years old, we expect are mostly XLPE. We are in the process of reviewing cable data from original as-laid drawings.

[45] For modern XLPE cables.

Figure 6-17: Sub-transmission cable age profile in years

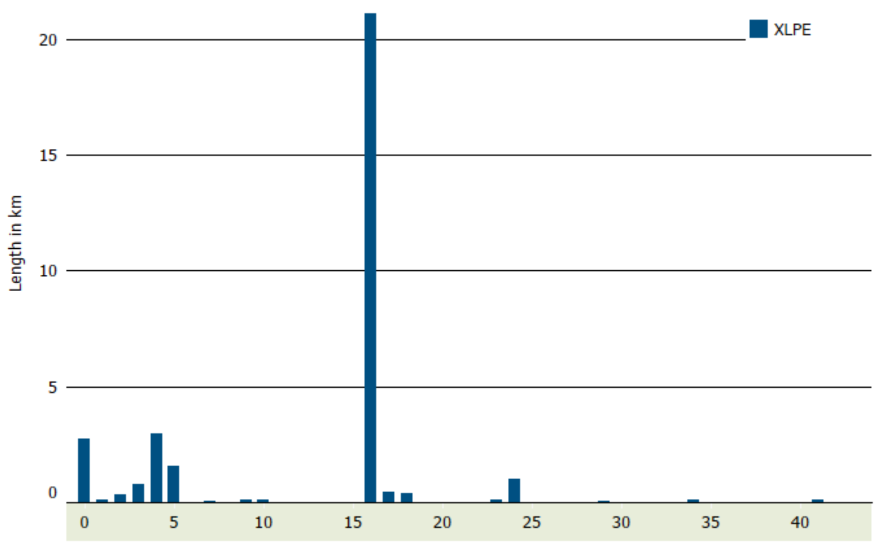


Figure 6-18: Distribution cable age profile in years

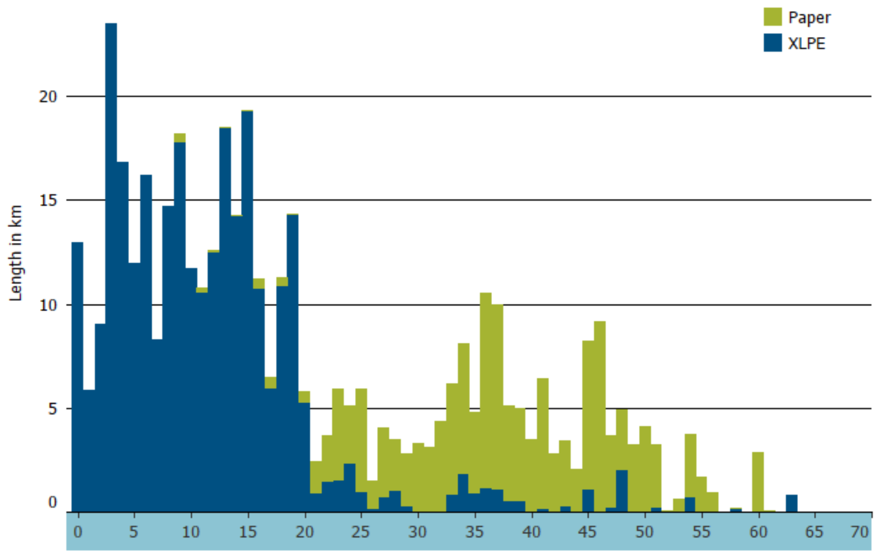
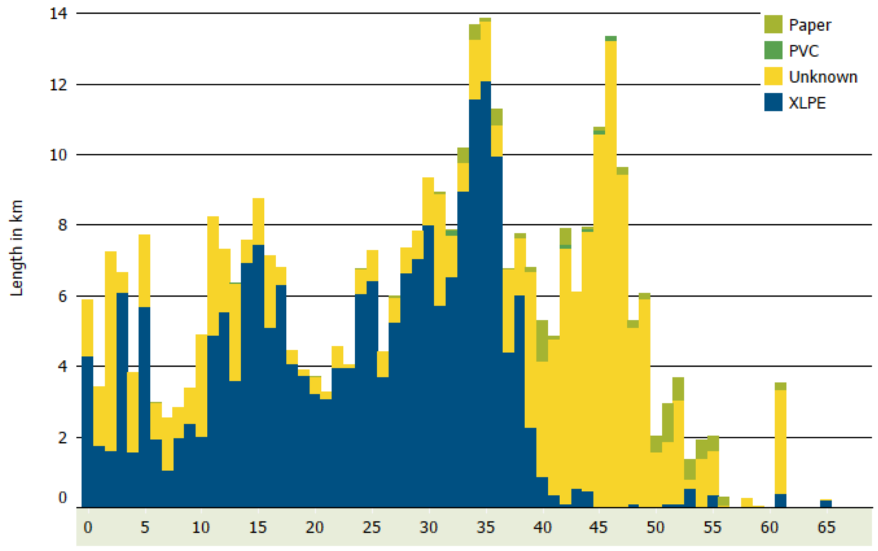


Figure 6-19: Low voltage cable age profile



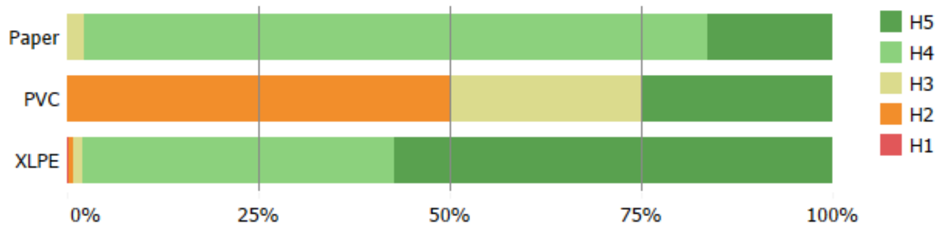
In the absence of reliable data on the longevity of cables of either type under conditions experienced on our network, we have assumed the lifespan of our cables to be the same as that specified by the EEA's *Asset Health Indicator Guide;2016*.

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[46] asset health profile for our distribution cables are shown in Figure 6-20. All our sub-transmission 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 6-20: Underground cable asset health as at 2020



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 to determine the change in cable joint condition. Our cable faults tend to be due to joint failure, unfavourable installation conditions, or a 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 our network are listed in Table 6-14.

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

Table 6-14: Standard cable sizes

Type	Description
Sub-transmission	11 kV and 33 kV - 1C and 3C, Al: 300 mm², 400 mm²; 630 mm², 33 kV 1C Al: 1000/1200 mm².
Distribution	11 kV - 1C and 3 C, Al: 95 mm², 185 mm², 300 mm², 400 mm².
Reticulation	LV neutral screen, 95 mm², 185 mm², and 300 mm².

These cables are aluminium with XLPE insulation. Multicore and single-core cables are used according to the applications. Other conductor sizes may be used, such as when an 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).

For our more important cables (i.e. 33 kV and 11 kV sub-transmission cables), we have adopted VLF partial discharge testing as the preferred HV cable test technique to avoid treeing[47] of the XLPE insulation from HVDC test techniques. For the 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 overstressing 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, and
- Fault repairs due to third-party damage or other cable faults.

[47] 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.

Spare cable and associated cable jointing equipment are 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 21 replacements and have planned five replacements 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.

A zone substation typically takes supply at a voltage level and either step 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.

Portfolio summary

During the planning period we expect to invest $17 M in zone substation renewals. This portfolio accounts for 13% 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, and
- Manage safety risk

6.5.2 PORTFOLIO OBJECTIVES

The portfolio objectives for this fleet are given in Table 6-15 below.

Table 6-15: 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, operation, 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.

6.5.3 ZONE SUBSTATION TRANSFORMER FLEET MANAGEMENT

6.5.3.1 FLEET OVERVIEW

Zone substation transformers, with capacities ranging from 1 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. Figure 6-21 shows a typical zone substation power transformer.

6.5.3.2 POPULATION AND AGE STATISTICS

There are 26 zone substation transformers on our network, of which 19 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. Table 6-16 summarises our population of transformers by rating. Of the 26 units listed one is a 33/11 kV, 5/6.25/9 MVA spare and one is part of our 33/11 kV, 9 MVA mobile substation. We also have two spare 33/11 kV transformers.

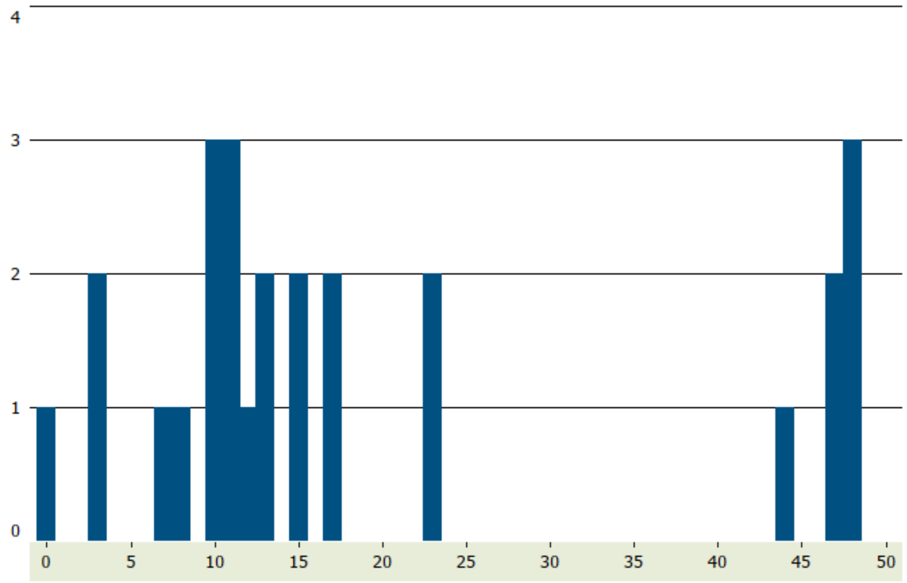
Table 6-16: Zone substation transformer population

Rating	Number	% of Total
< 5 MVA	4	15.3%
≥ 5 and < 9 MVA	5	19.3%
≥ 9 and < 20 MVA	8	26.9%
≥ 20 MVA	10	38.5
TOTAL	**27**	**100%**

Figure 6-21 Zone substation transformer – Cooneys Road substation

Our zone transformers age profile is shown in Figure 6-22. 69% of our zone substation transformers are 20 years old or younger. The rest are between 35 and 48 years old.

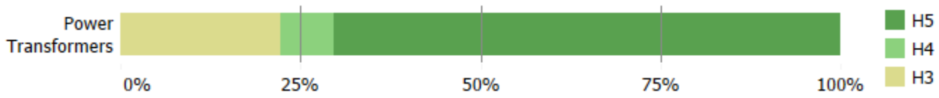
Figure 6-22: Zone substation transformer age profile in years



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[48] asset health profile for power transformers is shown in Figure 6-23.

Figure 6-23: Power transformer asset health as at 2021



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 Table 6-17 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 several 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 6-17.

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

Table 6-17: 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 mechanical/electrical auxiliaries. Insulation and winding resistance tests.	Four yearly and as required by manufacturers' manuals and counters.

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

Mobile substation

Many of our rural zone substations have a single power transformer supply. Some maintenance or planned replacement work requires an outage 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 the 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 6-18.

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. Zone substation security requirements can be a reason for needing additional transformers.

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.

Table 6-18: 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.

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

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

Zone substation power transformer replacement and renewals for this planning period are detailed in Table 6-19.

Table 6-19: Power transformer replacement/renewal program

Zone sub transformer	When	Estimated cost
Twizel Village (TVS)	2023/24	$2.6 M[49]
Pleasant Point	2030	$2.2 M
TOTAL		**$4.8 M**

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 monitoring and inspections are only required for the life of the switchgear.

11 kV Zone Substation indoor switchgear

There are 165 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), 15 are of the bulk oil variety. The vacuum type CBs are used for all new installations and where bulk oil CBs are being replaced.

We only have two zone substations left with bulk oil switchboards at Tekapo and Twizel Village substation. The Twizel Village substation 11kV switchboard will be replaced during the 2022/23 financial year.

[49] This budget estimate includes the rebuild of the complete zone substation; including power transformer bays, switchgear, protection, cables and outdoor structures.

6.5.4.2 POPULATION AND AGE STATISTICS

Table 6-20 summarises our indoor switchgear population by type and number of circuit breakers and switchboards.

Table 6-20: Indoor switchgear population by operating voltage rating and insulating medium

Voltage	Air	Solid Dielectric	SF6	Oil	Total
11 kV	145	2	0	16	163
33 kV	0	1	6		7
TOTAL	**145**	**3**	**6**	**16**	**170**

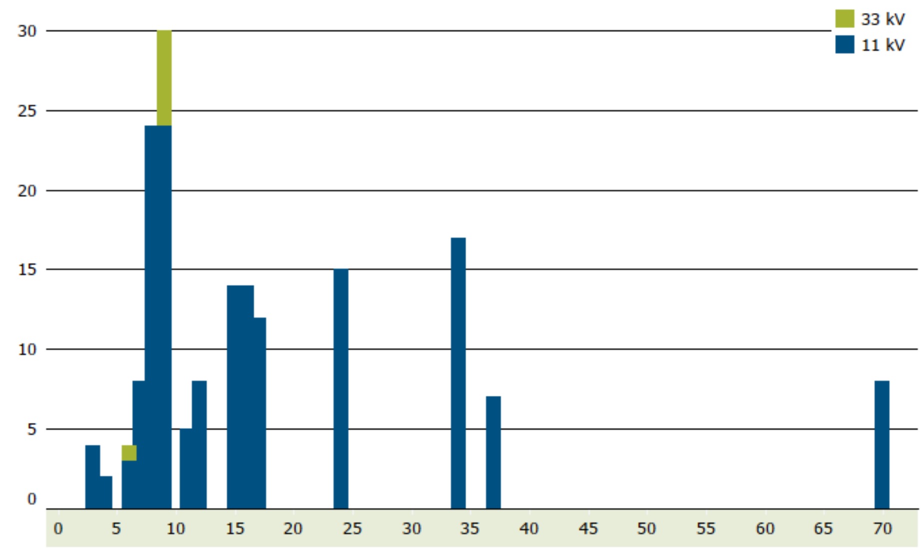
Figure 6-24 11 kV Indoor switchboard at North Street substation

Table 6-21 summarises our indoor switchgear population by make and model. Figure 6-25 show the age profiles for indoor type 33 kV and 11 kV circuit breakers. Our 33 kV CBs are ten years or less. The oldest CBs in our fleet are in the Twizel Village substation with an age of 70 years. The next oldest CBs are located at Tekapo zone substation and are 37 years old.

Table 6-21: Indoor switchgear population by make and model

Type	Make	Model	Voltage	Number	% of Total
Metalclad	RPS	LMVP	11 kV	123	72.4%
	Toshiba	VK10M25	11 kV	17	10.0%
	Tamco	VCB	11 kV	5	2.9%
	South Wales	D6XD	11 kV	7	4.1%
	Thomson Houston	BTH	11 kV	8	4.7%
Metal-enclosed	Areva	GHA	33 kV	6	3.5%
Ring Main Unit	Long & Crawford	L&C	11 kV	1	0.6%
Viper™ Recloser	G&W	Viper-S	11 kV	2	1.2%
Viper™ Recloser	G&W	Viper-S	33 kV	1	0.6%
Total				**170**	**100%**

Figure 6-25: Indoor switchgear age profile in years

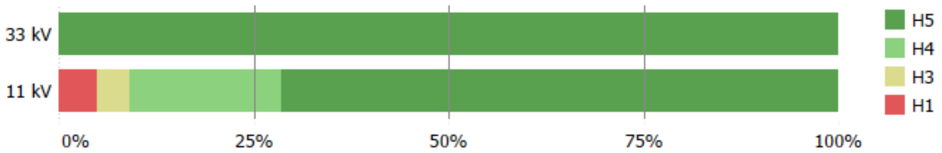


6.5.4.3 CONDITION, PERFORMANCE AND RISKS

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 6-26: Indoor switchgear asset health as 2021



The aged based[50] asset health profile for indoor switchgear is shown in Figure 6-26. About 10% of our indoor switchgear requires replacement over the next ten years.

Arc flash risk

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

Arc flash risk is a safety concern that is considered 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 several existing switchboards to mitigate arc flash risk. 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 as part of our safety in design (SiD) 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 6-22. The detailed regime for each asset is set out in our maintenance standard. Our various routine maintenance tasks are summarised in Table 6-22.

Table 6-22: 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

6.5.4.5 RENEW OR DISPOSE

Indoor switchgear renewal decisions are based upon several factors, as detailed in Table 6-23.

Table 6-23: Summary of indoor switchgear renewal approach

Replacement/renewal trigger	Trigger threshold
Condition	Systemic faults or failure of components. Availability of spare parts or age.
Rating	Capacity is depleted through load growth.
Reliability or Safety	Improve on arc flash risk. Test results inconsistent and not within maximum tolerances.
Economical	Maintenance costs become uneconomical.

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.

Criticality and resilience

In addition to the renewal triggers as listed in Table 6-23, we consider the criticality of the zone substation and the resilience required when we determine the optimum time for replacement.

Renewals forecasting

Only the switchboard at our Twizel Village substation is beyond the maximum practical life of 60 years as defined in the EEA *Asset Health Indicator Guide*. It is also the only switchboard beyond the ODV life of 40 years. Applying the replacement criteria as described above, Table 6-24 details our replacement program for the planning period.

The project planned for 2025/26 at our Hunt Street substation, will not comprise a whole new switchboard but rather only the replacement of the circuit breaker trucks.

Table 6-24: Indoor switchgear replacement program

Zone substation	When	Estimated cost
Twizel Village (TVS)	2022/23	N/A[51]
Tekapo (TEK)	2028/29	$1 M
Hunt Street (HNT)	2025/26	$400 k
TOTAL		**$1.4 M**

[51] This budget estimate is included in the rebuild of the complete zone substation; shown in Table 6-19.

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.

Most of our zone substation outdoor switchgear assets are either 11 kV or 33 kV rated with a small historical amount of 22 kV and recently installed 110 kV switchgear. Table 6-25 summarises our population of outdoor circuit breakers by operating voltage and type.

Table 6-25: Outdoor circuit breaker population by voltage rating and type

Operating Voltage	CB	Recloser	RMU-CB	Total
110 kV	2	-	-	2
33 kV	9	14	-	23
22 kV	2	-	-	2
11 kV	1	6	4	11
TOTAL	**14**	**20**	**4**	**38**

We have 38 outdoor circuit breakers installed at our zone substations and switching stations. The interrupting media comprises oil, vacuum and SF_6 while the insulating medium is either oil, solid dielectric, or SF_6.

Most 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).

Table 6-26 summarises our population of outdoor circuit breakers also broken down by interrupter type.

Table 6-26: Outdoor circuit breaker population by voltage rating and interrupting media

Operating Voltage	Oil	Vacuum	SF6	Total
110 kV	-	-	2	2
33 kV	10	5	8	14
22 kV	1	1	-	11
11 kV	-	7	4	11
TOTAL	**11**	**13**	**14**	**38**

6.5.5.2 POPULATION AND AGE STATISTICS

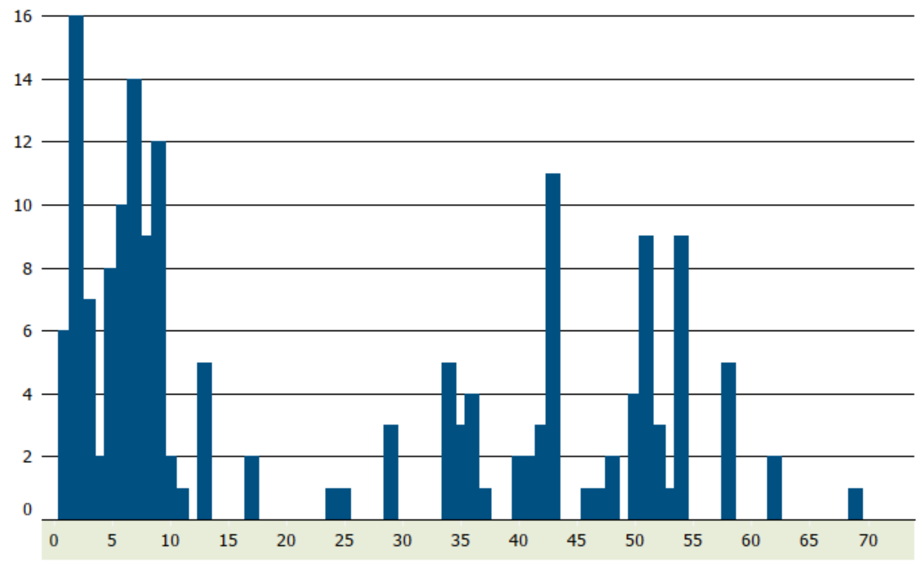
There are four 110 kV rated SF_6 outdoor circuit breakers (CB) on our network. Two of them are currently operated at 33 kV.

There are 23, 33 kV outdoor circuit breakers and reclosers (switchgear) within our zone substations majority of which are oil and vacuum in oil while recent 33 kV switchgear are SF_6 insulated. 33 kV CBs typically carry a function of protecting power transformers and/or sub-transmission lines.

There are only eleven 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.

Figure 6-27 show the age profile for all zone substation outdoor switchgear. This also includes air break switches, links and fuse links. Since these additional types of switchgear is not as critical as circuit breakers, the age profile and asset health profile should be considered with this fact in mind. The majority of switchgear older than 40 years of age are air break switches and links. Only the PLP and TVS zone substations have circuit breakers that are 40 years or older.

Figure 6-27: 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 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 have 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.

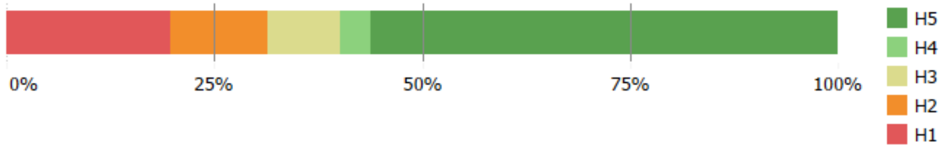
For outdoor switchgear, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely. The switchgear condition is primarily evaluated using asset age, typical expected life and condition assessment.

The aged based[52] asset health profile for outdoor switchgear is shown in Figure 6-28. It is important to note that the health level H1 comprises mainly air break switches which are maintained as part

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

of the four-yearly zone substation maintenance program. They are located at our Timaru, Twizel, Tekapo, and Temuka substations. The AHI is not reflective of outdoor circuit breakers.[53]

Figure 6-28: Outdoor switchgear asset health as at 2021



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 solution for the network is utilised.

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) based on 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 6-27. The detailed regime for each asset is set out in our *Outdoor Switchgear Maintenance Standard*.

Table 6-27: 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-test circuit breakers including thermal, PD and acoustic emission scan.	Yearly
Circuit breaker insulation, contact resistance and operational tests. Service of oil circuit breakers. Mechanical checks. ABS thermal scan. Recloser thermal and oil insulation tests.	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.

[53] The AHI for outdoor circuit breakers is depicted in schedule 12a) of the IDs in Appendix A2.3

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.

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. Vacuum circuit breakers are preferred over SF_6 as it has a lower carbon footprint, but an existing substation's real estate area may necessitate the use of SF_6 breakers because they are more compact.

Our in-service OCBs are generally in good condition with no partial discharge issues detected to date, but they 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 6-28: Outdoor switchgear renewal approach

Replacement/renewal trigger	Trigger threshold
Condition	Systemic faults or failure of components. Availability of spare parts or age.
Rating	Capacity is depleted through load growth.
Reliability or Safety.	Improve on arc flash risk. Test results inconsistent and not within maximum tolerances.
Economical	Maintenance costs become uneconomical.

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 be replaced 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.

Applying the replacement criteria as described above, Table 6-29 details our replacement program for the planning period.

Table 6-29: Outdoor switchgear replacement program

Unit / Location	When	Estimated cost
Z68 / Twizel Village (TVS)	2022/23	N/A[54]
L250 / Pleasant Point (PLP)	2022/23	$200 k
TIM 33 kV	2023/24	$600 k
TOTAL		**$800 k**

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. Most zone substations have numerical protection relays installed. These are the industry standard and allow for the 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

Table 6-30 below details the type, number, and proportion of protection relays on our network.

Table 6-30: Zone substation protection relay population

Relay Type	Quantity	% of total
Electromechanical	41	9%
Static	29	6%
Digital	377	85%
TOTAL	**447**	**100%**

[54] This budget estimate is included in the rebuild of the complete zone substation; shown in Table 6-19.

Our protection relay fleet is relatively modern with 92% of all relays installed in the last 15 years. The use of modern relays allows for the implementation of advanced functions that provide superior protection of equipment and reduce nuisance outages for consumers.

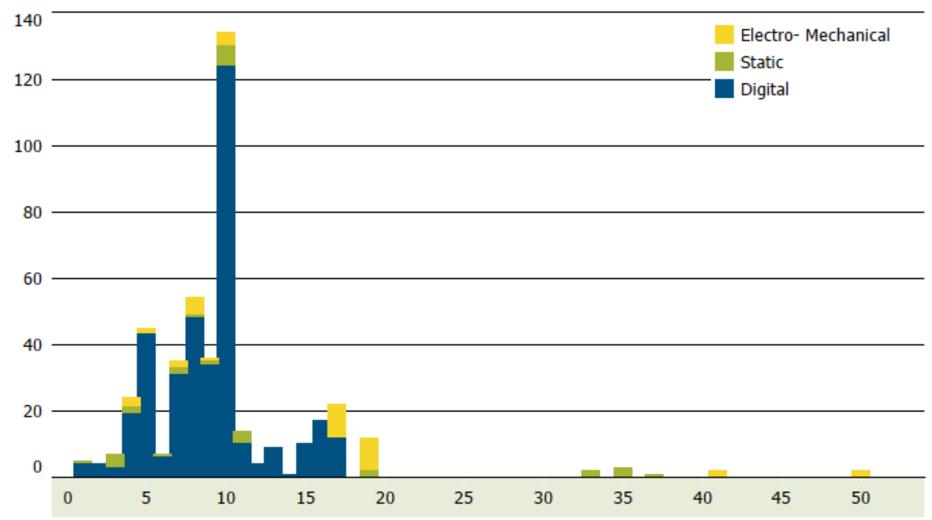
Figure 6-29 shows a summary of our protection relay population based on age and quantity. The useful life of the various types of relays we have on our network is detailed in Table 6-31.

Table 6-31: Protection relay useful life

Relay Type	Useful Life (years)
Digital	25
Static	25
Electromechanical	30-40

We have two electromechanical relays that are 50 years at our Twizel Village zone substation and another two at our Timaru zone substation that are 41 years old. The Twizel Village zone substation is planned to be refurbished in 2022/23 at which time these relays will be replaced. The Timaru zone substation is planned to be refurbished within the first five years of the planning period at which time these relays will be replaced. These relays are still subject to our four-yearly zone substation protection testing and maintenance regime.

Figure 6-29: Zone Substation protection relays age profile in years



6.5.6.3 OPERATE AND MAINTAIN

Digital relays can 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 digital protection relays on our network are connected for remote control and interrogation. Digital relays have a dominant failure mode associated with the degradation of capacitors in their power supply circuitry. Digital 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 digital relays are all self-monitoring and are only required to be tested once every ten years. However, since the protection system measuring circuits and the trip circuits, including the circuit breaker trips, are required to be tested every four years, we have decided to also test all the protection relays as part of this maintenance schedule.

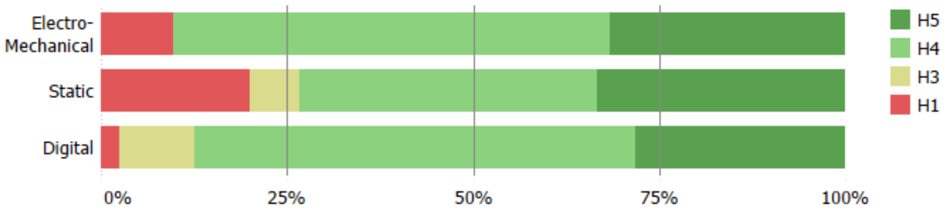
6.5.6.4 CONDITION, PERFORMANCE AND RISKS

Protection relay age is one indicator of its reliability. Electromechanical, static, and digital 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 have been able to function reliably for over 50 years. After this time, the unit is typically not worth repairing, and replacement with a modern digital relay is recommended where this is appropriate.

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.

Most zone substations provide climatic controls to limit the temperature/humidity extremes that the relays are exposed to. This assists in extending the life of all components and the relay itself. The age based asset health profile for our protection relays are shown in Figure 6-30.

Figure 6-30: Protection relay asset health as at 2021



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

6.5.6.5 RENEW OR DISPOSE

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

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.

Our replacement program for the planning period is detailed in Table 6-32.

Table 6-32: Protection relay replacement program

Unit / Location	When	Estimated cost
TIM	2022/23[55]	$150 k
TVS	2022/23	N/A[56]
CD2 AVR	2024/25	$60 k
CD2	2025/26	$350 k
GLD	2026/27	$150 k
STU	2027/28	$250 k
CD1	2028/29	$75 k
TMK	2031/32	$200 k
TOTAL		**$1.235 M**

6.5.7 ZONE SUBSTATION BULK METERING

6.5.7.1 FLEET OVERVIEW

We have digital revenue and check meters installed in some zone substations to either provide revenue metering to our customers, supplied at 11 kV, or as check meters. The MEPs (Metering Equipment Providers) look at the revenue meters, and these meters are not usually connected to

[55] This project is dependent on the possible GXP upgrade by Transpower

[56] This budget estimate is included in the rebuild of the complete zone substation; as given in Table 6-19.

our SCADA network. The check meters are connected to our SCADA network so that these can be monitored remotely.

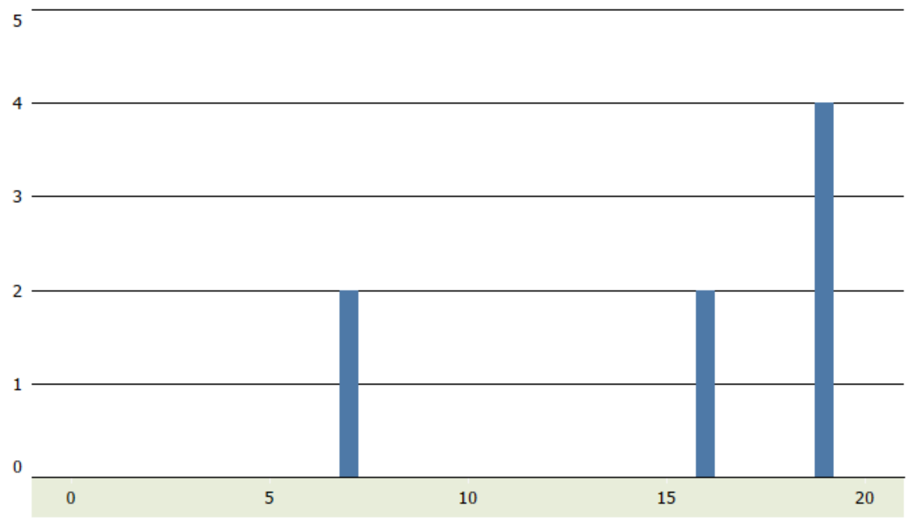
6.5.7.2 POPULATION AND AGE STATISTICS

We have eight digital revenue and six digital check meters installed. Table 6-16 summarises our population of zone substation metering equipment, and Figure 6-31 shows the age profile of the revenue meters.

Table 6-33: Zone substation metering population

Age (years)	Number	% of Total
5 to ≤ 10	2	50%
11 to ≤ 15	2	25%
16 to ≤ 20	4	50%
TOTAL	**14**	**100%**

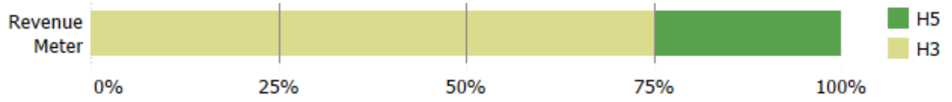
Figure 6-31: Zone Substation based revenue meter age profile in years



6.5.7.3 CONDITION, PERFORMANCE AND RISKS

The revenue and check meters are not critical in maintaining our supply to consumers. There are also no safety and environmental considerations associated with revenue meters. The age based asset health profile for our zone substation based revenue meters are shown in Figure 6-32.

Figure 6-32: Zone substation based revenue meter asset health as at 2021



6.5.7.4 DESIGN AND CONSTRUCT

We work together with the MEPs to apply, maintain, and improve their capability to design, test and install metering technology within our network. It is the MEPs responsibility to ensure that the revenue meters are calibrated and that the metering installations are certified.

6.5.7.5 OPERATE AND MAINTAIN

The maintenance requirements for revenue meters are prescribed by the Electricity Industry Participation Code 2010 and are the responsibility of the MEPs. The MEP will handle the failure of a revenue meter, and we will replace faulty meters. We enable the MEPs to conduct annual inspections and certification of the revenue meters and ensure their continued safe and reliable operation.

6.5.7.6 RENEW OR DISPOSE

The eight revenue meters are considered to have a life expectancy of 20 years. The four revenue meters at CD1 (Clandeboye 1 substation) are 17 years old and will be replaced in 2022/23 and 2023/24. The two revenue meters at CD2 (Clandeboye 2 substation) will be replaced in 2023/2024. Two of the revenue meters at CD1 are on the incomers, while the other two are on external feeders of our network.

For Fonterra Clandeboye to be billed correctly, it is necessary to subtract the meter readings for the two external feeders from the meter readings for the two incomer revenue meters. This metering scheme is not usually allowed, though we have a ten-year dispensation to operate the subtraction scheme. This dispensation expires on 31 December 2024. We will not be allowed to continue the subtraction scheme once the revenue meters are upgraded. We will thus engage an MEP to fit new revenue meters and associated CTs (Current Transformers) on nine Clandeboye feeders in 2022/23 and 2023/24, at an expected total cost of $300 k.

6.5.8 BUILDINGS FLEET MANAGEMENT

6.5.8.1 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.

6.5.8.2 POPULATION AND AGE STATISTICS

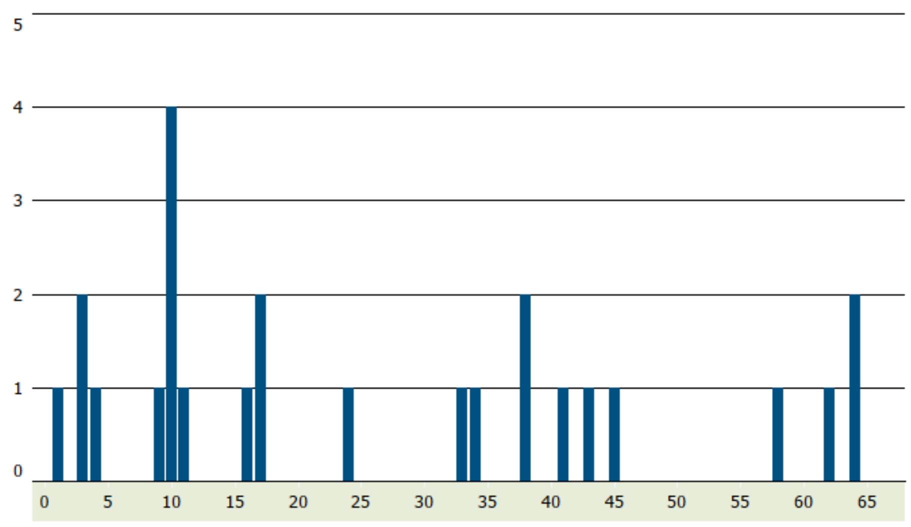
We have 28 buildings located within our zone substations. These are constructed of various materials, including mainly steel-reinforced concrete, steel 'insulated' sandwich panel and some timber frame.

Table 6-34 summarises our population of zone substation buildings by age groups.

Table 6-34: Zone substation building population

Age (years)	Number	% of total
≤10	9	34%
11 to ≤20	4	15%
21 to ≤30	3	12%
31 to ≤40	1	4%
41 to ≤50	4	15%
51 to ≤60	2	8%
61 to ≤70	3	12%
TOTAL	**28**	**100%**

Figure 6-33: Zone substation buildings age profile in years



6.5.8.3 CONDITION, PERFORMANCE AND RISKS

The condition of our zone substation buildings is generally good to excellent with a few 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~~.~~

Three of our ripple plant buildings are of older timber frame construction and are generally sound but 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, and the last has recently had its galvanised steel roof replaced. All three 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. If 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.

6.5.8.4 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). For new ripple plant buildings, we use purpose fitted and painted shipping containers.

6.5.8.5 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 6-35: Zone substation building maintenance and inspection tasks

Replacement/renewal trigger	Trigger threshold
General visual inspections and housekeeping	Monthly
More detailed inspections	Yearly

6.5.8.6 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 portacom-type structures during the planning period. In addition, our Hunt Street switching station building will be risk assessed and possible alterations made to replace the glazed parts with more suitable cladding.

Our replacement/renewal program for the planning period is detailed in Table 6-36.

Table 6-36: Zone substation building replacement program

Unit / Location	When	Estimated cost
Twizel Village (TVS)	2022/23	N/A[57]
Hunt Street switching station	2023/24	$100 k
TOTAL		**$100 k**

[57] This budget estimate is included in the rebuild of the complete zone substation and is given in Table 6-19.

6.5.9 LOAD CONTROL INJECTION PLANT FLEET MANAGEMENT

6.5.9.1 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 shed load, such as irrigation, when required.

If configured well, load control systems effectively reduce 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 6-34 Load control injection plant – Bells Pond zone substation

6.5.9.2 POPULATION AND AGE STATISTICS

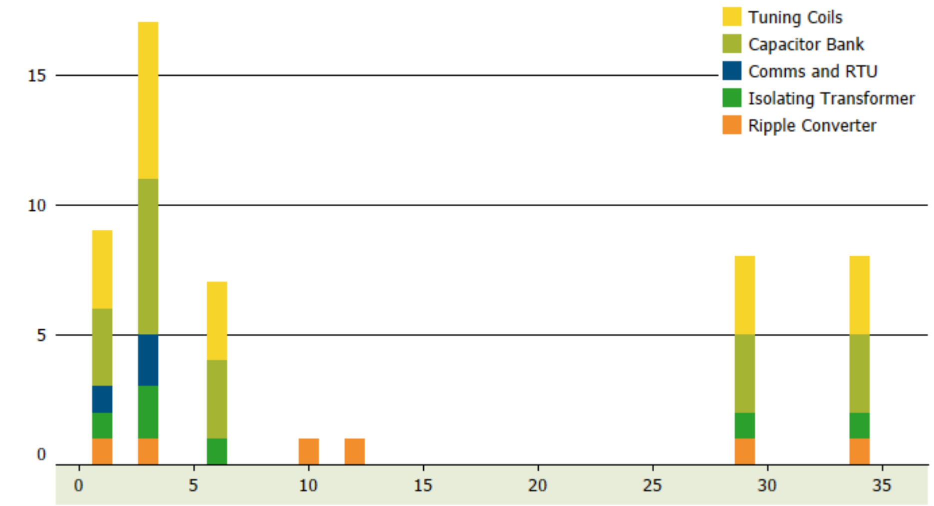
We currently operate load control injection plants on our network, comprising both modern and aged equipment. Table 6-37 summarises our load control injection plant population by type.

Table 6-37: Zone substation load control injection plant population

Type	Plant	% of Total
Modern electronic plant	6	86%
Legacy rotary plant	1	14%

TOTAL	7	100%

Figure 6-35: Zone substation load control injection plant age profile in years



6.5.9.3 CONDITION, PERFORMANCE AND RISKS

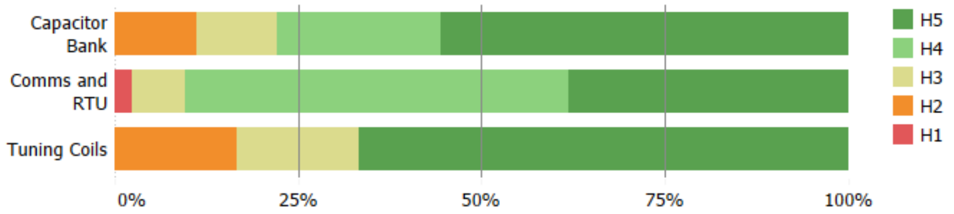
A new ripple plant was commissioned at our Albury zone substation in 2017 after the building was refurbished.

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 a 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. This strategy will, however, be reviewed on an annual basis to ensure we meet network growth, operational and retailer commitments.

The age based asset health profile for our ripple plants are shown in Figure 6-36.

Three of our load control injection 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 its end-of-life and will then be decommissioned. This strategy will be reviewed on an annual basis.

Figure 6-36: Load control plant asset health as at 2021



6.5.9.4 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.

6.5.9.5 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 6-38: Load control plant maintenance and inspection tasks

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

6.5.9.6 RENEW OR DISPOSE

The legacy load control plant installation 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 clock, as mentioned before. Apart from this legacy plant, we will renew the ripple plants to maintain the functionality of the existing fleet. Our load control plant replacement/renewal program for the planning period is detailed in Table 6-39.

Table 6-39: Load control plant replacement

Unit / Location	When	Estimated cost
TMK	2022/23	$350 k
STU	2023/24	$150 k

Unit / Location	When	Estimated cost
BPD	2025/26	$200 k
TOTAL		**$700 k**

6.5.10 OTHER ZONE SUBSTATION ASSET FLEET MANAGEMENT

6.5.10.1 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. 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.

6.5.10.2 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.

We use consultants to carry out current injection testing of most of our zone substations to evaluate the step and touch voltage hazards. As part of the testing, the crushed rock layer is also inspected. Areas where we deviate from the industry guidelines for earthing, are fixed by installing additional deep driven earth rods and extending earth mats. Due to the types of soil we have across our network earth resistance values change dramatically and in cases it is impossible to meet industry guidelines. We evaluate the risk based on likelihood and consequence when deciding to what extent we attempt to reduce system earth resistance values to align with the industry guidelines.

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.

6.5.10.3 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 the installation of an 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.

6.5.10.4 OPERATE AND MAINTAIN

Our general zone substation maintenance tasks are summarised in Table 6-40. The detailed regime is set out in our maintenance standards.

Table 6-40: 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 carrying out current injection testing. Crushed rock inspection.	Ten yearly.

6.5.10.5 RENEW OR DISPOSE

Faulty components and assets are replaced/repaired as required.

6.5.11 MOBILE EQUIPMENT

6.5.11.1 FLEET OVERVIEW

Our mobile asset fleet consist of a mobile substation and a few standby diesel generators. The mobile substation functions as a zone substation and we have the ability to transform voltages from 33 kV to 11 kV, or use it as a step-up zone substation. The mobile substation comprises of a single 33 kV circuit breaker and two 11 kV feeder circuit breakers, a 9 MVA power transformer and all associated protection systems.

Our mobile diesel generators are detailed in Table 6-41.

Table 6-41: Mobile generation fleet details

Number	Size	Connection voltage
2	810 kVA	400 V or 11 kV
1	275 kVA	400 V

Number	Size	Connection voltage
1	150 kVA	400 V
6	6.5 kVA	230 V

6.5.11.2 OPERATE AND MAINTAIN

We utilise the mobile substation mainly for planned zone substation maintenance. It allows us to remove a complete zone substation from service. This includes the zone substation power transformer, all switchgear, and associated protections systems, as well as the DC supply system.

The mobile substation is put into service, and the permanent substation to be maintained is removed from service, without any power interruption to our consumers. Planned maintenance and asset replacement work can then progress without a power supply interruption.

The mobile substation can also be used for unplanned outages related to zone substation primary and/or secondary system failures.

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, and
- Other distribution transformers, which includes voltage regulator, capacitor, 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 $23 M over the planning period. This portfolio accounts for 17% 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. Transformer 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 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, as detailed in Table 6-42.

Table 6-42: 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 the location of any new distribution substations and impact on residents or businesses. Consult with community on the 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 suburban areas where the supply is overhead, the larger pole-mounted transformers are referred to as two-pole substations, as depicted in Figure 6-37.

The majority of our ground-mounted distribution transformers are 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 6-38.

Voltage regulators improve the voltage levels on long distribution lines, and as such, they do not strictly provide a power supply to consumers, but rather ensures the supply is of acceptable quality. Most of our voltage regulators are pole mounted and an example in shown in Figure 6-38.

Figure 6-37: Pole mounted distribution transformers

Figure 6-38: Ground mounted transformer (left) and voltage regulator (right)

6.6.4 POPULATION AND AGE STATISTICS

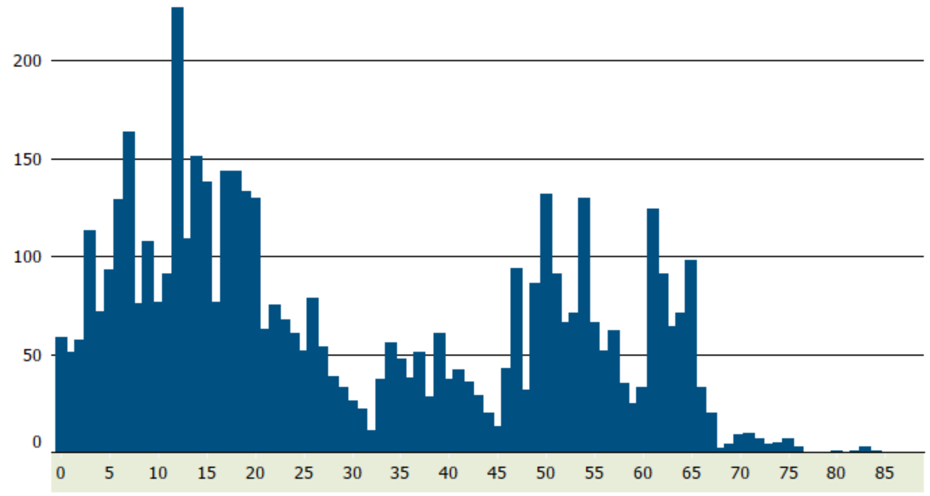
Distribution substations and transformers step down the voltage for local distribution. We have 6,208 oil-filled distribution transformers in service, and the age profile resembles that of the 11 kV overhead lines and cables. The most significant investments in distribution substations and transformers were made in the late 1950s, early 1970s, 2000s, and 2010s.

Table 6-43: Distribution transformer population by rating

Rating	Number	% of Total
≤ 15 kVA	2,658	44%
>15 and ≤ 30 kVA	1,143	19%
>30 and ≤ 100 kVA	1,073	18%
>100 and ≤ 250 kVA	609	10%
>250 and ≤ 500 kVA	421	7%
>500 and ≤ 1500 kVA	162	3%
TOTAL	**6,066**	**100%**

The in-service distribution transformers by kVA rating and percentage of the overall population is given in Table 6-43. The age profiles for pole mounted and ground mounted distribution transformers are given in Figure 6-39 and Figure 6-40, respectively.

Figure 6-39: Pole mounted distribution transformer age profile in years



The expected life of pole-mounted units typically ranges from 45 to 60 years and beyond. While most of our distribution transformers are less than 30 years old, some are older than 60 years. These are all small transformers of 3 kVA to 30 kVA in size.

We have some 34 voltage regulator sites installed on our network. They comprise mainly of two-can installations with some three-can installations. The majority is less than fifteen years old and reflects the increase in rural load on our network because of dairy conversions and on farm irrigation that started in the early 2000s. The age profile depicted in Figure 6-41 counts individual phases or cans. We have changed the way we record these on our asset register where each individual can constitute an individual asset.

Figure 6-40: Ground-mounted distribution transformer age profile in years

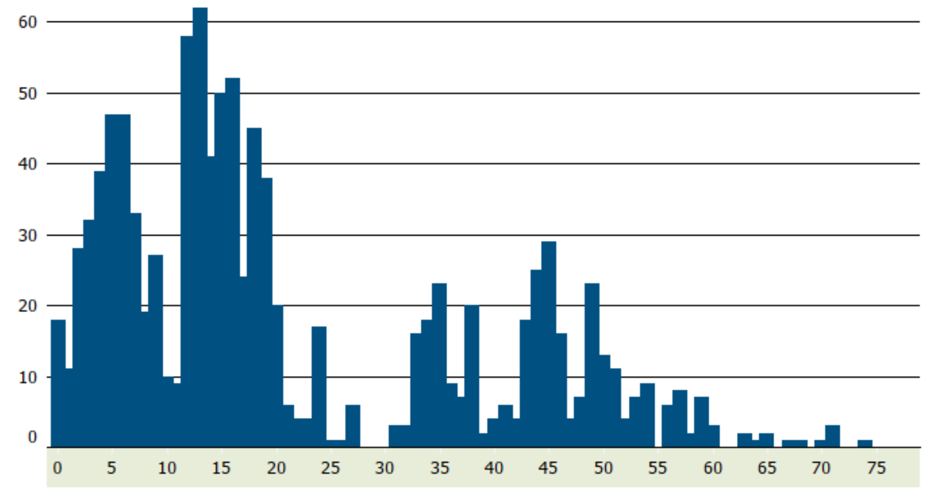
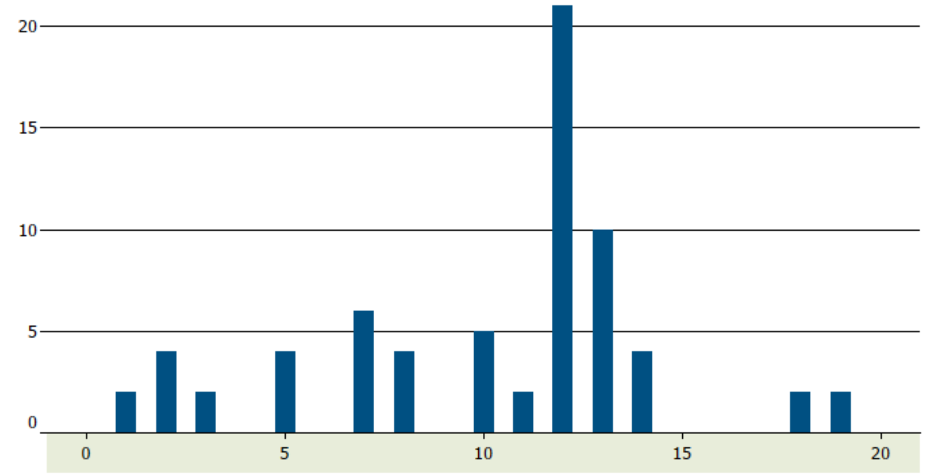


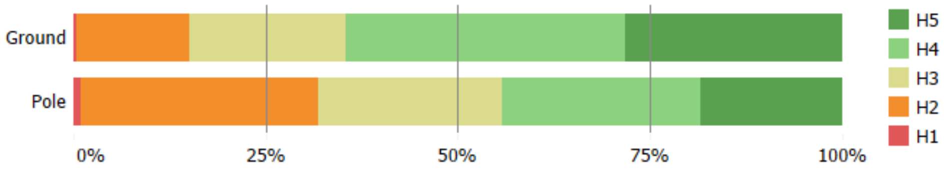
Figure 6-41: Voltage regulator age profile in years



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 age based[58] asset health profile for our distribution transformers are shown in Figure 6-42.

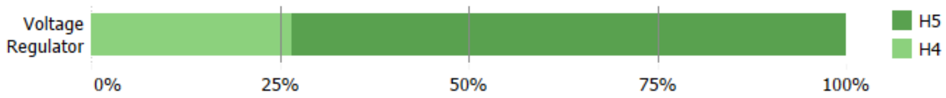
Figure 6-42: Distribution transformer asset health as at 2021



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

The aged based[59] asset health profile for voltage regulators are shown in Figure 6-43. From the graph our regulator fleet is young compared to the ODV expected end of life of 55 years.

Figure 6-43: Voltage regulator asset health as at 2021



6.6.6 DESIGN AND CONSTRUCT

Distribution transformers are designed and constructed to international standards. Our distribution transformer suppliers design and test 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 because 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 prepared by registered chartered engineers to ensure withstanding earthquakes.

6.6.7 OPERATE AND MAINTAIN

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

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

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-year 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 because 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.

Pole-mounted distribution transformers are replaced as part of the overhead line and pole structure renewal and renewal program when their condition is classified as AHI level 1. Most pole-mounted transformer replacements are as a result of lightning. This varies year on year, but on average we replace approximately ten units of various sizes.

Ground-mounted distribution transformers are replaced based on condition or as part of our underground substation replacement program. We aim to replace all 30 remaining underground substations with above ground equivalents at three to four per annum. Table 6-44 summarises the projected expenditure for distribution transformer and underground substation replacements for the planning period. This expenditure forecast includes the replacement of RMUs and associated cable work associated with the underground substations.

Table 6-44: Distribution transformer replacement/renewal program

Unit / Location	When	Estimated cost
Timaru	2022/23	$1.2 M
Timaru	2023/24	$1.2 M
Timaru	2024/25	$1.2 M
Timaru	2025/26	$1.2 M
Timaru	2026/27	$1.2 M

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

Unit / Location	When	Estimated cost
Timaru	2027/28	$1.2 M
Timaru	2028/29	$1.2 M
Timaru	2029/30	$1.2 M
Timaru	2030/31	$1.2 M
Timaru	2031/32	$1.2 M
TOTAL		**$12 M**

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, is also given. The portfolio includes the following fleets:

- **Ground mounted switchgear** which consists mainly of RMUs (Ring Main Units), 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 6-44, with the red arrows pointing to a fuse link on the left and an ABS on the right.

Figure 6-44 Fuse link & ABS left, and a recloser right

6.7.2 PORTFOLIO OBJECTIVES

The portfolio objectives for our distribution switchgear fleet is summarised in Table 6-45.

Table 6-45 Distribution switchgear portfolio objectives

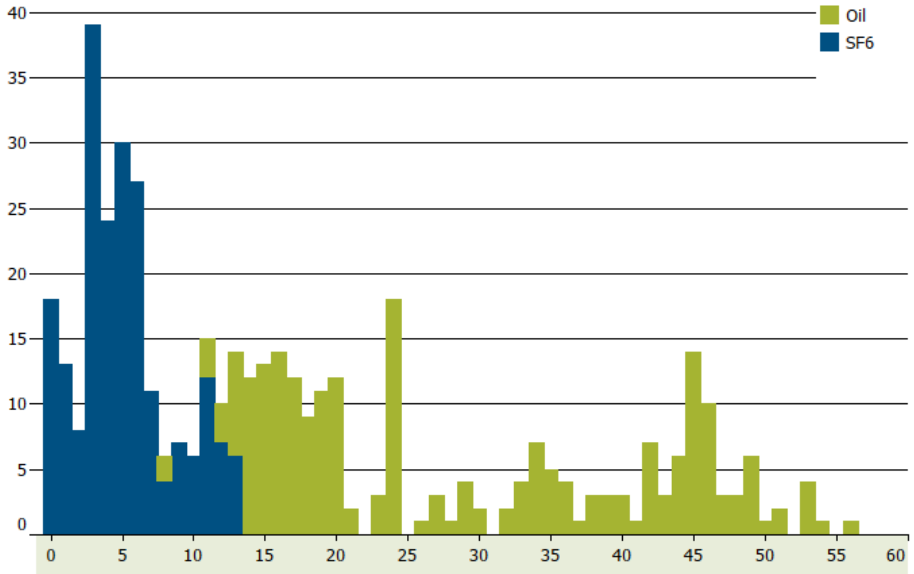
Asset management objective	Portfolio objective
Safety & environment.	No injuries due to failure or operation of switchgear. No significant SF6 leaks.
Service levels	Continue program to automate reclosers and voltage regulators. Investigate the use of low-cost automated devices as tie switches.
Cost	Cost-effective 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 6-45 shows our population and age profile for our RMU types on our network. We have a total of 435 RMUs on our network, 239 (55%) oil insulated and 196 (45%) are gas insulated. Around 15% (all oil) are at or just beyond the ODV life of 40 years.

Figure 6-45: RMU age profile in years



As shown in Figure 6-45 our SF_6 insulated RMUs are relatively new with the oldest just on fourteen years of age. We have standardised on three types of RMUs for new and replacement projects, all of which are gas (SF_6) insulated.

6.7.3.2 POLE MOUNTED FUSES AND SWITCHES

We have approximately 6891 pole-mounted fuses and switches on our network with ages as shown in Figure 6-46 and Figure 6-47 respectively.

A significant proportion of pole-mounted fuses and switches are less than 20 years old, while some date from nearly 60 years ago. They are simple pieces of equipment and maintenance revolves typically around the lubrication of moving parts. Since these switches are maintained as part of the overhead line pole maintenance and replacement program, their condition is better than the age profile would suggest if age alone is taken as a metric of condition.

Figure 6-46: Pole fuse age profile in years

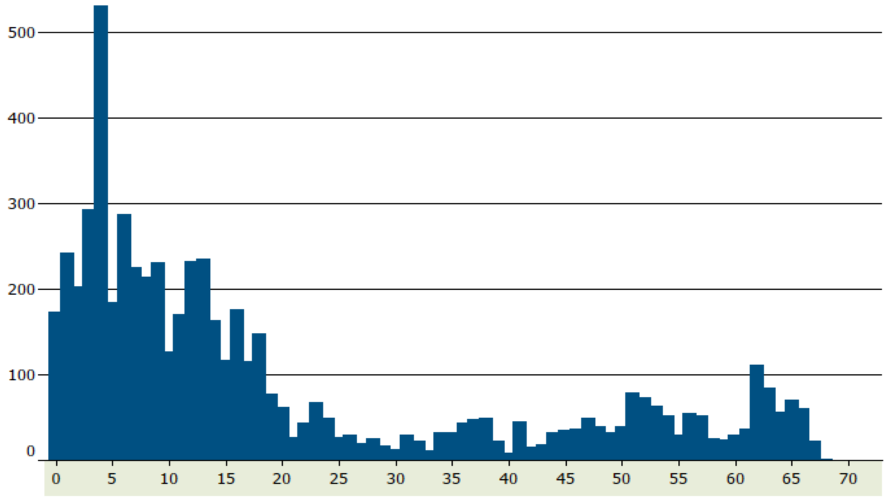
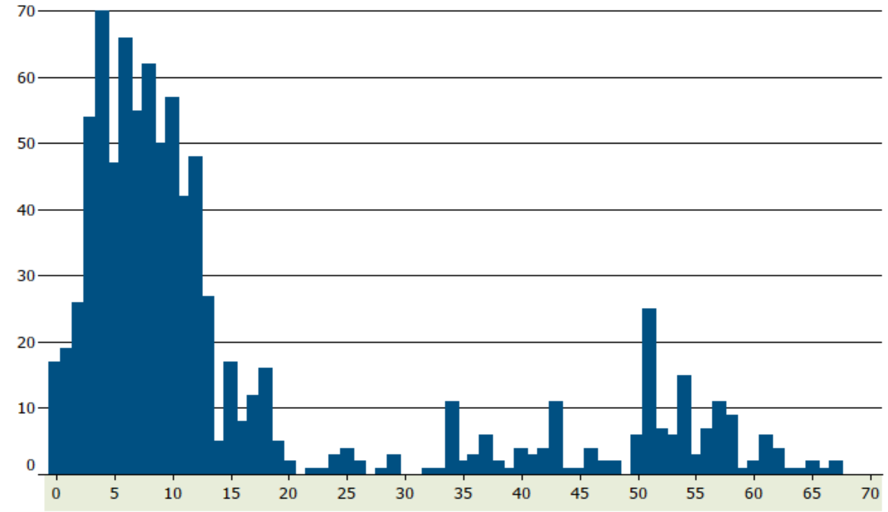


Figure 6-47: Pole switch age profile in years



Since the majority of pole-mounted fuses are pole-mounted transformer fuses, a single set supplies a fairly low number of ICPs and in many instances a single ICP. Based on the small number of ICPs supplied, these devices are of a lower criticality level compared to a ring main unit fuse which can typically supply more than a hundred ICPs.

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 6-46. 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 is improved.

Reclosers are pole-mounted switches that can break fault currents. The recloser isolates a fault downstream of the recloser location and preserves the quality of supply for all upstream customers. The reclosers can connect to control units that allow them to re-energise a circuit following an interruption. The control unit strives to restore the supply with minimal delay in the event of a recoverable fault, such as a bird or strong winds causing a line clash. The recloser controller can be maintained and replaced separately from the recloser.

Table 6-46 summarises the types and quantities of the different reclosers that we use on our network. The age profile of the reclosers are shown in Figure 6-49, while Figure 6-50 shows the age profile of the recloser controllers.

Table 6-46: Recloser types and quantities

Type	Quantity
Vacuum interrupter & oil insulation.	13
Vacuum interrupter & SF_6 insulation.	2
Vacuum interrupter & epoxy resin insulation.	17
Vacuum interrupter & solid polymer insulation.	37

Figure 6-48: Recloser age profile in years

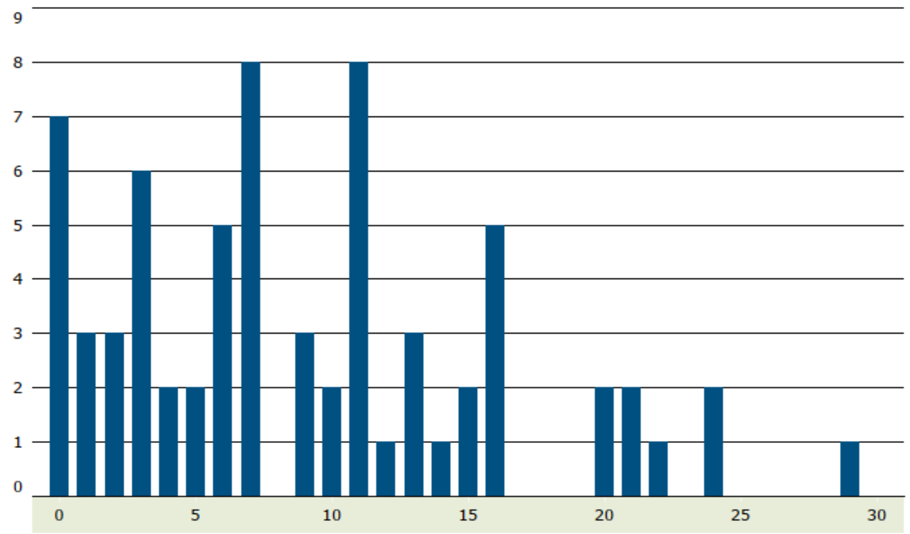
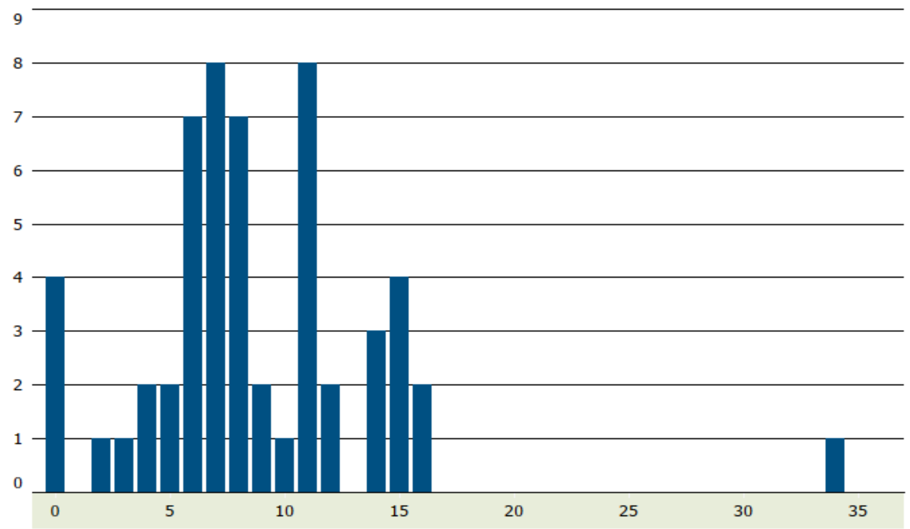


Figure 6-49: Recloser controller age profile in years



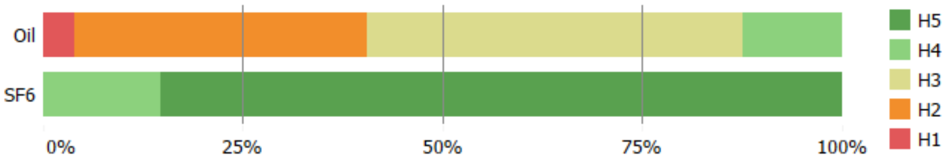
6.7.4 CONDITION, PERFORMANCE AND RISKS

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 the 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 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[60] asset health profile for our RMUs are shown in Figure 6-50.

Figure 6-50: RMU asset health as at 2021



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 designs account 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.

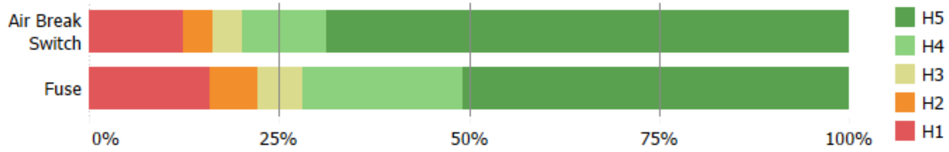
6.7.4.2 POLE MOUNTED FUSES AND SWITCHES

Overall, our pole mounted switches are in good condition, and the asset health profile is shown in Figure 6-51. 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.

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

Figure 6-51: Pole mounted fuse and switch asset health as at 2021



6.7.4.3 CIRCUIT BREAKERS, RECLOSERS AND SECTIONALISERS

The aged based[61] asset health profile for reclosers are shown in Figure 6-52. 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 1-2 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-year 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-year maintenance cycles.

Figure 6-52: Recloser asset health as at 2021

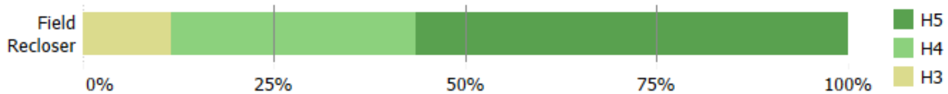
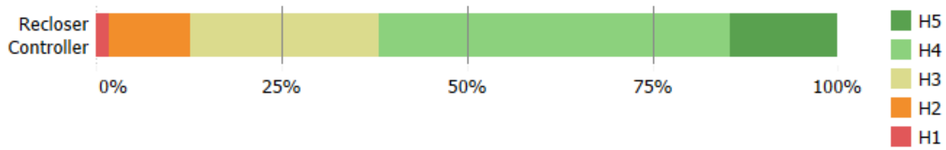


Figure 6-53: Recloser controller asset health as at 2021



The third oldest units were installed between 2005 and 2013. There are 17 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. Yet another drawback of these units is that the warranty on their control units is ten years and that spares are no longer available for these obsolete control units. Although a modified

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

backward compatible controller can be procured, a controller from an alternative, more reliable supplier cannot be used. We plan to replace these reclosers units 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 recloser 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-year 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 so that they can be bypassed if maintenance is required. This ensures that maintenance activities can be undertaken without any power outages.

Our design philosophy for 11 kV pole mounted reclosers is that they must be able to be bypassed by an air break switch (ABS) or disconnector to allow supply to be maintained during maintenance of the 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 twenty to thirty years ago,
- Third-party schedules such as units on industrial processing sites where production is affected.

However, we are making good progress with our program to access and maintain or replace these units based on their condition.

These devices are normally operated by hand, with more modern versions having the capability to be remotely controlled. All enclosures are locked and always secured. Our lock replacement program that started four years ago and was completed in 2020, 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 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 46 (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 contain at least one RMU. We also 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 considered, particularly with concerns of the electronic components such as the controller and automation equipment. After reaching a certain age, usually considered to be 10 years, electronic equipment can fail unexpectedly due to the aging of components such as capacitors. Batteries are also replaced based upon age, usually after five years from the date of manufacture. We will be replacing three reclosers on our network within the planning period, based on the AHI score of the asset.

All RMUs in our underground substations will be replaced as part of the underground substation replacement program. The budgets for these replacements are combined with the distribution transformer replacement budget forecast as detailed in Table 6-44.

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 Terminal 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 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, radio (UHF, VHF and 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 VHF, mobile, portable and fixed radio units with hilltop repeater sites that are connected via UHF trunk radio links to our Control Centre.

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 6-47.

Table 6-47: 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 several 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 6-48 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.

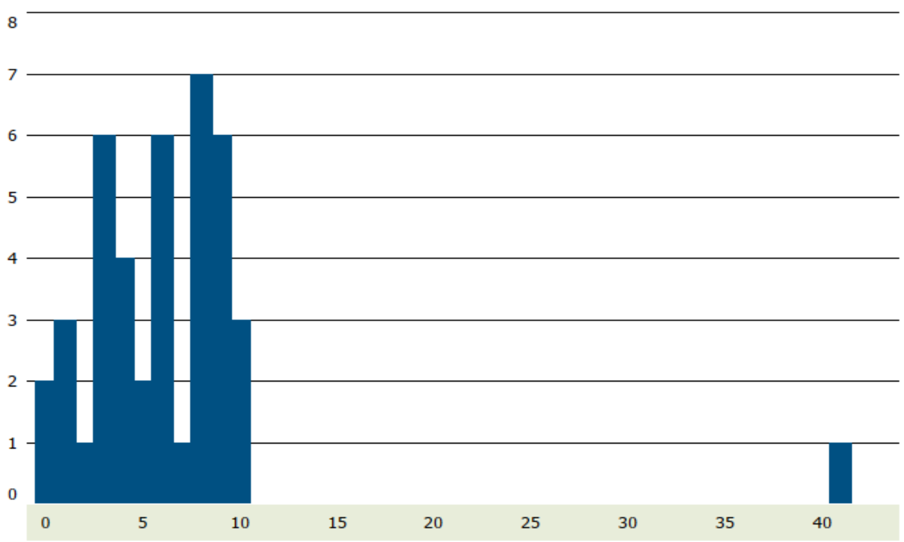
Table 6-48: RTU population by type at 31 March 2021

Type	RTUs	% of Total
Modern	39	93%
Legacy	3	7%
Total	**42**	**100%**

At the end of our replacement programme, we will have the SCADA network standardised on the industry standard DNP3 protocol. 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.

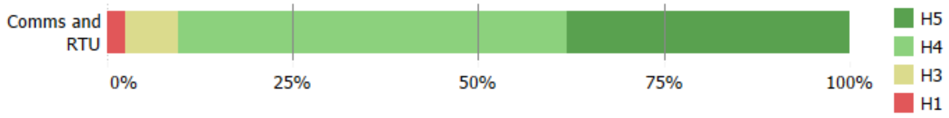
Figure 6-54: Zone substation SCADA and communications age profile



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 age based asset health of our RTUs are shown in Figure 6-55.

Figure 6-55: RTU asset health as at 2020



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 a cyber-attack; or 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 several 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 most 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 6-49: 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. 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 are 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 in SCADA and communications renewals to cater for the 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, load growth, or improvement on security of supply. These projects are either already underway or are to be started in the first half of the planning period. We have defined material projects as those projects where:

- The expenditure is more than $300 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

Table 6-50: Material replacement and renewal projects

Project type	Description	Estimated cost	Timing
Overhead line renewal/replacement projects (see Table 6-11).	These projects will replace and renew more than 350 kilometres of overhead lines (or 4700 poles) across our network.	$6.38 M	2022/23
Twizel Village zone substation rebuild.	This project will comprise the replacement of all the 33 kV and 11 kV switchgear as well as new protection as well as the re-location of the existing power transformer.	$2.6 M	2022/24
Underground substation replacement.	We will be replacing 3 or 4 underground substations per annum until we have the remaining 28 replaced.	$1.2 M	Annual
Protection upgrade.	Replace all the protection relays at Clandeboye #2 zone substation.	$350 k	2025/26
Switchgear replacement.	Replace the Hunt Street switching station switchgear. Only breaker trucks to be replaced.	$400 k	2025/26

6.10 NON-MATERIAL PROJECTS

This section summarised the non-material projects that do 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.	$1.2 m
Project timing.	2022/23
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.	$200 k

Project timing	Annual
In the Timaru CBD area many low voltage supply cables are in the footpaths with distribution and link boxes underground. This older type of 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 from 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.	$940 k
Project timing.	Annual
Over and above the material overhead line projects listed in the previous section, there are additional smaller overhead line replacement and renewal projects across our network. These range from red tag pole replacements to short sections of overhead line rebuilds. Budgets vary depending on the scale of the projects.	

7 / Asset Management Capability

7. ASSET MANAGEMENT CAPABILITY

This chapter describes our asset management capability as a set of subjects that ensures assets are managed over their lifecycle in accordance with 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.

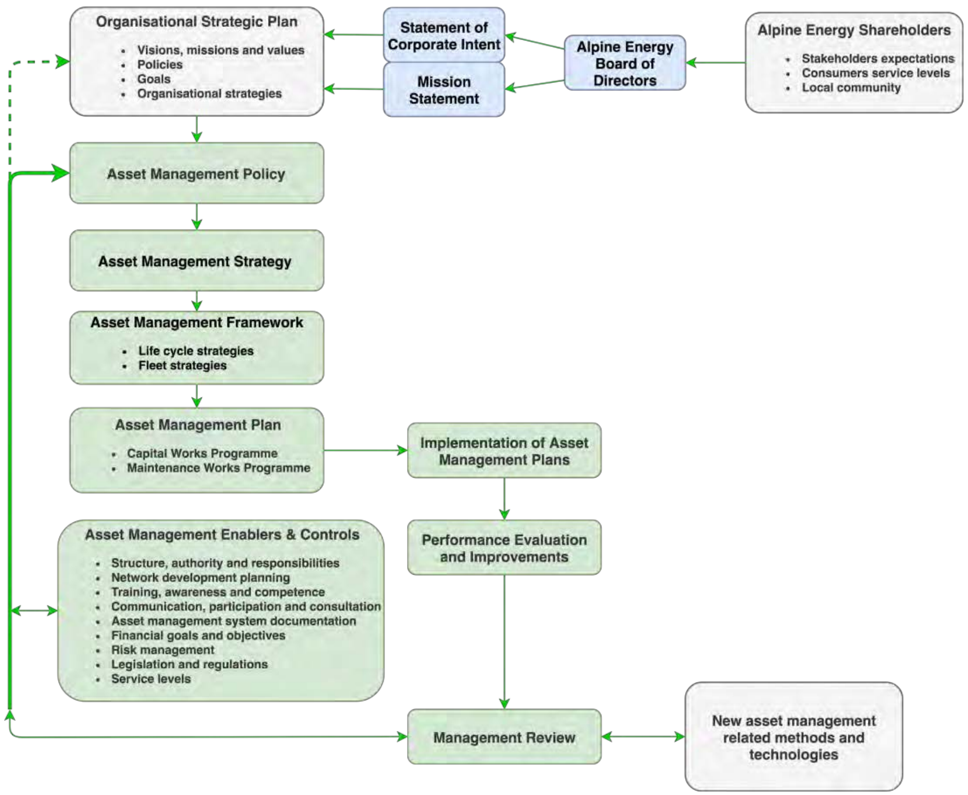
An Asset Management System (AMS) is a subset of asset management and is defined as a set of interrelated or interacting elements of an organisation for coordinating activity to realise value from assets.

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 to obtain certification. This framework and the journey are detailed in section 2.5. 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, and
- 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 ninety in 2021. 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 have split asset management functions from service delivery functions as detailed in section 2.6.2. This has enables us to ensure an increased focus on asset management and technological disruption in the industry.

In order to complete the CAPEX works plan, we also engage consultants and external contractors to ensure market related pricing is obtained for all our work.

7.3 INFORMATION SYSTEMS AND DATA

We are in the process of upgrading, replacing, and securing a few our information technology systems (IT), which are integral to our AMS. Our EAM (Enterprise Asset Management) system went live through the middle of 2017, and we implemented a major upgrade of that system in 2021 to bring additional functionality and to better meet the needs of users. We are also progressing through a major upgrade to our GIS system for the same reasons. Overall, there has been a focus on integration, automation, and mobility throughout the past few years and this will continue to be a focus as our systems become more capable of supporting those endeavours. We are also building up our internal resources to better support these underlying systems and meet user requirements.

Data quality and reporting have been increasing in the past years through data warehousing, a companywide reporting platform (Tableau) and data integrity initiatives. We are continuing to invest in these areas both in terms of systems and people.

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. There are, however, several additional asset management functionalities that we have implemented in subsequent stages and we continue to review additional functionalities that might be useful in 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. Updates from our service providers to the information contained in OneEnergy is now done through digital forms to allow data capture in the field and automated data checking where possible.

Information that prior to OneEnergy was available, but not always in the most appropriate format or location that allowed for easy or automatic extraction, has been moved to our new system. Since the implementation of OneEnergy, we have been reviewing and improving asset data continuously. Through an audit process and individual user efforts, both proactive and reactive, we continue to improve the quality and quantity of data on individual assets where issues are found.

We have embarked on 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. 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.

7.3.2 BUSINESS PROCESS MAPPING

The move to CiA in the OneEnergy EAM solution allows us the opportunity to revisit our existing business processes due to the additional capabilities of the inbuilt workflow. Our initial focus is on the work proposal and work as-built processes, however we will continue to review additional improvement initiatives and refinements as the new system is embedded in the organisation.

7.3.3 GEOSPATIAL INFORMATION SYSTEM

Our bespoke geospatial information system (GIS) was replaced in 2017 with ESRI's ArcGIS and ArcFM configuration model and tools. 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.

Integration between our GIS system and our EAM system is well established and continues to increase in scope as we improve our work flows. This is particularly evident in the mobility space as we leverage the GIS systems inherent capability and toolset to streamline and secure the flow of asset data from the field to the back office systems. We are investigating the ability and benefits of integrating our GIS and SCADA systems, and specifically utilise the outage management (OMS) module to improve our outage reporting and communications.

Our current area of focus is a migration to the latest version of ESRI and ArcFM; and our migration to the latest version of ESRI and ArcFM is almost complete. This has been a significant effort due to the underlying architectural differences between the versions. When complete, it will provide a large range of additional capabilities to improve our workflows and data visibility and ensure long-term vendor support.

7.3.4 SUPERVISORY CONTROL AND DATA ACQUISITION SYSTEM

Our 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 our contractors (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 have and are developing a series of views further 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 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 installed a new Drawing Management System (ADEPT) in response to the need for improved control and access to our Network drawings. All drawings are now stored and updated in a secure auditable manner, while workflows have been implemented to manage the update process. Post the initial implementation, a two-year project has now moved all the remaining paper-based drawings to an electronic format within ADEPT. All staff within our company and our major contractors 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.

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
- 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

Our next area of focus is on integration between our CAD activities and GIS. The intention is to remove duplication of activities, improve efficiency, modernise our CAD processes and provide better information on our CAD drawings. Additionally, we will be continuing to explore new areas of integration and additional ways of leveraging our existing integrations.

7.4 NON-NETWORK ASSETS

7.4.1 DRONE TECHNOLOGY

We continue to collaborate with like-minded energy companies to progress visual line of sight (VLOS) and beyond visual line of sight (BVLOS) development using drone technology.

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. We have undertaken a few trials to investigate network outages and to inspect the network is difficult to access terrain. A clear benefit is the reduced time and resulting costs to find faults or network damage.

7.4.2 RADIO MESH

Advanced meter deployment continues with well more than 90% 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 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 investigating to utilise this for network benefits.

7.4.3 PROPERTY

We own substation buildings, office and administration buildings and operational buildings. We relocated to a new, purpose-built, head office in 2018, facilitating a modern workplace environment.

Stage two of the development which is budgeted for the financial year 2021/22 is the optimisation of the Washdyke yard. This will include appropriate storage and management of network equipment spares, vehicle storage and traffic management and maximisation of our real estate footprint. We have further invested in key strategic land investments to secure the footprint for future network expansions.

7.4.4 DIGITAL SERVICES OVERVIEW AND STRATEGY

Digital Services cover all technology infrastructure, technology hardware assets, systems, applications, and interfaces at our company. Our recent Digital Strategy has been laid out over three horizons which will establish our digital foundations, enable our business and key workflows and eventually deliver digital as a way of working. Six key digital enablers have been identified as part of the Digital Strategy:

1. Performance improvement - Prioritised & aligned business initiatives focused on improving service delivery and operations.
2. Data - Structured, accurate and timely data to proactively and reactively manage and run operations e.g. analytics, insights, reporting and predictive asset management.
3. Partner and customer engagement - Establish new partnerships and enhance existing partnerships in the EDB, utilities and critical infrastructure industries.
4. Robust and reliable IT and OT foundations - Leading core systems and processes to reduce outages; deployed with infrastructure and tools to work flexibly.
5. Digital organisation and talent - Provide the tools, equipment and systems that will retain and attract a digital literate workforce.
6. Cyber security and resilience - Defence-in-depth approach across IT and OT environments utilising proven tools, methodologies, and partners.

A prioritised roadmap across three horizons has been developed which will direct us towards our strategic goals and is summarised in Table 7-1.

Table 7-1: Digital services prioritised roadmap

Horizon 1 'Establishing our foundations"	Horizon 2 'Enabling key processes'	Horizon 3 'Digital-as-a-way of working'
• Establish digital direction, resourcing, roadmap processes and governance. • Ensure core foundations are in place – systems, key processes, data, cyber security, infrastructure and business continuity. • Deliver 'quick wins' to build momentum.	• Focus on uplifting key business processes via optimisation and automation. • Build out our digital capability and leverage partnerships. • Innovation and prototyping is a way of working.	• Cross-functional teams who are digitally fluent. • Data is used to provide insights and support business decisions. • All key digital initiatives are up and running and are adding value to the business.

7.4.5 DIGITAL SERVICES SYSTEMS LANDSCAPE AND CORE SYSTEMS OVERVIEW

Table 7-2 details the various core systems used across the three main areas of our business.

Table 7-2: Digital services systems overview

Asset Management & Network Operations	Customer & Regulatory	Business Support
• Esri GEMA (GIS), ArcGIS, ArcGIS Workforce & ArcFM • AutoCAD & Adept • ETAP • Technology One • Survalent • TVD Avalanche • Tableau • FME	• Technology One • Axos • K2 • FME • Tableau • Microsoft 365	• Technology One • Microsoft 365 • Vault • Tableau • MYOB • Diligent

Since 2017, we have been using the TechnologyOne OneEnergy (T1) ERP solution for our Asset Management and Finance processes as well as workforce timesheets.

We are the leading NZ user of Survalent for our Supervisory Control & Data Acquisition (SCADA).

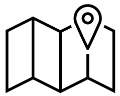
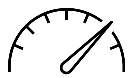
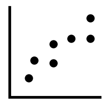
We also use the Esri suite of applications including GEMA Enterprise and ArcGIS as our GIS solution with FME acting as a core integration layer for our GIS operations.

All client billing is done via Axos, Vault is used for incident investigation, hazards and training and we have recently migrated our workforce onto Microsoft 365.

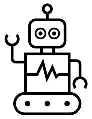
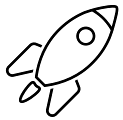
7.4.6 DIGITAL SERVICES TRENDS

We have identified examples of how some of the key technology trends in the power and utilities sector can be considered in relation to our Digital Strategy. This is depicted in Figure 7-2.

Figure 7-2: Key technology trends

Predictive Maintenance	Optimal Reliability	Data Analytics & Reporting
		
Establish the use of AI, and machine learning to catalogue	Ensure that Alpine adopt cutting edge distributed energy systems	Implement a fit-for-purpose data strategy which will provide

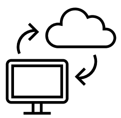
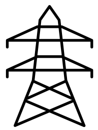
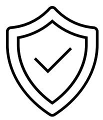
Alpine's assets and predict when they need to be maintained.	and processes to reduce outages and improve reliability.	derived data and insights to assist in future network planning.

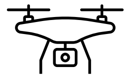
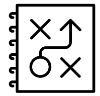
Improved Efficiencies	**Innovation As Standard**
	
Identify manual processes to utilise Robotic Process Automation (RPA) and allow employees to focus on more complex, higher-value tasks.	Position Alpine as a digital innovator who partner with leading exponents of new energy technologies.

7.4.7 PLANNED DIGITAL SERVICES INVESTMENTS

For the period covered by our digital strategy, we are planning investment in the following digital initiatives, as depicted in Figure 7-3.

Figure 7-3: Digital services investment areas

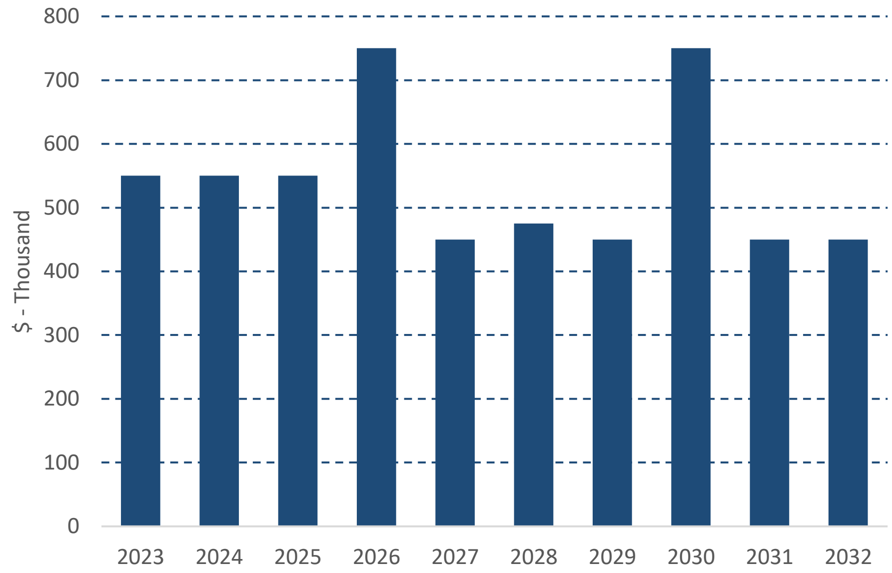
Core System Cloud Migrations	**ADMS, OMS & DERMS**	**Cyber Security**
		
Technology One (T1) have announced that they will cease to support on-premise versions of their product by 2024 and will not upgrade on-premise versions after 2022. Alpine are investigating the cloud migration journey for T1 and our other core on-premise systems e.g. GIS, ETAP, Adept.	Alpine have identified the need for new solutions to serve as the nerve centre to help manage the rapidly changing operating conditions on our network. Fit-for-purpose ADMS (Advanced Distribution Management System), OMS (Outage Management System) and DERMS (Distributed Energy Resources Management System) are planned to be implemented in the next few years.	Alpine is in the process of implementing a detailed cyber security investment roadmap which adheres to key security principles. Our principles include having a strong identity foundation, protecting data in transit and at rest, keeping people away from data, applying security at all layers, mechanising security practices, ensuring traceability and preparing for security events.

Innovation	**Data Strategy**
	
Alpine have been collaborating with our key industry partners and managed service providers to work on several Proof of Concepts that aim to deliver innovation in our key operational areas. Areas of interest include the use of drones and machine learning to provide greater visibility of our network assets and the use of RPA to remove manual time consuming processes.	Identifying and utilising the relevant data required to deliver on future business strategies and changing network demand is a challenge that all utility companies are facing globally. Alpine have commenced work on a data strategy which will focus on what value the data we generate provide and confirming the data and insights that Alpine requires or wants.

7.4.8 PLANNED DIGITAL SERVICES SPEND

We have estimated the following planned Digital Services Spend during the period covered by the Digital Strategy:

Figure 7-4: Digital services investment forecast



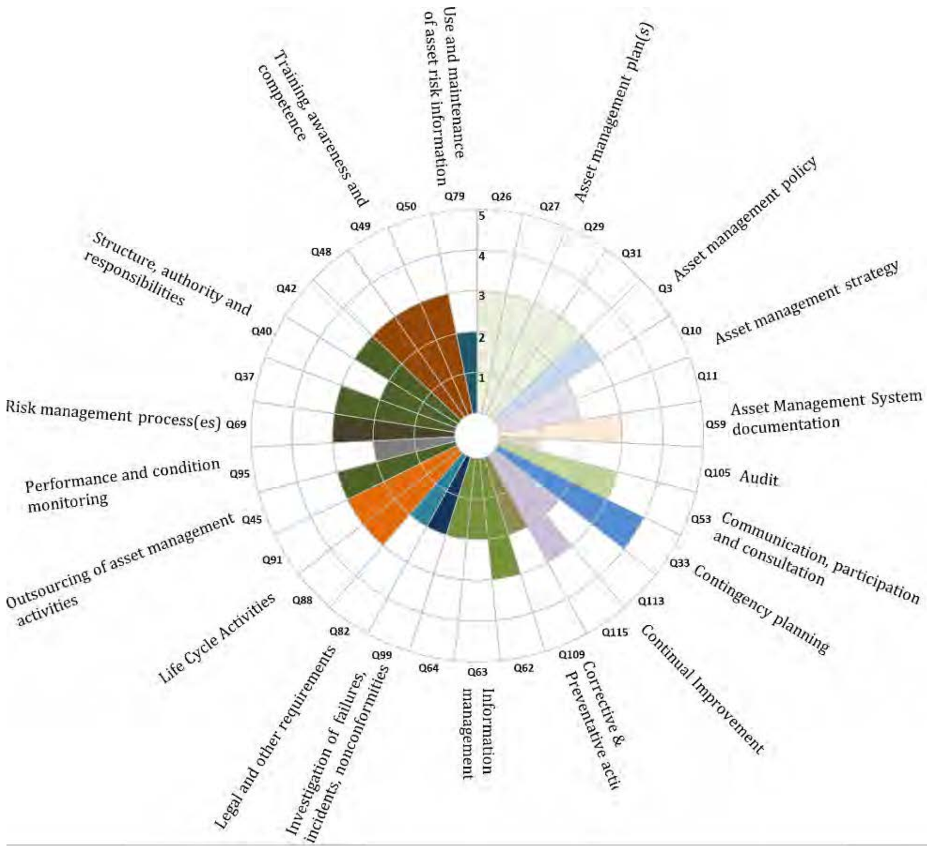
7.5 ASSET MANAGEMENT IMPROVEMENT INITIATIVES

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 7-5 gives a summary of our current AMMAT (Asset Management Maturity Assessment Tool) scores. The scores in Figure 7-5 are defined as follows:

- Maturity score = 0 means the elements required by PAS 55 are not in place
- Maturity score = 1 means the organisation has a basic understanding of the requirements of PAS55 and are planning to or have started to implement them
- Maturity score = 2 means the organisation has a good understanding of PAS 55 and work is progressing on implementing these
- Maturity score 3 means all elements of PAS 55 are integrated, only minor inconsistencies exist
- Maturity score 4 means the organisation used processes and approaches that go beyond the requirements of PAS 55.

Figure 7-5: 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 7-3.

Table 7-3 AMMAT scores that have improved

Asset Management Function	Improvement Identified
Asset management plans.	We upgraded our EAM system so that it can be accessed via a web browser rather than an application. This upgrade streamlined the accessibility of our EAM system from remote locations and provided a consistent look and feel. The upgraded EAM system provides a BI (Business Intelligence) platform that assists us with asset management analytics.

Asset Management Function	Improvement Identified
Communication, participation and consultation.	We have recently introduced a new internal intranet service to allow Mini Business Units (MBUs) to collaborate and share progress on shared goals, ultimately improving internal communications.
Outsourcing of asset management activities.	We have begun utilising the expertise of multiple contractors to deliver asset growth, new connection, and replacement projects within our network. This has allowed us to ensure industry aligned costs for network projects and reduced reliance on a single provider.
Investigation of failures, incidents and nonconformities.	We have introduced the need for an investigation into each asset defect to be performed. These investigations ultimately result in a documented specification of the defect(s) as inspected, and the works required to repair.
Life cycle activities.	Issues identified with network assets (or defects) now have a streamlined process to resolve from asset investigation, specification through to delivery. This has enabled documentation throughout all stages of a defect to track progress. We have identified the need to shift Asset Health Indicators to condition derived models and have begun by evaluating AHIs for our poles through existing pole tagging on inspection results.
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 Engineering NZ, Cigre, IEC, IEEE etc. Biannual development reviews are structured to identify personal development and training required for individual growth.
Structure & training.	We continued our Master Services Agreement with our incumbent contractor Netcon. This is also based on rate cards for most work types and scopes. Our people & Culture team plans for all training identified during the bi-annual staff development reviews.

7.5.2 FUTURE INITIATIVES

We have also identified improvement measures that would lift our scores in areas of greatest importance for our business. These are detailed in Table 7-4.

Table 7-4 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. Continue to develop fleet strategies. Communicate fleet strategies with stakeholders.	12 months 12 months 12 months
Asset management plan(s).	Complete fleet strategies for all asset types. Support MBU process and add asset management KPIs to boards. Measure effectiveness of the MBU communications.	12 months 12 Months Continuous
Contingency planning.	Test a system that deploys the emergency management teams as two separate pandemically isolated “bubbles.	12 months
Structure, authority, and responsibilities.	Develop procedures that streamline the workflow between different MBUs. Develop a resource strategy. Continue to support MBU communications and formalise throughout the organisation.	12 months 12 months 3 monthly
Structure, authority, and responsibilities.	Develop a resource strategy.	12 months
Communication, participation, and consultation.	Review and improve the MBU communications continually throughout the organisation.	Ongoing
Risk management process(es).	Develop new asset criticality assessment models.	Ongoing
Audit.	Develop an audit plan for our AMS.	Two years

8 / **Financial Summary**

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 2021. We have assumed a price inflator of 4.5% for 2023, 2.5% for 2024, and 2.0% for the other years 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 2020/21 financial year.

Table 8-1 Variance between actual and forecast expenditure in 2020/21

Expenditure type	Forecast ($'000)	Actual ($'000)	Variance (%)
Capital Expenditure.			
Consumer connection.	2,000	5,343	167%
System growth.	1,557	240	(85%)
Asset replacement & renewal.	10,992	10,881	(1%)
Asset relocations.	620	1,606	159%
Reliability, safety and environment.	1,415	902	(36%)
Subtotal network CAPEX.	16,584	18,972	14%
Operating Expenditure.			
Service interruptions & emergencies.	2,142	2,328	9%
Vegetation management.	849	742	(13%)
Routine & corrective maintenance & inspections.	2,754	2,765	0.4%
Asset replacement & renewal.	714	285	(60%)
Subtotal network OPEX.	6,459	6,120	(5%)
Total expenditure on network assets.	**23,043**	**25,092**	**+9%**

Information required by Clause 2.6.5 and Attachment A of the Information Disclosure Determination 2012 is 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 over budget mainly due to consumer connections expenditure, exceeding our planned budget by 167%. This expenditure realises a capital contribution in most instances. 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 36% which was due to an under-expenditure against the budget to install new reclosers to improve reliability of supply. The under expenditure in the capex growth category was because of lower than expected load growth in certain areas resulting in two voltage regulation, and three minor overhead line upgrade projects not going ahead. In addition, the Studholme ripple plant coupling cell upgrade was deferred to coincide with Transpower upgrading the GXP transformers.

Our overall OPEX on the network was over budget by 9%, which is largely due to a 9% overspend in service interruptions and emergencies.

8.2 EXPENDITURE FORECASTS

8.2.1 CAPEX

Our current forecast for total network CAPEX for the planning period is given in Figure 8-1 and 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 4.5% for 2023, 2.5% for 2024, and 2.0% for the other years according to the most recent Treasury forecast. We have also adjusted our forecast based on increased shipping cost for equipment sourced overseas, higher commodity prices, and the higher wage inflation numbers.

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

Figure 8-1: Total CAPEX for the planning period

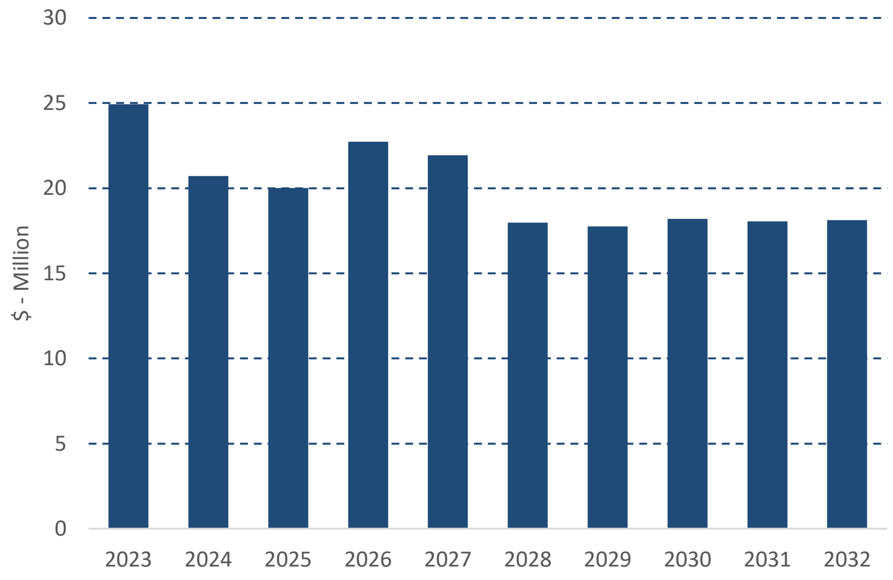


Table 8-2 Total CAPEX for the planning period

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
24,932	20,720	20,005	22,725	21,930	17,980	17,755	18,200	18,050	18,125

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. A key growth project in FY23 is due to Timaru Port's large growth and development which has provided a combination of additional connections and network capex work. Most of the arable farmland in South Canterbury that can be irrigated is now under irrigation, resulting in decreasing irrigation load growth. 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

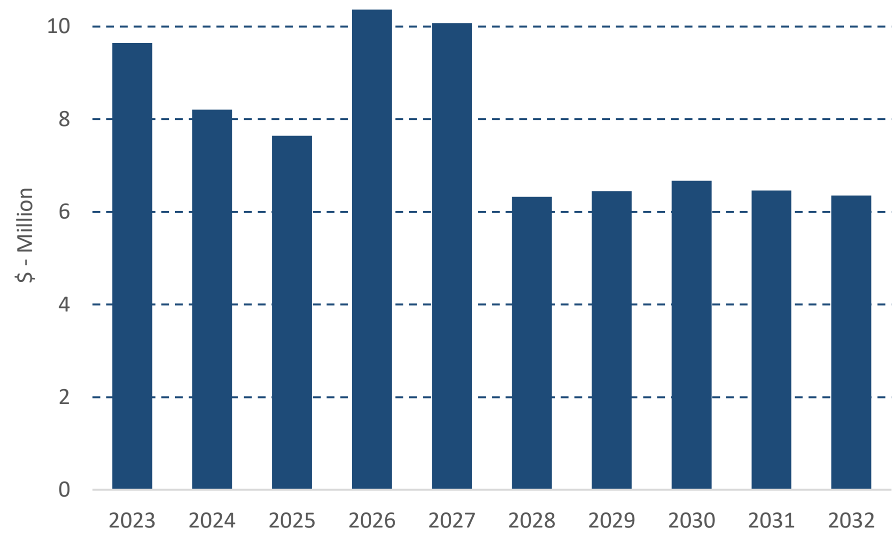


Table 8-3 Network development CAPEX for the planning period

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
9.65	8.21	7.64	10.37	10.08	6.33	6.45	6.67	6.46	6.36

The largest expenditure for the next 3 years in network development CAPEX is a result 33kV network upgrades and typical underground installs required for network growth.

8.2.1.2 FLEET CAPEX

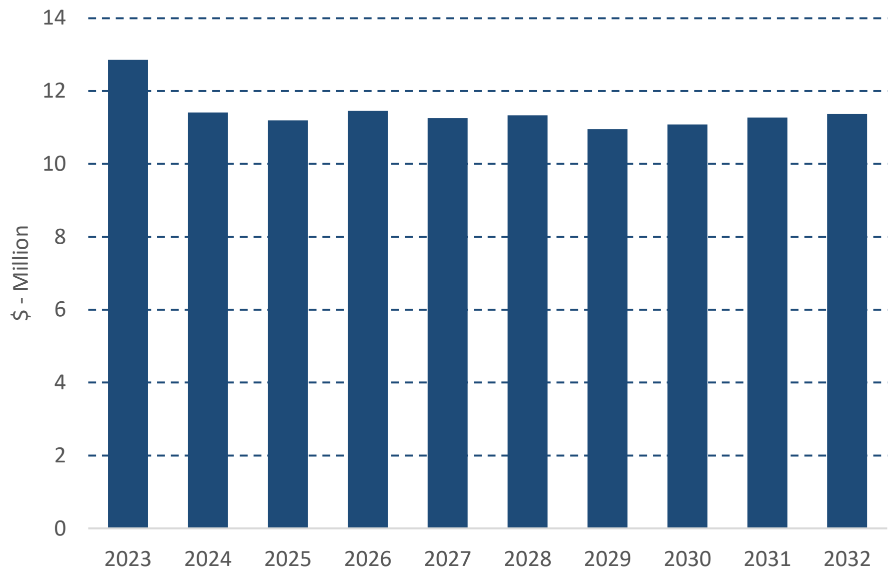
Our fleet CAPEX includes expenditure on all our asset fleets namely:

- 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 relocation of our Twizel zone substation in 2022/23, and the replacement of our Tekapo zone substation switchboard in 2028/9.

Table 8-4 Fleet management CAPEX for the planning period

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
12.86	11.41	11.20	11.46	11.26	11.34	10.96	11.08	11.27	11.37

8.2.1.3 NON-NETWORK CAPEX

Our non-network capex shows significant expenditure in the first year. This is mainly made up of the projects as detailed in Table 8-5.

Table 8-5 Non-network CAPEX projects for 2022/23

Project / Initiative	Budget ($)
IT	1,050 k
Vehicles	350 k
Alpine House Building Investment	1,000 k

Non-network capex for the planning period is given in Figure 8-4 and Table 8-6 below.

Figure 8-4: Non-network CAPEX for the planning period

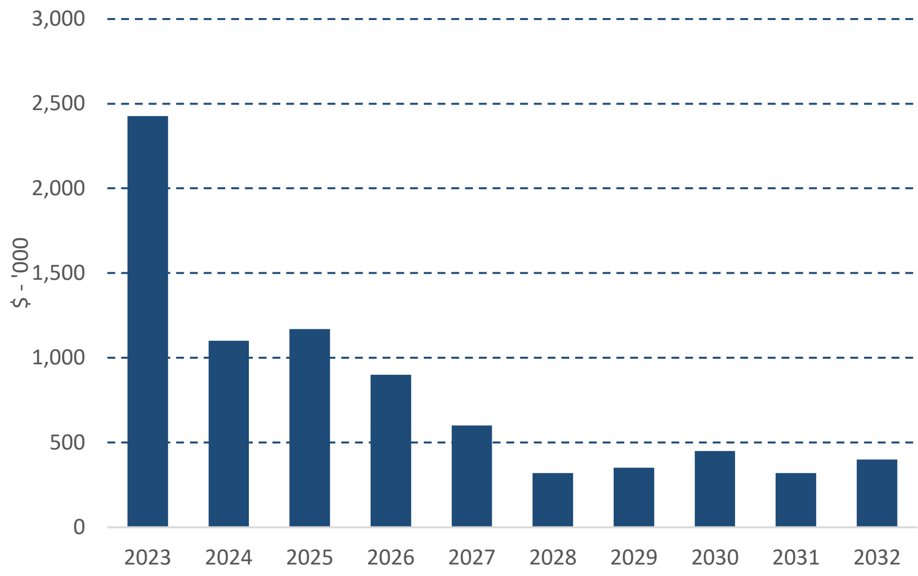


Table 8-6 Non-network CAPEX for the planning period

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
2.43	1.10	1.17	0.90	0.60	0.32	0.35	0.45	0.32	0.40

The IT infrastructure budget consist of:

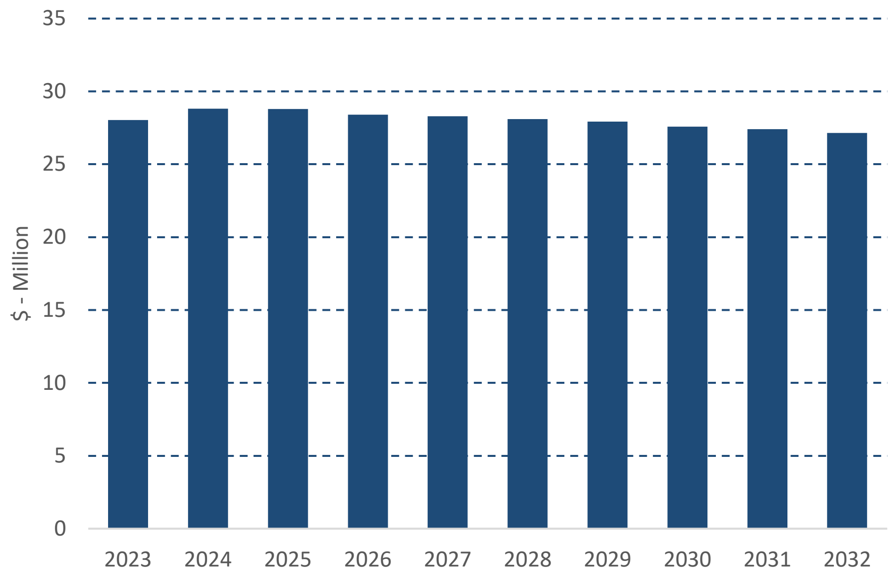
- software to formalise and structure our electronic workflow system.
- asset walkdown/audit project to verify and improve the quality of our asset data as migrated from our legacy systems into OneEnergy.

- implementing a detailed cyber security investment strategy to protect data, apply security at all layers and prepare for security events.

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



OPEX is increasing over the planning period. Where our forecast budgets for the remainder of DPP3 is in line with our allowances, we are forecasting a CPI increase for the DPP4 period.

Table 8-7 Total OPEX for the planning period

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
28.03	28.81	28.79	28.40	28.30	28.09	27.93	27.58	27.40	27.14

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.

We have managed to maintain our direct network OPEX at a constant level in constant terms for the planning period, unless intervention is required due to health and safety factors, or reliability forces us to re-evaluate.

Our forecast OPEX per asset categories is detailed in Table 8-9.

Figure 8-6: Direct network OPEX for the planning period

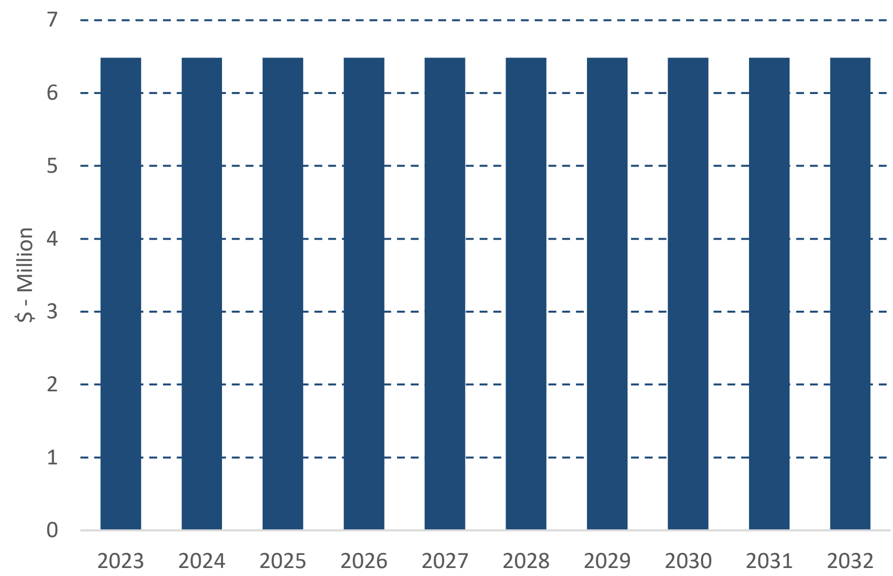


Table 8-8 Direct network OPEX for the planning period

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49

Table 8-9 OPEX per asset category

Asset Category	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LVLines & cable	0.32	0.32	0.32	0.31	0.31	0.31	0.31	0.31	0.31	0.31
DistSubs	1.30	1.30	1.29	1.29	1.29	1.28	1.28	1.27	1.27	1.26
Dist Line & Cable	4.33	4.34	4.34	4.35	4.36	4.36	4.37	4.38	4.38	4.39
Zone Subs	0.39	0.39	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Sub Transm.	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
SCADA	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12

8.2.2.2 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

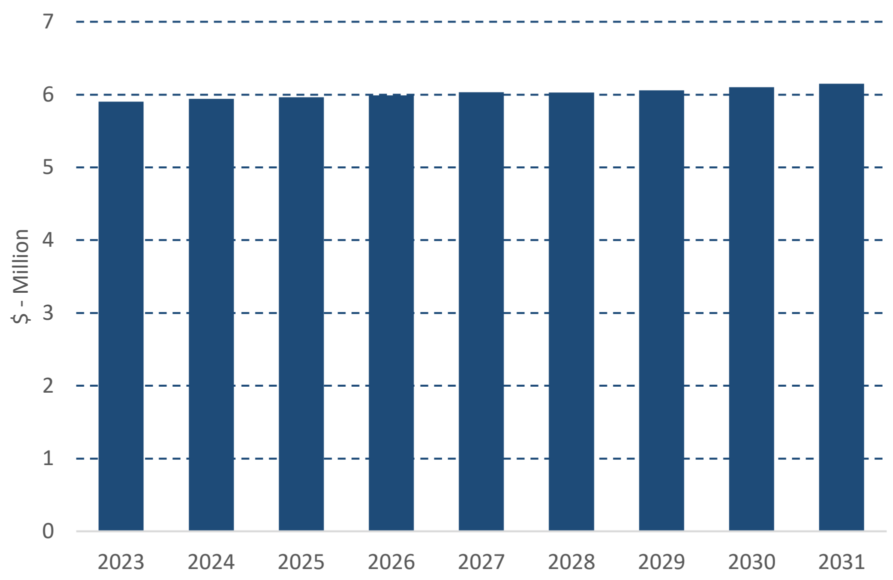


Table 8-10 SONS OPEX for the planning period

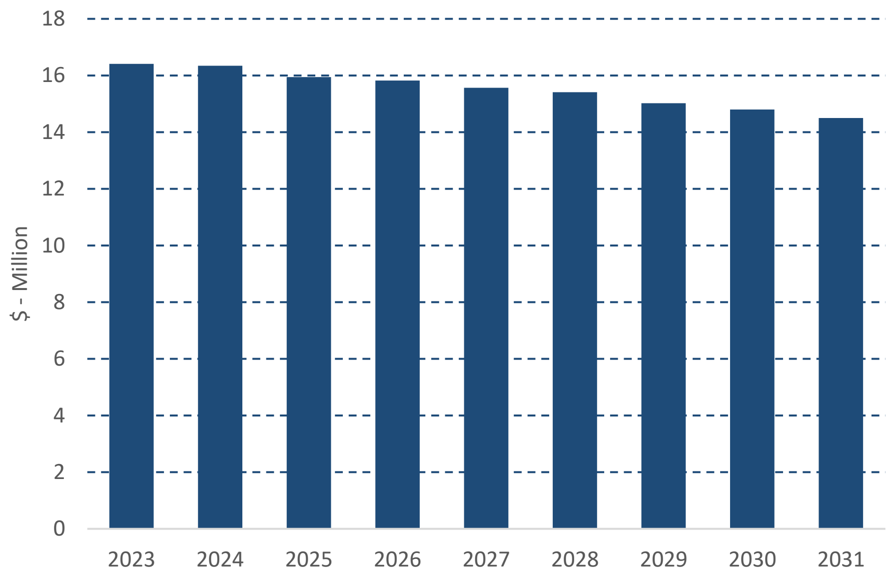
2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
6.07	5.91	5.95	5.97	5.99	6.04	6.03	6.06	6.11	6.16

This expenditure category has an initial uplift from last year. The additional expenditure is mainly because of increased cost to process and evaluate a significant increase in distributed generation applications of scale, as well as the significant increase in wage inflation. In nominal terms there will be an increasing trend due to CPI adjustments as detailed in the schedule 14a) in Appendix A2.8. Any changes for additional regulatory reporting requirements will not be material.

8.2.2.3 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.

There is an increase in our non-network OPEX in line with our strategic objectives to transform our company as detailed in section 2.2.

Table 8-11 Business Support OPEX for the planning period

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
15.49	16.42	16.36	15.95	15.83	15.57	15.42	15.03	14.81	14.50

8.3 PLANNING PERIOD EXPENDITURE FORECAST

Table 8-12 Total expenditure for the planning period 2022 to 2032 ('000)

Expenditure Category	Actual	Forecast										
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Capital expenditure												
Customer connections	5,343	2,400	4,400	4,500	4,400	3,100	3,300	3,300	3,400	3,450	3,490	3,535
Growth	240	2,921	2870	625	1570	5370	5170	820	1120	1920	1720	1720
Replacements & Renewal	10,881	10,297	12,855	11,410	11,195	11,455	11,255	11,335	10,955	11,080	11,270	11,370
Relocations	1,606	500	1400	2110	1000	1000	1000	1625	1000	850	800	730
Reliability, safety & environment	902	1,210	980	975	670	900	605	580	930	450	450	370
Subtotal – Network CAPEX	**18,972**	**17,328**	**22,505**	**19,620**	**18,835**	**21,825**	**21,330**	**17,660**	**17,405**	**17,750**	**17,730**	**17,725**
Non-network CAPEX	564	750	2,427	1,100	1,170	900	600	320	350	450	320	400
TOTAL CAPEX	**19,536**	**18,078**	**24,932**	**20,720**	**20,005**	**22,725**	**21,930**	**17,980**	**17,755**	**18,200**	**18,050**	**18,125**
Operational expenditure												
Service interruptions & emergencies	2,441	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045
Vegetation	621	820	820	820	820	820	820	820	820	820	820	820
Routine maintenance	3,515	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330
Replacement & renewal	203	290	290	290	290	290	290	290	290	290	290	290
Subtotal – Network OPEX	**6,780**	**6,485**	**6,485**	**6,485**	**6,485**	**6,485**	**6,485**	**6,485**	**6,485**	**6,485**	**6,485**	**6,485**
Non-network OPEX	13,837	13,925	21,545	22,320	22,300	21,915	21,815	21,600	21,445	21,090	20,910	20,650
TOTAL OPEX	**20,617**	**20,410**	**28,030**	**28,805**	**28,785**	**28,400**	**28,300**	**28,085**	**27,930**	**27,575**	**27,395**	**27,135**
Total expenditure on assets	**39,493**	**38,488**	**52,962**	**49,525**	**48,790**	**51,125**	**50,230**	**46,065**	**45,685**	**45,775**	**45,445**	**45,260**

9 / Appendices

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
EEA	—	Electrical Engineers Association

EC	—	Electricity Commission
EDB	—	NZ Electricity Distribution Businesses
EEA	—	Electricity Engineers' Association
EF	—	Earth Fault
ELT	—	Executive Leadership Team
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
MBU	—	Micro Business Unit
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
SMF	—	Safety Management Framework
SONS	—	System Operations and Network Support
STU	—	Studholme grid exit point
TDC	—	Timaru District Council
TDHL	—	Timaru District Holdings Limited
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
WDC	—	Waimate District Council
XLPE	—	Cross Linked Polyethylene Cable

A.2 Disclosure schedules

A.2.1 SCHEDULE 11A

Company Name	**Alpine Energy Ltd**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	2,400	4,598	4,820	4,807	3,455	3,751	3,826	4,021	4,162	4,294	4,436
11	System growth	2,921	2,999	669	1,715	5,984	5,877	951	1,325	2,316	2,116	2,159
12	Asset replacement and renewal	10,297	13,433	12,222	12,231	12,765	12,793	13,142	12,955	13,365	13,866	14,269
13	Asset relocations	500	1,463	2,260	1,093	1,114	1,137	1,884	1,183	1,025	984	916
14	Reliability, safety and environment:											
15	Quality of supply											
16	Legislative and regulatory											
17	Other reliability, safety and environment	1,210	1,024	1,044	732	1,003	688	672	1,100	543	554	464
18	**Total reliability, safety and environment**	1,210	1,024	1,044	732	1,003	688	672	1,100	543	554	464
19	**Expenditure on network assets**	17,328	23,517	21,015	20,578	24,321	24,246	20,475	20,584	21,411	21,814	22,244
20	Expenditure on non-network assets	730	2,536	1,178	1,278	1,003	682	371	414	543	394	502
21	**Expenditure on assets**	18,058	26,053	22,193	21,856	25,324	24,928	20,846	20,998	21,954	22,208	22,746
22												
23	*plus* Cost of financing											
24	*less* Value of capital contributions	2,400	4,180	4,392	4,370	3,009	3,296	3,362	3,548	3,679	3,802	3,934
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	15,658	21,873	17,801	17,486	22,315	21,632	17,484	17,450	18,275	18,406	18,812
28												
29	Assets commissioned	16,978	20,320	18,820	17,565	21,108	21,802	18,521	17,458	18,068	18,374	18,711
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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
32		**$000 (in constant prices)**										
33	Consumer connection	2,400	4,400	4,500	4,400	3,100	3,300	3,300	3,400	3,450	3,490	3,535
34	System growth	2,921	2,870	625	1,570	5,370	5,170	820	1,120	1,920	1,720	1,720
35	Asset replacement and renewal	10,297	12,855	11,410	11,195	11,455	11,255	11,335	10,955	11,080	11,270	11,370
36	Asset relocations	500	1,400	2,110	1,000	1,000	1,000	1,625	1,000	850	800	730
37	Reliability, safety and environment:											
38	Quality of supply	-	-	-	-	-	-					
39	Legislative and regulatory	-	-	-	-	-	-					
40	Other reliability, safety and environment	1,210	980	975	670	900	605	580	930	450	450	370
41	**Total reliability, safety and environment**	1,210	980	975	670	900	605	580	930	450	450	370
42	**Expenditure on network assets**	17,328	22,505	19,620	18,835	21,825	21,330	17,660	17,405	17,750	17,730	17,725
43	Expenditure on non-network assets	730	2,427	1,100	1,170	900	600	320	350	450	320	400
44	**Expenditure on assets**	18,058	24,932	20,720	20,005	22,725	21,930	17,980	17,755	18,200	18,050	18,125
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	500	1,400	2,110	1,000	1,000	1,000	1,625	1,000	850	800	730
49	Research and development											
50												

for year ended	Current Year CY 31 Mar 22	CY+1 31 Mar 23	CY+2 31 Mar 24	CY+3 31 Mar 25	CY+4 31 Mar 26	CY+5 31 Mar 27	CY+6 31 Mar 28	CY+7 31 Mar 29	CY+8 31 Mar 30	CY+9 31 Mar 31	CY+10 31 Mar 32
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	198	320	407	355	451	526	621	712	804	901
System growth	-	129	44	145	614	707	131	205	396	396	439
Asset replacement and renewal	-	578	812	1,036	1,310	1,538	1,807	2,000	2,285	2,596	2,899
Asset relocations	-	63	150	93	114	137	259	183	175	184	186
Reliability, safety and environment:											
Quality of supply	-	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	44	69	62	103	83	92	170	93	104	94
Total reliability, safety and environment	-	44	69	62	103	83	92	170	93	104	94
Expenditure on network assets	-	1,012	1,395	1,743	2,496	2,916	2,815	3,179	3,661	4,084	4,519
Expenditure on non-network assets	-	109	78	108	103	82	51	64	93	74	102
Expenditure on assets	-	1,121	1,473	1,851	2,599	2,998	2,866	3,243	3,754	4,158	4,621

11a(ii): Consumer Connection

for year ended	Current Year CY 31 Mar 22	CY+1 31 Mar 23	CY+2 31 Mar 24	CY+3 31 Mar 25	CY+4 31 Mar 26	CY+5 31 Mar 27
*Consumer types defined by EDB**	**$000 (in constant prices)**					
Low user charge	120	220	225	220	155	165
15	336	616	630	616	434	462
360	288	528	540	528	372	396
Assessed	552	1,012	1,035	1,012	713	759
TOU 400 V	1,104	2,024	2,070	2,024	1,426	1,518
**include additional rows if needed*						
Consumer connection expenditure	2,400	4,400	4,500	4,400	3,100	3,300
less Capital contributions funding consumer connection	2,000	3,600	3,700	3,600	2,300	2,500
Consumer connection less capital contributions	400	800	800	800	800	800

11a(iii): System Growth

	Current Year CY 31 Mar 22	CY+1 31 Mar 23	CY+2 31 Mar 24	CY+3 31 Mar 25	CY+4 31 Mar 26	CY+5 31 Mar 27
Subtransmission	-	-	-	-	-	-
Zone substations	1,201	-	-	450	4,750	4,000
Distribution and LV lines	-	-	-	-	-	-
Distribution and LV cables	1,300	450	500	1,000	300	1,050
Distribution substations and transformers	120	2,420	120	120	120	120
Distribution switchgear	150	-	-	-	-	-
Other network assets	150	-	5	-	200	-
System growth expenditure	2,921	2,870	625	1,570	5,370	5,170
less Capital contributions funding system growth	200	200	200	200	200	200
System growth less capital contributions	2,721	2,670	425	1,370	5,170	4,970

	for year ended	Current Year CY 31 Mar 22	CY+1 31 Mar 23	CY+2 31 Mar 24	CY+3 31 Mar 25	CY+4 31 Mar 26	CY+5 31 Mar 27
11a(iv): Asset Replacement and Renewal		**$000 (in constant prices)**					
Subtransmission		180	-	-	-	-	-
Zone substations		250	1,480	1,700	190	850	285
Distribution and LV lines		6,150	7,910	4,755	7,190	6,350	7,550
Distribution and LV cables		600	-	300	140	-	-
Distribution substations and transformers		1,950	1,490	2,010	2,160	2,010	2,010
Distribution switchgear		50	1,110	1,190	1,150	1,150	1,100
Other network assets		1,117	865	1,455	365	1,095	310
Asset replacement and renewal expenditure		10,297	12,855	11,410	11,195	11,455	11,255
less Capital contributions funding asset replacement and renewal		200	200	200	200	200	200
Asset replacement and renewal less capital contributions		10,097	12,655	11,210	10,995	11,255	11,055

	for year ended	Current Year CY 31 Mar 22	CY+1 31 Mar 23	CY+2 31 Mar 24	CY+3 31 Mar 25	CY+4 31 Mar 26	CY+5 31 Mar 27
11a(v): Asset Relocations							
*Project or programme**		**$000 (in constant prices)**					
Overhead to Underground conversions		500	1,400	2,110	1,000	1,000	1,000
[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 project or programmes - asset relocations							
Asset relocations expenditure		500	1,400	2,110	1,000	1,000	1,000
less Capital contributions funding asset relocations							
Asset relocations less capital contributions		500	1,400	2,110	1,000	1,000	1,000

	for year ended	Current Year CY 31 Mar 22	CY+1 31 Mar 23	CY+2 31 Mar 24	CY+3 31 Mar 25	CY+4 31 Mar 26	CY+5 31 Mar 27
11a(vi): Quality of Supply							
*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 - quality of supply							
Quality of supply expenditure		-	-	-	-	-	-
less Capital contributions funding quality of supply							
Quality of supply less capital contributions		-	-	-	-	-	-

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136		for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27

137 11a(vii): Legislative and Regulatory

		Project or programme*	$000 (in constant prices)					
139		[Description of material project or programme]						
140		[Description of material project or programme]						
141		[Description of material project or programme]						
142		[Description of material project or programme]						
143		[Description of material project or programme]						
144		*include additional rows if needed*						
145		All other projects or programmes - legislative and regulatory						
146		**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less*	Capital contributions funding legislative and regulatory						
148		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
150		for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27

151 11a(viii): Other Reliability, Safety and Environment

		Project or programme*	$000 (in constant prices)					
153		SCADA and Comms	615	410	605	270	500	180
154		Softwood pole replacement	210	160	160	160	160	160
155		Reclosers, automation & RMUs	310	260	210	210	210	235
156		Zone sub arc flash & ventilation	75	-	-	-	-	-
157		AMG Circuit Breaker	-	150	-	-	-	-
		Substation Security Video Monitoring	-	-	-	30	30	30
158		*include additional rows if needed*						
159		All other projects or programmes - other reliability, safety and environment						
160		**Other reliability, safety and environment expenditure**	1,210	980	975	670	900	605
161	*less*	Capital contributions funding other reliability, safety and environment						
162		**Other reliability, safety and environment less capital contributions**	1,210	980	975	670	900	605
163								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165		for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27

166 11a(ix): Non-Network Assets

167	**Routine expenditure**							
168		*Project or programme**	$000 (in constant prices)					
169		IT	500	1,050	1,000	1,000	750	500
170		Equipment	20	27	-	-	-	-
171		Vehicles	-	350	100	170	150	100
172		[Description of material project or programme]						
173		[Description of material project or programme]						
174		*include additional rows if needed*						
175		All other projects or programmes - routine expenditure						
176		**Routine expenditure**	520	1,427	1,100	1,170	900	600
177	**Atypical expenditure**							
178		*Project or programme**						
179		Property	210	1,000	-	-	-	-
180		[Description of material project or programme]						
181		[Description of material project or programme]						
182		[Description of material project or programme]						
183		[Description of material project or programme]						
184		*include additional rows if needed*						
185		All other projects or programmes - atypical expenditure						
186		**Atypical expenditure**	210	1,000	-	-	-	-
187								
188		**Expenditure on non-network assets**	730	2,427	1,100	1,170	900	600

A.2.2 SCHEDULE 11B

	Company Name	Alpine Energy Ltd
	AMP Planning Period	1 April 2022 – 31 March 2032

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 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	2,045	2,137	2,190	2,234	2,279	2,325	2,371	2,418	2,467	2,516	2,566
11	Vegetation management	820	857	878	896	914	932	951	970	989	1,009	1,029
12	Routine and corrective maintenance and inspection	3,330	3,480	3,567	3,638	3,711	3,785	3,861	3,938	4,017	4,097	4,179
13	Asset replacement and renewal	290	303	311	317	323	330	336	343	350	357	364
14	**Network Opex**	6,485	6,777	6,946	7,085	7,227	7,372	7,519	7,669	7,823	7,979	8,138
15	System operations and network support	4,886	6,333	6,324	6,495	6,648	6,807	6,994	7,130	7,307	7,509	7,720
16	Business support	9,038	16,179	17,580	17,864	17,769	17,985	18,049	18,227	18,130	18,214	18,196
17	**Non-network opex**	13,924	22,512	23,904	24,359	24,417	24,792	25,043	25,357	25,437	25,723	25,916
18	**Operational expenditure**	20,409	29,289	30,850	31,444	31,644	32,164	32,562	33,026	33,260	33,702	34,054

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 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045
23	Vegetation management	820	820	820	820	820	820	820	820	820	820	820
24	Routine and corrective maintenance and inspection	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330
25	Asset replacement and renewal	290	290	290	290	290	290	290	290	290	290	290
26	**Network Opex**	6,485	6,485	6,485	6,485	6,485	6,485	6,485	6,485	6,485	6,485	6,485
27	System operations and network support	4,886	6,060	5,904	5,945	5,966	5,989	6,032	6,029	6,057	6,103	6,151
28	Business support	9,038	15,482	16,413	16,351	15,945	15,822	15,567	15,413	15,030	14,803	14,499
29	**Non-network opex**	13,924	21,542	22,317	22,296	21,911	21,811	21,599	21,442	21,087	20,906	20,650
30	**Operational expenditure**	20,409	28,027	28,802	28,781	28,396	28,296	28,084	27,927	27,572	27,391	27,135
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	315	315	315	315	315	315	315	315	315	315	315

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 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	92	145	189	234	280	326	373	422	471	521
43	Vegetation management	-	37	58	76	94	112	131	150	169	189	209
44	Routine and corrective maintenance and inspection	-	150	237	308	381	455	531	608	687	767	849
45	Asset replacement and renewal	-	13	21	27	33	40	46	53	60	67	74
46	**Network Opex**	-	292	461	600	742	887	1,034	1,184	1,338	1,494	1,653
47	System operations and network support	-	273	420	550	682	818	962	1,101	1,250	1,406	1,569
48	Business support	-	697	1,167	1,513	1,824	2,163	2,482	2,814	3,100	3,411	3,697
49	**Non-network opex**	-	970	1,587	2,063	2,506	2,981	3,444	3,915	4,350	4,817	5,266
50	**Operational expenditure**	-	1,262	2,048	2,663	3,248	3,868	4,478	5,099	5,688	6,311	6,919

A.2.3 SCHEDULE 12A

Company Name	**Alpine Energy Ltd**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**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**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.43%	-	26.75%	38.30%	34.52%		3	0.50%
11	All	Overhead Line	Wood poles	No.	2.40%	10.90%	43.00%	17.90%	25.80%		3	3.00%
12	All	Overhead Line	Other pole types	No.							[Select one]	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	2.23%	31.05%	28.79%	37.93%		3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							[Select one]	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	0.10%	-	0.32%	3.93%	95.65%		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.		-	16.00%	32.00%	52.00%		3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							[Select one]	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.					100.00%		4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	5.00%	5.00%	16.00%	16.00%	58.00%		4	5.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.					100.00%		4	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	8.00%	24.00%	14.00%	6.00%	48.00%		3	5.00%
30	HV	Zone substation switchgear	33kV RMU	No.					100.00%		4	-
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.	4.82%		4.22%	19.28%	71.68%		3	5.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.				37.50%	62.50%		3	-
35												

	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
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.			26.92%	7.69%	65.39%		4	4.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.00%	35.00%	23.00%	13.00%	28.00%		3	2.00%
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	0.28%	0.36%	1.39%	5.49%	92.48%		3	0.50%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	0.04%	77.42%	22.54%		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.			9.09%	36.36%	54.55%		3	-
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.	14.00%	5.50%	5.20%	14.00%	61.30%		2	5.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	18.00%	27.00%	55.00%		3	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1.89%	20.05%	23.58%	15.33%	39.15%		3	2.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.89%	31.33%	21.93%	27.08%	18.77%		3	1.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.38%	12.23%	21.80%	37.82%	27.77%		3	1.00%
53	HV	Distribution Transformer	Voltage regulators	No.				11.76%	88.24%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.							[Select one]	
55	LV	LV Line	LV OH Conductor	km	23.09%	8.81%	44.43%	19.64%	4.03%		2	2.00%
56	LV	LV Cable	LV UG Cable	km	0.10%	3.07%	19.62%	45.37%	31.84%		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.	2.00%	-	7.00%	50.00%	41.00%		4	2.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	17.47%	13.25%	7.83%	4.22%	57.23%		2	5.00%
61	All	Capacitor Banks	Capacitors including controls	No.				47.06%	52.94%		3	-
62	All	Load Control	Centralised plant	Lot		13.50%	14.50%	13.00%	59.00%		3	16.00%
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km					100.00%		4	-

A.2.4 SCHEDULE 12B

Company Name **Alpine Energy Ltd**
AMP Planning Period **1 April 2022 – 31 March 2032**

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**

8	*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)	4.3		N		-	-	-	No constraint within +5 years	Meets Alpine security standard
10	Old Man Rage (OMR)	0.38		N		-	-	-	No constraint within +5 years	Balmoral sub decommissioned in 2019
11	Bells Pond (BPD)	15.05	20	N-1		75%	20	132%	Transformer	T1 installed FY18/19, T2 to be upgraded to provide N-1 security of supply
12	Clandeboye 1 (CD1)	13.96	20	N-1		70%	30	60%	Transformer	Upgrade transformers to restore N-1 security of supply
13	Clandeboye 2 (CD2)	20.07	25	N-1		80%	25	101%	No constraint within +5 years	Meets Alpine Security standard due to sufficient 11 kV backup
14	Cooney's Road (CNR)	4.64		N	1.8/0.8/0.6*	-	-	-	No constraint within +5 years	Meets Alpine security standard
15	Fairlie (FLE)	2.98		N		-	-	-	No constraint within +5 years	Meets Alpine security standard
16	Geraldine (GLD)	6.87		N		-	-	-	No constraint within +5 years	Meets Alpine security standard
17	Haldon Lilybank (HLB)	0.48		N		-	-	-	No constraint within +5 years	Meets Alpine security standard
18	Pareora (PAR)	9.68	15	N-1		65%	15	76%	No constraint within +5 years	Meets Alpine security standard
19	Pleasant Point (PLP)	4.96		N		-	-	-	No constraint within +5 years	Meets Alpine security standard
20	Rangitata (RGA)	10.64	10	N-1		106%	10	125%	Subtransmission circuit	Line capacity constraint, sufficient 11 kV backup in place
21	Studholme (STU)	15.13	10	N-1		151%	10	168%	Transpower	Transpower two 11 MVA transformers, load shedding/shift required
22	Tekapo Village (TEK)	4.65		N		-	15	66%	Transformer	Transformer upgrades in FY21/22 and the TEK substation option of constructing a "twin" substation to provide N-1 security of supply
23	Temuka (TMK)	14.55	25	N-1		58%	25	70%	No constraint within +5 years	Meets Alpine Security standard
24	Timaru 11/33 kV (TIM)	16.64		N		-	-	-	No constraint within +5 years	Meets Alpine Security standard
25	Twizel Village (TVS)	3.99		N		-	-	-	No constraint within +5 years	Options being assessed to upgrade installed firm capacity
26	Unwin Hut (UHT)	1.02		N		-	-	-	No constraint within +5 years	Meets Alpine security standard
27						-				

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 2022 – 31 March 2032

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

	Number of connections					
	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
*Consumer types defined by EDB**						
Low Charge	12,696	12,807	12,919	13,033	13,147	13,263
Low Uncontrolled	59	59	60	60	61	61
015	17,962	18,120	18,279	18,439	18,601	18,764
015 Uncontrolled	77	77	78	79	79	80
360	1,286	1,297	1,308	1,320	1,331	1,343
360 Uncontrolled	30	31	31	31	31	32
Assessed	1,725	1,740	1,755	1,770	1,786	1,802
TOU 400V	140	141	143	144	145	146
TOU 11kV	10	10	10	10	10	11
IND	12	12	12	12	13	13
Connections total	33,995	34,294	34,595	34,899	35,205	35,514

*include additional rows if needed

Distributed generation

Number of connections	528	588	648	709	769	829
Capacity of distributed generation installed in year (MVA)	3	3	3	3	4	4

12c(ii) System Demand

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Maximum coincident system demand (MW) — for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
GXP demand	146	148	151	153	155	157
plus Distributed generation output at HV and above	-	-	-	-	-	-
Maximum coincident system demand	146	148	151	153	155	157
less Net transfers to (from) other EDBs at HV and above	-					
Demand on system for supply to consumers' connection points	146	148	151	153	155	157

Electricity volumes carried (GWh)

Electricity supplied from GXPs	829	831	833	835	837	838
less Electricity exports to GXPs	10	10	10	10	10	10
plus Electricity supplied from distributed generation	18	18	18	18	19	19
less Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
Electricity entering system for supply to ICPs	838	840	842	844	845	847
less Total energy delivered to ICPs	802	804	806	808	810	811
Losses	36	36	36	36	36	36
Load factor	65%	65%	64%	63%	62%	62%
Loss ratio	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%

A.2.6 SCHEDULE 12D

Company Name	**Alpine Energy Ltd**
AMP Planning Period	**1 April 2022 – 31 March 2032**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	65.7	55.0	55.0	55.0	55.0	55.0
12	Class C (unplanned interruptions on the network)	87.9	91.9	91.9	91.9	91.9	91.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.35	0.70	0.70	0.70	0.70	0.70
15	Class C (unplanned interruptions on the network)	0.89	1.20	1.20	1.20	1.20	1.20

A.2.1 SCHEDULE 13

	Company Name	Alpine Energy Ltd
	AMP Planning Period	1 April 2022 – 31 March 2032

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, section 2.5.2	We have implemented an asset management policy as part of the development of our AMF. All asset managers and teams 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	Life cycle strategies for planning, maintenance, operations, and delivery are in draft format within the asset management framework (see section 4.1).	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 have set up maintenance schedules for most 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?	3	Copies of our AMP are available to all interested parties. Company-wide communication is through a mini-business unit (MBU) principle in accordance with lean management practices. As such all MBUs have interaction and communication with one another. Business objectives and KPIs are managed through relationship agreements between teams (MBUs).	We circulate a copy of our AMP to our principal contractor, shareholders, large consumers, and key staff. A copy of our AMP is available at reception and on our website. However, we do not meet with large consumers or other smaller contractors; 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?	3	Master Services Agreement with NETcon Position descriptions of all asset management roles Standard forms of contract ie. NZ 3910 Delegated authority for expenditure is managed through a policy and implemented via our EAM system	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 Master Services Agreement with our in-house service provider details 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 to discuss the works program and ensure all relevant teams and departments are informed. Our service providers price all major projects for evaluation before jobs are issued. All projects and jobs are captured against relevant assets within our EAM system. We have a Master Services Agreement with our main service provider (Netcon) regarding works program delivery. Business Process Maps are being 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 the main service providers to measure the progress of the workplan with 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 (Section 10). 2. Emergency Preparedness Plan, addendum A4 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 section 7.3.5 7. Risk Register in the Health and Safety Vault database.	We have a comprehensive Emergency Preparedness Plan that supports us in managing 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-Asset Management and GM-Service Delivery 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. Master Services 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 asset management team members are documented but not reviewed against strategies and objectives. Communication is through the MBU process.
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. Master Services 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 asset management and service delivery teams structure and associated position descriptions, our implementation of EAM, GIS and SCADA systems. Expansion of our Business Systems team.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	1. Schedule 13 Senior management meeting notes 2. Network meeting notes 3. Job descriptions of senior management 4. Board reports and meeting minutes 5. Master Services Agreement meetings held with NETcon 6. Hard copies of standards manuals 7. The EAM system contains a schedule of delegated authorities 8. Emergency recovery and disaster response arrangements. 9. Communication through MBUs.	Network CAPEX and OPEX are covered as standing agenda items at the fortnightly Network managers' meetings. The delivery program is the main agenda item at the Master Services 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 Master Services Agreement 2. Contracts for delivery in accordance with AS/NZS 3910. 3. TechnologyOne ERP software generates automated reports and documented processes for most asset management activities. 4. New connection sign off sheets.	We have a Master Services Agreement with our preferred contractor, NETcon. The GM-Services Delivery meets regularly with contractors to discuss performance, operational progress and other relevant issues. Fortnightly meetings with service providers review 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. People & Culture team maintains staff training records and a Competency Matrix 2. EEA meeting attendance records 3. People & Culture team plans include HR BPMs. 4. Position descriptions. 5. Draft succession plan/strategy under development.	Our asset management and services delivery teams' structure with line managers and teams focuses on planning, delivery, maintenance and operations, accounting for 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 in our AMP.
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?	3	1. AEL Network Access Policy 2. Competency Matrix training plan. 3. Chartered Professional Engineers Act 2002. 4. People & Culture team recods training requirements as part of staff development reviews, for which targeted training is arranged.	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 required by the work to be carried out. Enduring competency requirements are linked to our AMPs will be a function of our Master Services 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 2 and 7 2. Competency Matrix Training Records 3. BPM for AEL HR processes 4. NETcon Master Services Agreement 5. The AEL Safety Management System (SMS) audit reports. 6. Personal development plans in place. 7. Position description of personal requirements and qualifications.	Every position on our network department structure has a 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 Master Services Agreement and meetings 4. Senior management job descriptions and meetings. 5. Communication through MBU process and regular meetings.	Our AMP is made available to all staff on our internet and hard copies are distributed to the asset management and engineering teams. We meet with our contractors each month to discuss the progression of the works programme. We hold regular shareholder meetings where our asset management programme can be discussed. Our stakeholder engagement, for consumers tends to be ad hoc. We will need to improve our communications to better our score.
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. 3. MBU partnership agreements with objectives and KPIs.	We have completed the mapping of 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. MBU customer and supplier relationships are identified on MBU charts.
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. Deloitte's strategic IT review. 4. Business cases for relevant projects. 5. Commerce Commission information disclosure	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 control 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 Business Systems Manager 2. Review of the ICT system by Deloittes 3. Business Process Mapping development in EAM system. 4. Board meetings and minutes. 5. Formalising our Business Systems strategy.	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 the 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 2. Senior Management completes 'ComplyWith' questionnaire quarterly. 3. Training and Compliance Manager role description 4. Public Safety Management System 5. We have a GM-Commercial & Regulatory to assist with regulatory matters. 6. Health and Safety Policy Statement	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. Master Services 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 Master Services Agreement 4. Fortnightly meetings between NETcon and the AEL Asset Manager 5. EAM records 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 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. Asset fleet strategies 5. Fortnightly meetings between NETcon and the AEL Asset Lifecycle Manager. 6. EAM records outlining basic maintenance status. 7. Condition derived Asset Health Indicators for AELs fleet of poles.	Condition assessments are predominately EAM based (test point) 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 2022 through 2024. 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, chapters 2 and 7 2. AEL Emergency Preparedness Plan, addendum A.4 3. Health & Safety Management System 4. Participant Outage Plan 5. Position descriptions of Senior Management 6. Risk management policy. 7. Communication through MBUs. 8. Investigate, specify and document the correction of asset defects	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 TechnologyOne's 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 2. AEL Emergency Preparedness Plan, addendum A.4 3. Hazard and Incident Report form 4. NETcon Master Services Agreement 5. Fortnightly meetings between NETcon and AEL. 6. Defect reporting and actions as well as red tag pole reporting and mitigation. 7. Reliability reviews, section 5.6.3	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 and RCFA 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?	2	1. Network Risk Management, addendum 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 6. We have developed rate cards for all major types of work activities on our network. These rate cards have been independently assessed as market aligned.	Our Risk Management Policy, as it relates to the network, focuses on risk levels, what is acceptable or not, and the associated costs. Justification of projects is based on the company's risk reduction level. We maintain customer complaints register. Monthly report to Board regarding 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.2.2 SCHEDULE 14a

Company name: Alpine Energy Limited

For Year Ended 31 March 2022

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 2.6.

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 4.5% for 2023, 2.5% for 2024, and 2.0% for the other years, based on New Zealand Treasury forecasts. To derive the 10 year forecast, 4.5% was used for 2023, 2.5% for 2024, and 2.0% for the other years, as conservative inflationary rates. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 4.5% in 2023, 2.5% in 2024, and 2.0% in the other years.

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 capital expenditure in nominal dollar terms, the constant price forecasts were inflated by 4.5% for 2023, 2.5% for 2024, and 2.0% for the other years, based on New Zealand Treasury forecasts. To derive the 10 year forecast, 4.5% was used for 2023, 2.5% for 2024, and 2.0% for the other years, as conservative inflationary rates. Therefore the difference between nominal and constant expenditure forecasts is an inflationary impact of 4.5% in 2023, 2.5% in 2024, and 2.0% in the other years.

A.3 Network risk management

This appendix outlines the risk management approach that we employ for managing our network assets and activities.

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 on the mitigations required to reduce a risk to within our risk appetite threshold. If a risk is above our risk appetite threshold, further risk treatment must be applied, in accordance with a Risk Treatment Plan, to reduce the residual risk to below the threshold.

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 the 15th October 2015 and was again reviewed and updated on the 8th October 2021. Our Risk Management Policy is consistent with the international standard AS/NZS/ISO 31000:2009 Risk Management—Principles and Guidelines.

We aim to integrate high-quality risk management activities with all critical processes so that we recognise and respond to risk before events occur. Our responsibility for managing risks rests with our Board of Directors and all our staff, as described in Table A.3-1. Our accountability for risk management includes ensuring that the necessary risk mitigation and assurance activities are in place and are effective at all times.

Assurance of good governance is achieved through the regular measurement, reporting, and communication of our risk management performance by ensuring resources, delegations, and organisational arrangements are in place.

Table A.3-1 Risk management responsibilities and accountabilities

Title	Responsibility
Board of Directors	The Board is responsible for: • Determining AEL's risk appetite. • Evaluating the effectiveness of the company's risk management policies, practices and procedures via the Audit and Risk Board Committee. • Approving the risk management policy on the recommendation from the Audit and Risk Board Committee. • Seeking the CEO's assurance that the implementation and operation of the risk management policy is effective. • Ensuring information about residual risks assessed as High and Very High and their management is properly communicated back to them.
Audit & Risk Committee (A&RC)	The A&RC is responsible for: • Evaluating the effectiveness of the company's risk management policies, practices and procedures. • Reviewing and approving the Risk Management Policy for recommendation to the Board. • Reviewing the Strategic Risk Register and agreeing on treatment plans. • Monitoring the implementation of treatment plans.
Chief Executive Officer (CEO)	The CEO is responsible for: • Translating and communicating the Board's expectations. • Ensuring the risk management policy is implemented and operational to support the decision-making process. • Providing the environment and resources within which risk can be effectively managed. • Escalating to the Board, High or Very High residual risks that could significantly impact AEL's ability to meet its strategic objectives. • Ensure board reports provide updates on the status of risk treatment plans, with accompanying risk heat map. • Building a risk-aware culture within AEL by actively promoting risk management.
Executive Leadership Team (ELT)	The ELT is responsible for: • Supporting the CEO in the implementation and operation of the risk management policy. • Embedding the risk management processes within their business units and driving continuous improvement. • Understanding and reviewing operational risks within their domain on an ongoing basis to ensure that appropriate steps are taken to manage risk. • Identifying and reporting new and changing risks that have not already been captured. • Cultivating responsibility from risk owners.
General Manager – Safety and Business Risk (GM-SBR)	The GM–SBR is responsible for: • Leading and continuously improving and maintaining the company's risk-based management system. • Maintaining the company's risk registers. • Providing guidance and training on risk management as required. • Supporting risk owners in the development of risk treatment plans. • Monthly, quarterly and annual reporting to the Audit and Risk Committee and the Board.

Title	Responsibility
Level 2 Managers	Level 2 Managers are responsible for: • Assisting their GM in embedding the risk management processes within their business units and driving continuous improvement. • Escalating to the GM new and changing risks that have not already been captured.
Risk Owners	Risk Owners are responsible for ensuring that the risks assigned to them are effectively managed and reported on an ongoing basis. They may delegate the management of specific risks to others within their discipline or team but the responsibility for effective management of these risks remains with the Risk Owner.
Staff	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 -

- Scope, context and criteria.
- Risk assessment (identification, analysis and evaluation).
- Treatment.
- Recording and reporting.
- Monitoring and review.
- Communication and consultation.

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 their 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

The 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 EEA's *Asset Health Indicator (AHI) Guide* and the EEA's *Asset Criticality Guide*).

The consequences of risk on our network can be grouped into the following categories:

- Health and safety (including public safety).
- Stakeholder relationships.
- Business continuity.
- People.
- Reputation.
- Natural environment.
- Regulatory.
- 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 occur that are outside of our control and 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 located 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 access 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

We use a semi-quantitative risk matrix to assist in assessing the causes and sources of risk, the positive or negative consequences, the likelihood that those consequences will occur, the resulting inherent risk, and the residual risk after risk mitigations/treatments are applied. This makes the risk analysis process more systematic (and auditable) for us. Table A.3-2 lists the qualitative measures of likelihood we use in our risk assessment.

Table A.3-2 Measure of risk likelihood

Descriptor	Time based guide	Description	Annual probability
Almost Certain	1 or 2 times per year	A very poor state of knowledge has been established on the threat.	>=50%
Likely	Once per 2- 5 years	A poor state of knowledge has been established on the threat.	>=20% but <50%
Possible	Once per 5-10 years	A moderate state of knowledge has been established on the threat.	>=10% but <20%
Unlikely	Once per 10 -20 years	A good state of knowledge has been established on the threat.	>=5% but <10%
Rare	< once per 20 years	A very good state of knowledge has been established on the threat.	< 5%

Table A.3-3 describes the qualitative measures of consequence and likelihood that we use in our risk assessment process.

Table A.3-3 Measure of risk consequence and likelihood

Consequence level	Insignificant	Minor	Moderate	Major	Severe
Shareholder Relationships	On the odd occasion there is a delay in reaching agreement or approval from shareholders.	No more than minor delays in reaching agreements or approvals from shareholders.	Some significant delays in gaining decisions or approvals as a result of strained relationship with shareholders.	Major conflicting priorities with key shareholders. Multiple points of contact with shareholder(s), resulting in inconsistent or delayed response or actions.	Breakdown in working relationships with one or more shareholder(s).
Asset Utilisation	Network asset <$50,000 underutilised or stranded.	Network asset >=$50,000 but <$100,000 underutilised or stranded.	Network asset >=$100,000 but <$1 million underutilised or stranded.	Network assets >=$1 million but <$5 million underutilised or stranded.	Network assets >=$5 million underutilised or stranded.
Supply Reliability	Network asset <$50,000 underutilised or stranded.	Unplanned outages (Class C): >=2 but <5 SAIDI minutes per event.	Unplanned outages (Class C): >=5 but <10 SAIDI minutes per event.	Unplanned outages (Class C): >=10 but <20 SAIDI minutes per event.	Unplanned outages (Class C): >=20 SAIDI minutes per event.
Supply Security	Non-compliance with SoSS on loads below 0.2 MVA.	Non-compliance with SoSS on loads and generation above 0.2 MVA and below 1 MVA or inability to supply new load within three months.	Non-compliance with SoSS on loads and generation above 1 MVA or inability to supply new load within 12 months.	Non-compliance with SoSS on loads and generation above 9 MVA or inability to supply new load within 24 months.	Non-compliance with SoSS with security supply standard - impact causes negative growth or inability to supply new load within 48 months.
Reputation	No interest outside of AEL.	Local paper(s), brief criticism, little controversy.	Local and regional media criticism not widespread, <2 days.	Regional and national media criticism >2 days but <1 week.	Regional, national and social media criticism, highly adverse, sustained for greater than a week.
Business Continuity	Business interruption <4hrs.	Business interruption >4hrs but <8hrs.	Business interruption >8hrs but <24hrs.	Business interruption >24hrs but <1 week.	Business interruption >1 week.

Consequence level	Insignificant	Minor	Moderate	Major	Severe
	Minor IT failure e.g. readily recoverable loss of data or communication s links. Protection Framework – Green.	Short term IT failure e.g. loss or localised corruption of data, interruption to local area services (email, intranet). Pandemic Alert Leve 1 (Prepare). Protection Framework – Orange.	Significant IT failure e.g. loss or corruption of data, interruption to local server. Pandemic Alert Level 2 (Reduce). Protection Framework – Orange.	Major IT failure e.g. need to recreate important lost or corrupted data, major interruption to IT services. Pandemic Alert Level 3 (Restrict). Protection Framework – Red.	Total loss of IT services for an extended period. Need to replicate systems at alternative location. Pandemic Alert Level 4 (Eliminate). Protection Framework – Red.
People	Staff have occasional issues with the work environment.	Staff turnover <15% p.a. Staff dissatisfaction.	Staff turnover >20% but <30% p.a. Staff disengaged.	High staff turnover >30% pa. unable to recruit staff or retain skill set. Staff actively disengaged. ELT member leaves the company at short notice causing BAU inconvenience.	Unable to recruit or retain staff causing staff numbers to drop below sustainable BAU level. CEO leaves the company at short notice.
Regulatory	Breach of legislation, code of practice, or industry standard; no applicable penalties.	Financial penalty up to $100,000.	Financial penalty >=$100,000 but <$1m.	Prison term of less than two years and/or financial penalty >=1m but <$5m.	Prison term of more than two years and/or financial penalty >= $5m.
Finance	Financial loss < $500k.	Financial loss >=$500k but <1m.	Financial loss >=$1m but <$5m.	Financial loss >=$5m but <$10m.	Financial loss of >=$10m or more.

Consequence level	Insignificant	Minor	Moderate	Major	Severe
			Guidelines - 10% turnover. - 25% available lending balance ($20 M). - 5% annual expenditure. - 33% of annual capex programme.	Guidelines - 20% turnover. - 25% available lending balance ($20 M). - 33% annual expenditure. - 60% of annual capex programme.	Guidelines - 50% turnover - 50% available lending balance ($20 M). - 100% annual expenditure. - 125% of annual capex programme.
Health & Safety (incl. Public Safety)	No injury or health effect. No injury sustained due to failure of AEL asset.	First Aid Case - injury or health effect. Not affecting work performance and not affecting daily life activities. Member of the public (s) injured but does not require treatment due to failure of AEL asset.	Medical Treatment Cases. Reversible health effects (e.g. skin irritation, food poisoning). Member(s) of the public requires treatment by a doctor due to failure of AEL asset.	Lost Time Injury or Notifiable event to WorkSafe. Long term health effects (e.g. chronic back injury, repetitive strain injury). Member of public(s) requires time of work due to failure of AEL asset.	Fatality or permanent disability. Permanent health effects (e.g. asbestosis, cancer, loss of a limb, silicosis, corrosive burns). Fatality or permanent disability to a member(s) of the public due to failure of AEL asset.

Consequence level	Insignificant	Minor	Moderate	Major	Severe
Environment	Negligible and sporadic environmental effects. No threat to significant flora or fauna.	On-site effects immediately addressed, cleaned up, mitigated etc. Minor threat to significant flora or fauna.	Off-site effects with no obvious detrimental effects to the environment. Recoverable impact on significant flora or fauna. Damage to items/area of cultural value.	Off-site release with obvious detrimental effects on environment. RMA notice likely to be served by council. Damage to significant flora or fauna requires years to recover. Significant damage to items/area of significant cultural value.	Major spill / release, destruction, with widespread damage to environment / property. Likely prosecution in Environment court. Permanent impact threatens survival of significant flora or fauna. Destruction of items/area of significant cultural value.

Table A.3-4 combines the qualitative assessment of consequence and likelihood to provide a level of risk matrix.

Table A.3-4: Consequence And Likelihood Combine Into Risk Level

Likelihood					
Almost Certain	Low	Medium	High	Very High	Very High
Likely	Low	Medium	High	High	Very High
Possible	Low	Medium	Medium	High	Very High
Unlikely	Very Low	Low	Low	Medium	High
Rare	Very Low	Very Low	Low	Medium	High
	Insignificant	**Minor**	**Moderate**	**Major**	**Severe**

Consequence

Based on the residual risk assessment, specific actions, accountability, acceptance and reporting requirements are determined. The is described in Table A.3-5 below.

Table A.3-5 Response by risk level

Residual Risk Rating	Action, Accountability, Acceptance			
	Action	When to escalate/report	Who to	Acceptance of risk
Very High	Immediate and decisive action to treat risk. Requires risk treatment plans to be developed.	Immediate and as appropriate	Board/ELT	Board
High	Timely action to treat risk. Requires risk treatment plans to be developed.	Monthly and as appropriate	Board/ELT	A&RC
Medium	Treat risk if reasonably practicable	Quarterly and as appropriate	GM/ELT	CEO
Low	Treatment evaluation not specifically required. Managed using routine procedures.	Annual and as appropriate	GM/Level 2 Managers	GM
Very Low	Does not require specific management. Watching brief only.	Annual and as appropriate	Level 2 Managers	GM

Quantitative analysis is used to assess risk where specific performance measures are in place. The quantitative analysis approach allows us to manage our assets with the highest event consequence cost throughout it's expected service life. For example, the testing of zone substation transformer oil samples (provides a review of the compounds within the oil sample and) can be used to determine the health and position of the transformer on it's age curve througout it's service life.

A.3.3 RISK EVALUATION

Risk evaluation involves us comparing the results of the risk analysis with the established risk criteria to determine where additional action is required. This can lead to a decision to:

- Do nothing further.
- Consider risk treatment options.
- Undertake further analysis to better understand the risk.
- Maintain existing mitigations.
- Reconsider objectives.

A.3.4 RISK TREATMENT

Treatment involves us developing a range of options for further mitigating the risk, assessing those options, and then preparing and implementing risk treatment plans where required.

In selecting the most appropriate risk treatment, we ensure the assessment balances the potential benefits from risk reduction and the increased likelihood of achieving business objectives against costs, effort or disadvantages of implementation.

We recognise risk treatment options are not necessarily mutually exclusive or appropriate in all circumstances. Depending on the type and nature of the risk, the following options are available for consideration and adoption by us:

- Avoiding the risk by deciding not to start or continue with the activity that gives rise to the risk.
- Removing the risk source.
- Changing the likelihood.
- Changing the consequences.
- Sharing the risk (e.g. through contracts, buying insurance).
- Retaining the risk by informed decision.

A.3.5 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 lines traverse the region and support 11 kV assets and distribution level transformers, which break down into the LV networks and more than 33,000 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 in section 6.5.11.

Zone substation transformers

Table A.3-6 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 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 seven 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 in 2022/2023.

Table A.3-6 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 more than 1200 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, some 2500 ICPs.
Albury	Reliability of supply	Medium	Loss of supply to more than 1000 ICPs.
Fairlie	Reliability of supply	Medium	Loss of supply to more than 1000 ICPs.
Tekapo	Reliability of supply	Medium	Loss of supply to around 650 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 around 1400 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.3-6.

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.3-7. All new switchboards that were installed in the last nine 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.3-7 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 1719 and 1539 ICPs for the two busbars respectively.
Hunt Street	Reliability of supply	Medium	Loss of supply to 1861 and 1442 ICPs for the two busbars respectively.
Pareora	Reliability of supply	Low	Loss of supply to 326 and 839 ICPs for the two busbars respectively.
Temuka	Reliability of supply	Low	Loss of supply to 1746 and 1884 ICPs for the two busbars respectively.
Rangitata[62]	Reliability of supply	Low	Loss of supply to 208 and 250 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 2439 and 915 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 (switched). 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.

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.3-7 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 risk score to low.

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

A.3.6 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 that appropriate materials suitable for 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[63] event in the next 50 years is 30%[64]. 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 or months depending on the damage to hydro stations in the Mackenzie. 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 installed a second submersible pump 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 digital environments are stretched and replicated across multiple locations. This gives us the ability to recover and be fully operational in the event of a system outage. Our disaster recovery substation has additional space and facilities providing a secondary control room operations centre which can be used if an event destroys or damages the Washdyke offices and depot.

A.3.7 RISK MANAGEMENT STRATEGIES

As previously mentioned, if a risk is above our risk appetite threshold, further risk treatment must be applied, in accordance with a Risk Treatment Plan, to reduce the residual risk to below the threshold.

We accept that not all risks can be mitigated to be within our agreed risk appetite threshold. Where this is the case, risks that are outside AEL's standard risk appetite are properly assessed and approved consistent with AEL's Delegated Authorities and this Policy.

In mitigation we look to eliminate, isolate or minimise the risk from health and safety (incl. public 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.

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 sent to the respective GM, and in consultation with the GM Safety and Business Risk, a determination is made as to whether the risk should be recorded in the risk register for assessment and action as required of our Risk Management Policy.

[63] 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

[64] According to the GNS Science website.

A.4 Safety management framework

This appendix outlines the safety management framework we employ for managing our network assets and activities whilst endorsing that the safety of the public, our staff and service providers is vital.

We are committed to supplying electricity in a safe and environmentally sustainable manner and in a way that complies with statutes, regulations and industry standards from the various government bodies and regulators that have jurisdiction over our activities e.g. WorkSafe, Electricity Authority.

The most notable pieces of legislation that we comply with are:

- Health and Safety at Work Act 2015
- Health and Safety at Work (General Risk and Workplace Management) Regulations 2016
- Electricity Act 1992 (and subsequent amendments)
- Electricity (Safety) Regulations 2010
- Electricity Industry Act 2010
- Electricity (Hazards from Trees) Regulations 2003
- Resource Management Act 1991 (and subsequent amendments)
- Hazardous Substances and New Organisms Act 1996

We also abide by the Electricity Authority's Electricity Industry Participation Code as well as the Electrical Codes of Practice (ECP) issued by the Electricity Engineers Association (EEA).

Whilst there several ECP's that apply to our business, the most important of these are:

- ECP34 - Electrical Safe Distances
- ECP46 - High Voltage Live Line Work

Additionally, under the Electricity (Safety) Regulations 2010, we are required to implement and maintain a safety management system that complies with *NZS 7901:2014 Electricity and Gas Industries—Safety Management Systems for Public Safety*. The purpose of the Public Safety Management System is to show that all practicable steps have been taken to ensure our assets do not present a significant risk of serious harm to any member of the public or significant damage to our property.

Annually, an accredited audit body must confirm our system is meeting the requirements as specified in Regulation 51 of the said act and we achieve this by retaining Telarc as our accredited auditor and certifier. We are currently certified and are audited by Telarc in June of each given year.

We are confident we abide by and meet the requirements of the above acts, regulations and codes of practice. We achieve this confidence by the successful results in our Leading Indicators e.g. number of completed internal observations, inspections and director conversations (where we action any non-conformities), issuing and compliance with Close Approach (for vegetation and third party work within 4 metres of our assets) and BeforeUdig permits, staff/network contractors compliance with network competency framework requirements.

A.4.1 EMERGENCY RESPONSE AND CONTINGENCY PLANNING

We recognise that the local economy depends on a secure and reliable supply of electricity. We have defined an emergency as an unplanned event that presents or has the potential to have a significant impact on the normal operation of our network.

Unplanned events that may cause an emergency within our Network include (but are not limited to):

- Natural disasters e.g. flooding, earthquake, wind, snow storms
- Major transmission network failure
- Significant natural or human threat e.g. a pandemic

We have implemented the following general guidelines for classification of an event as an emergency:

- Where it is determined by the Executive Leadership team that the nature of the event has had a significant impact on our customers and/or our assets and justifies diverting work from BAU
- The declaration of a civil defence emergency

We currently have in place the following high-level emergency and contingency plans, procedures or agreements:

- Emergency Preparedness Plan
- Pandemic Response Plan
- Participant Rolling Outage Plan
- Load Management (as defined in Schedule 8, Distributors Default Agreement)

The aim of the above is to sustain electricity network capabilities due to unplanned emergencies by effective network management and practices.

Reviews of all plans/procedures/agreements are completed as scheduled in our document register, or after an emergency, to challenge and validate the processes contained within.

We have also signed Mutual Assistance Agreements for emergencies with peer EDB's.

A.4.2 CIVIL DEFENCE EMERGENCY MANAGEMENT

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 in Civil Defence's annual regional exercises when they are conducted. Lessons learnt from these exercises are captured and reviewed to determine any improvements to our plans/procedures/agreements.

We are part of the Canterbury Lifelines Utilities Group. The groups aim is to promote resilience to risks, and develop contingency measures for Civil Defence emergencies arising from natural disasters.

A.5 Load forecasts

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

A.5.1 LOAD FORECAST FOR THE ALBURY REGION SUBSTATIONS IN MW

Substation	N security (MVA)	Lowest rated equipment (MVA)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Albury GXP	20.00	11.30	5.57	5.65	5.72	5.79	5.85	5.92	5.99	6.06	6.12	6.19	6.26
Albury zone substation	7.50	6.92	5.08	5.18	5.27	5.37	5.46	5.56	5.66	5.76	5.87	5.97	6.08
Fairlie zone substation	6.25	5.38	3.48	3.68	3.88	4.10	4.33	4.57	4.82	5.09	5.37	5.67	5.99

For Albury we have used forecast based on the historical medium term actual load growth since this represents a more realistic scenario.

A.5.2 LOAD FORECAST FOR THE BELLS POND REGION SUBSTATIONS IN MW

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Bell Pond GXP	60.00	20.00	55.63	17.51	21.77	22.54	23.30	24.06	24.83	25.59	26.35	27.11	27.88	28.64
Bell Pond zone substation	60.00	20.00	34.98	17.37	21.95	23.32	24.78	26.33	27.97	29.72	31.58	33.55	35.65	37.87
Cooneys road zone substation	15.00		21.03	5.84	9.34	9.34	9.34	9.34	9.34	9.34	9.34	9.34	9.34	9.34

A.5.3 LOAD FORECAST FOR THE STUDHOLME (WAIMATE) REGION SUBSTATIONS IN MW

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Studholme GXP	20.00	10.00	23.27	15.80	16.04	16.27	16.51	16.75	16.99	17.23	17.47	17.71	17.94	18.18

A.5.4 LOAD FORECAST FOR THE TEKAPO REGION SUBSTATIONS IN MW

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Tekapo GXP	10.00	-	10.46	5.11	8.16	10.35	10.50	10.65	10.80	10.95	11.10	11.25	11.40	11.55
Tekapo Zone Substation	15.00*	-	9.45	4.75	7.33	9.51	9.70	9.89	10.09	10.29	10.50	10.71	10.92	11.14
Haldon Lilybank Zone Substation	1.00	-	1.14	0.48	0.50	0.50	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Old Man Range Zone Substation	1.50	-	1.40	0.39	0.45	0.46	0.48	0.49	0.51	0.52	0.54	0.56	0.58	0.60
Unwin Hut Zone Substation	1.50	-	2.86	1.02	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44

* TEK transformer capacity only

A.5.5 LOAD FORECAST FOR THE TEMUKA REGION SUBSTATIONS IN MW

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Temuka GXP	108.00	54.00	57.72	60.25	66.14	70.34	72.53	74.83	77.03	79.33	81.67	83.97	86.17	86.97
Temuka Zone Substation	50.00	25.00	39.71	15.50	15.99	16.50	17.02	17.56	18.11	18.68	19.42	20.03	20.67	21.32
Geraldine Zone Substation	7.00*	-	12.06	7.39	8.70	8.83	8.97	9.10	9.24	9.38	9.52	9.67	9.82	9.96
Rangitata Zone Substation	30.00	10.00	10.00	11.00	11.35	11.72	12.10	12.49	12.90	13.32	13.75	14.20	14.66	15.13
Clandeboye 1 Zone Substation	40.00	20.00	40.46	13.80	15.15	16.98	16.79	18.11	17.91	17.71	18.91	18.70	19.89	19.67
Clandeboye 2 Zone Substation	50.00	25.00	47.39	20.07	22.46	23.86	25.26	25.26	26.66	28.16	28.16	29.66	29.66	29.66

* GLD transformer capacity only

A.5.6 LOAD FORECAST FOR THE TIMARU REGION SUBSTATIONS IN MW

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032

Timaru GXP	141.00	94.00	88.25	66.04	88.34	98.15	101.16	100.97	100.78	100.59	100.40	100.21	100.03	99.84
Timaru zone substation	141.00	94.00	88.25	67.46	90.62	101.53	105.74	106.80	107.87	108.94	110.03	111.13	112.25	113.37
Grasmere zone substation	31.60	23.70	41.92	23.99	25.48	25.73	25.99	26.25	26.51	26.78	27.05	27.32	27.59	27.87
North street switching station	50.40	38.00	30.33	11.87	14.07	14.21	14.35	14.50	14.64	14.79	14.94	15.09	15.24	15.39
Hunt Street switching station	22.40	16.80	30.33	9.47	9.57	9.66	9.76	9.86	9.96	10.06	10.16	10.26	10.36	10.47
WSS zone substation	30.40	-	7.62*	12.66	27.37	37.64	38.02	38.40	38.78	39.17	39.56	39.95	40.35	40.76
Pareora zone substation	30.00	15.00	33.00	10.16	10.73	10.95	11.18	11.41	11.64	11.88	12.12	12.37	12.62	12.88
ATM zone substation	50.00	-	13.72**	17.18	17.87	18.14	18.41	18.69	18.98	19.27	19.56	19.86	20.16	20.48
Pleasant Point zone substation	6.25	-	6.76	5.02	5.13	5.18	5.23	5.29	5.34	5.39	5.45	5.50	5.56	5.61

* Limit per feeder

** Limit per subtransmission circuit

A.5.7 LOAD FORECAST FOR THE TWIZEL REGION SUBSTATIONS IN MW

Substation	N security (MVA)	N-1 security (MVA)	Branch limit (MVA)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Twizel GXP*	20	-	6.86	4.79	5.21	5.33	5.45	5.57	5.68	5.80	5.92	6.04	6.16	6.27
Twizel Village zone substation	6.25	-	8.57	4.12	4.25	4.39	4.53	4.68	4.83	4.99	5.15	5.32	5.49	5.67

A.6 Region schematic diagrams

This appendix contains the schematic Single Line Diagrams (SLDs) for each region. For illustration of the location on the national grid, refer to the overall SLD in Figure 3-2.

A.6.1 ALBURY REGION NETWORK CONFIGURATION

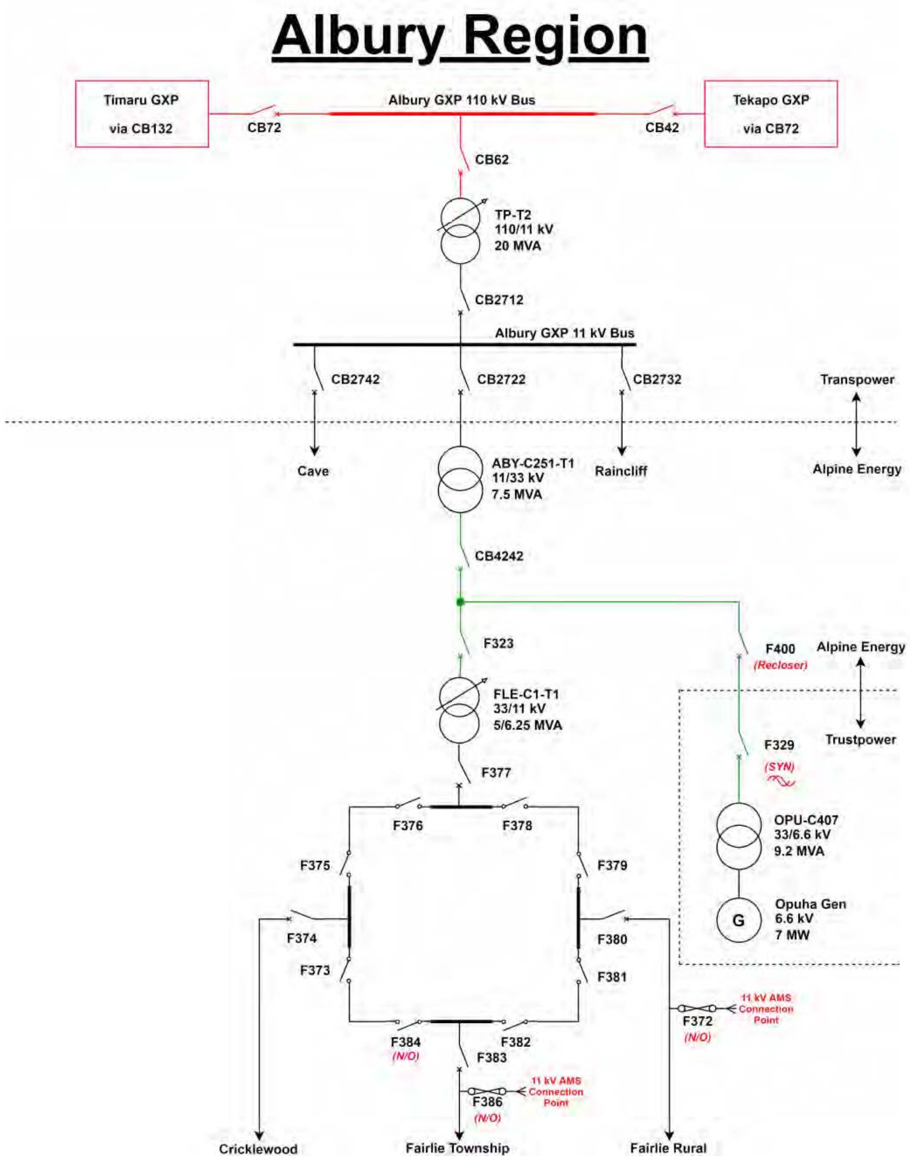
The Albury GXP is fed off the TIM–TKA 110 kV line and has a single 110/11 kV transformer connected to an 11 kV switchboard. The transformer was upgraded in 2017 from 6 to 20 MVA. These are Transpower assets.

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 sub-transmission feeder (overhead). This same 33 kV feeder connects to the Opuha power station[65] (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).



65 www.opuhawater.co.nz

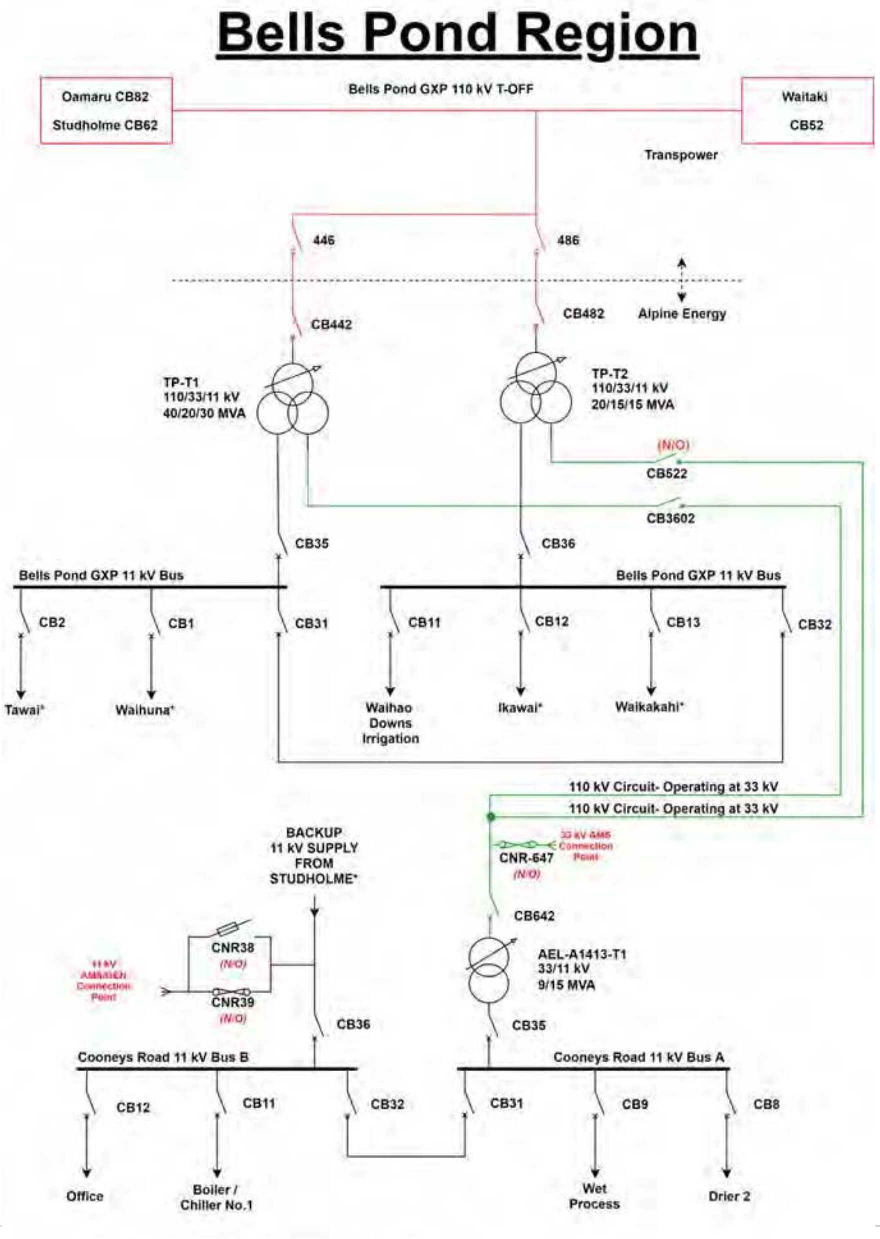
A.6.2 BELLS POND REGION NETWORK CONFIGURATION

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 two 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 sub-transmission line (dual paralleled 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 1 MW).



* Marked feeders interconnect with STU for backup supply

A.6.3 STUDHOLME (WAIMATE) REGION NETWORK CONFIGURATION

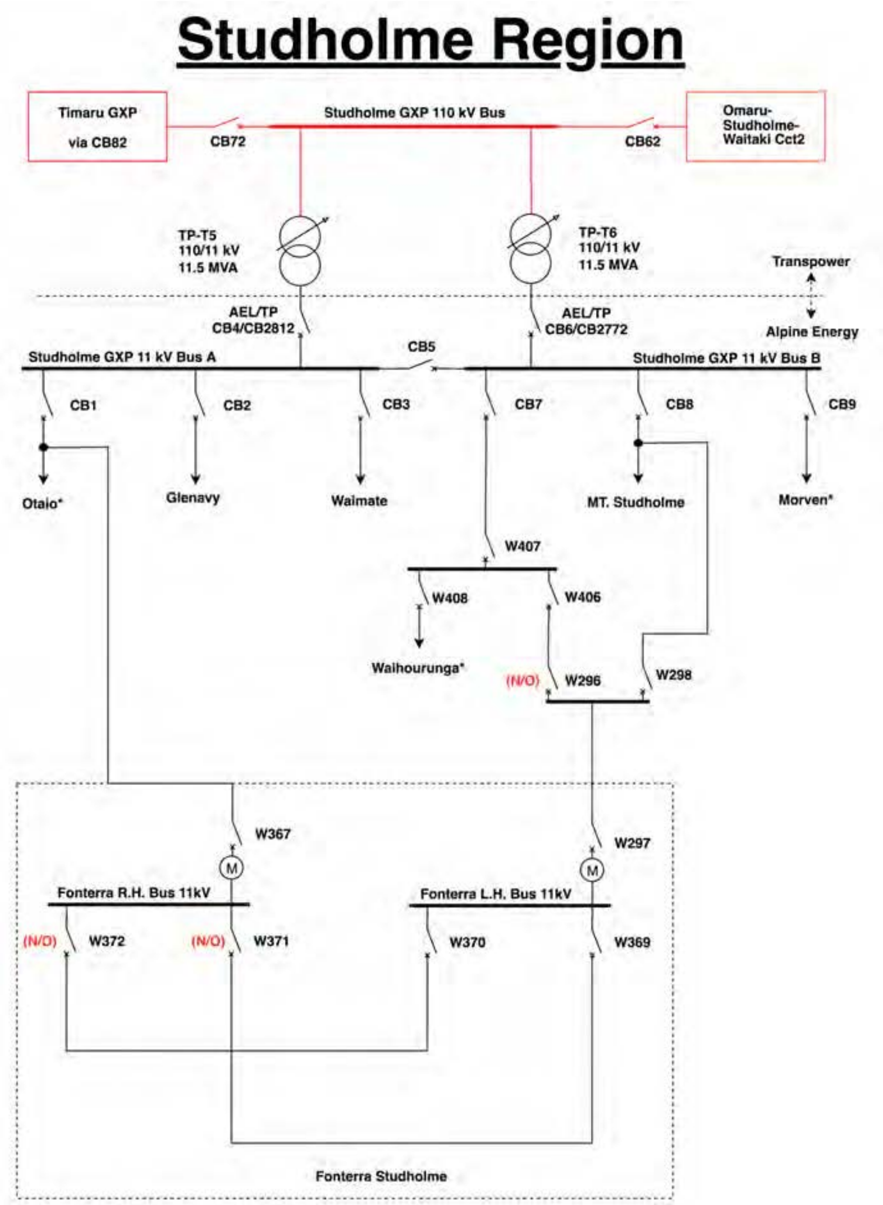
The Studholme GXP is supplied from the 110 kV transmission from Timaru and from Waitaki. The 110 kV system is normally split on a manually operated switch (STU DS76) from 30 April until 1 October. This means the Studholme GXP is supplied from Waitaki. During the dairy season this switch is run closed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

There are two 110/11 kV, 10/12/12 MVA transformers (single phase units) 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 11 kV switchboard and building is located on Transpower land.

The Fonterra Studholme dairy factory is supplied from three 11 kV distributions feeders (not dedicated) through a switching station (adjacent to the factory) comprising ring main units.

The ripple injection plant is connected to the Morven 11 kV distribution feeder.



* Marked feeders interconnect with BPD and CNR for backup supply
(M) - Metering point

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 and 2020.

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 sub-transmission circuit to our 33/11 kV Tekapo zone substation (9/15 MVA transformer). From Tekapo zone substation we have a 33 kV sub-transmission line to Glentanner and Unwin Hut substations respectively.

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.

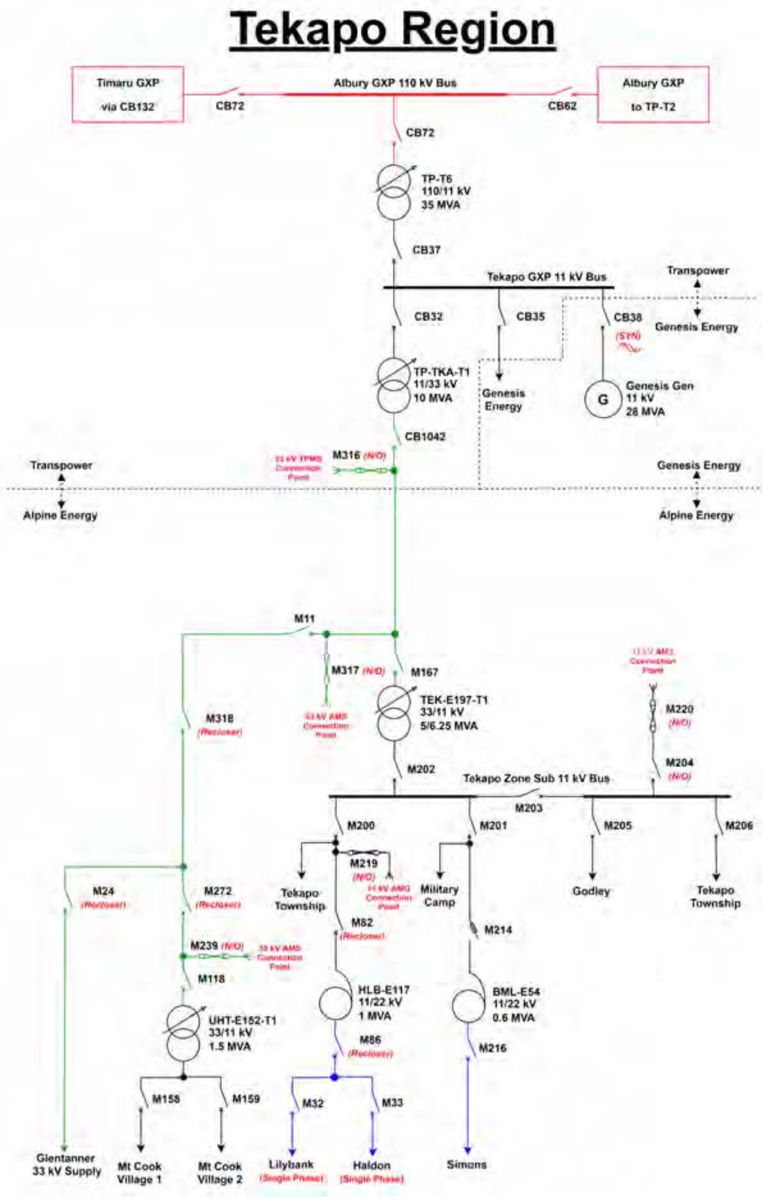
A 33 kV ripple plant is connected via a tap-off connection on the 33 kV sub-transmission circuit.

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 five 11 kV feeders.

Old Man Range (OMR – 1.5 MVA autotransformer) 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.



A.6.5 TEMUKA REGION NETWORK CONFIGURATION

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

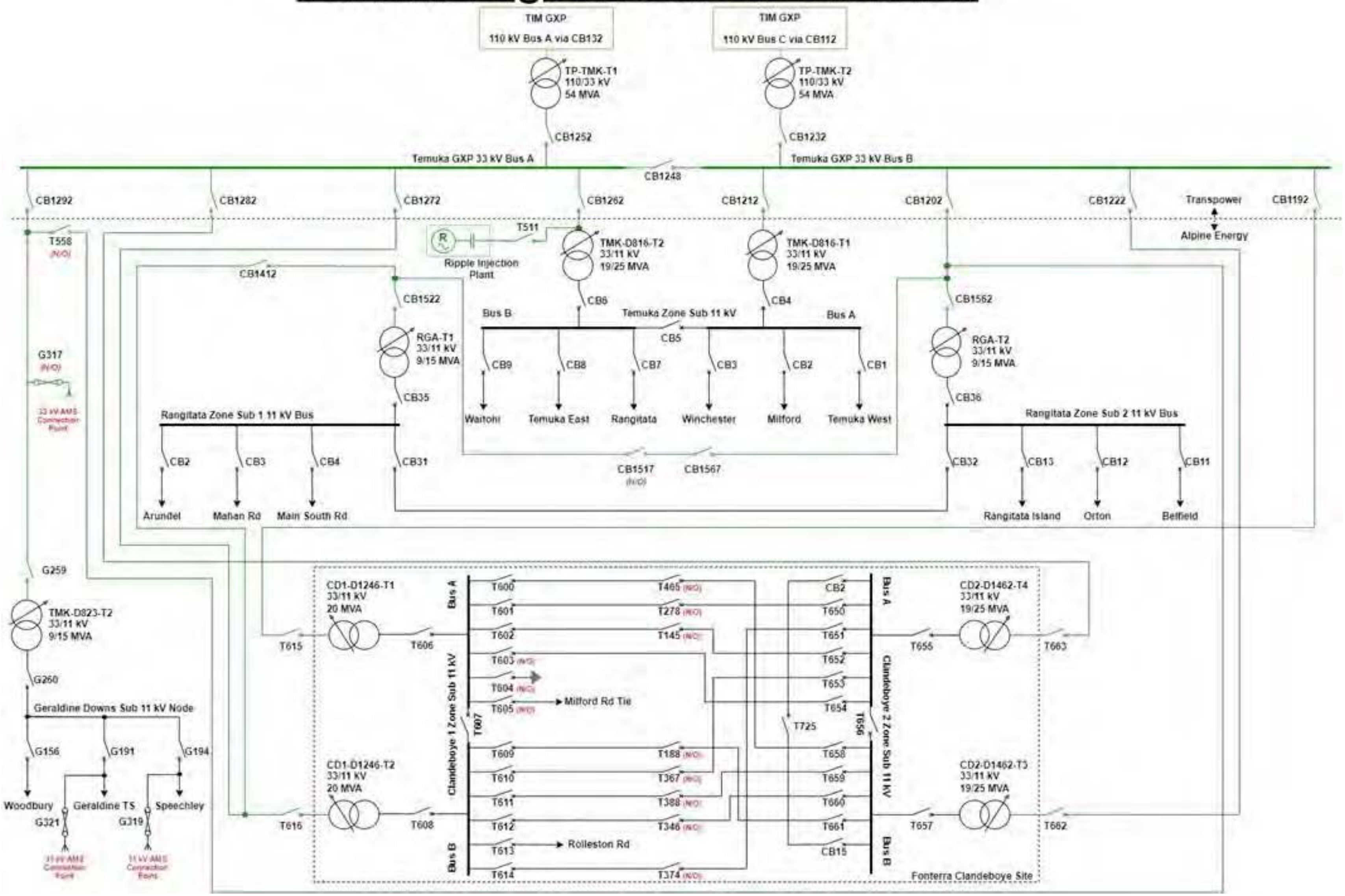
At the GXP, there are two 110/33 kV, 54 MVA power transformers which supply into a double switchboard. These transformers have a Special Protection Scheme (SPS) applied to mitigate against a total supply loss in the unlikely event of a transformer, or 110 kV line trip, while the load is more than 54 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 sub-transmission 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 sub-transmission 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 sub-transmission 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 sub-transmission feeders that supply our Temuka zone substation.

Temuka Region Network Overview

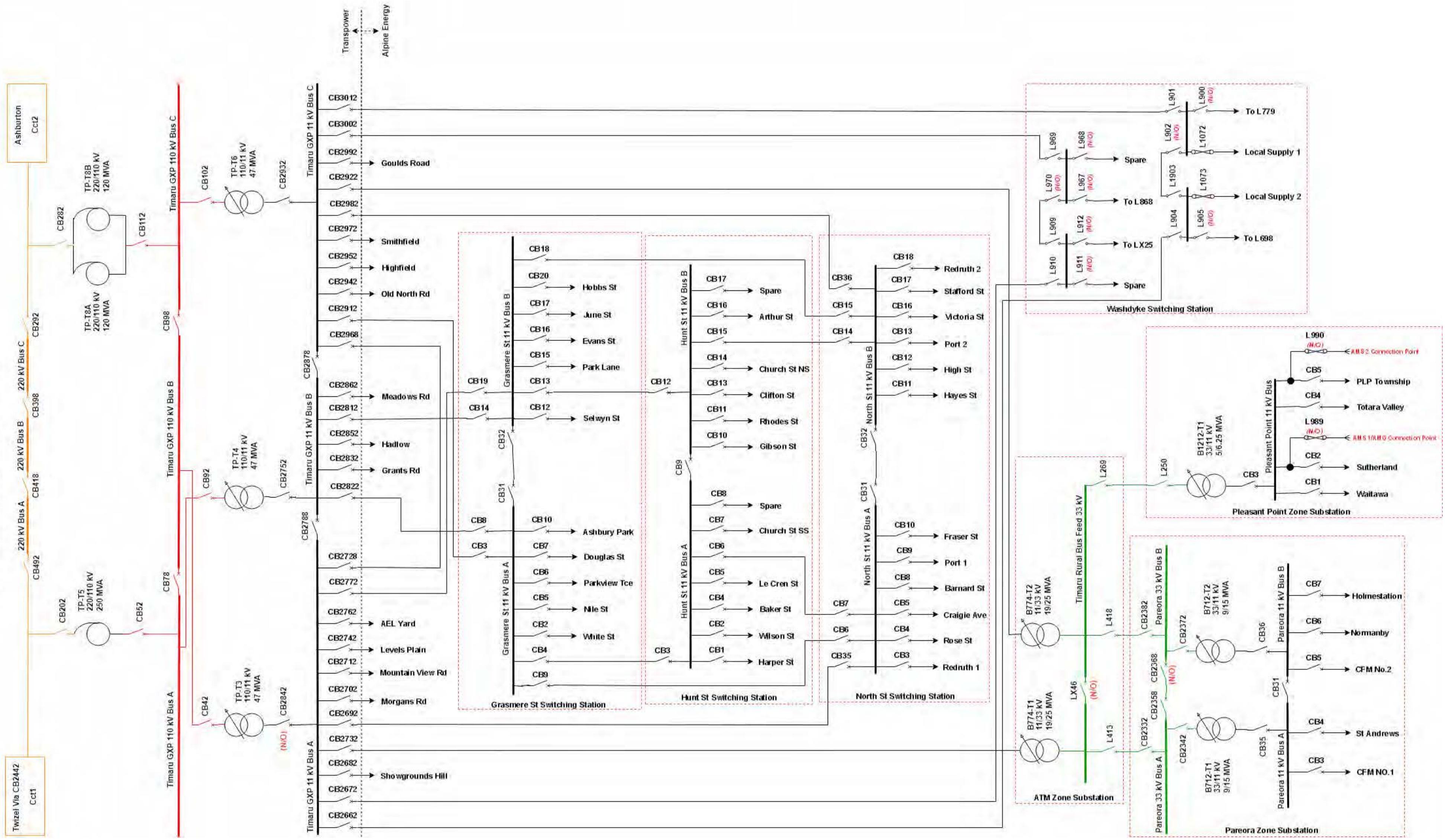


A.6.6 TIMARU REGION NETWORK CONFIGURATION

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 sub-transmission feeder to Pleasant Point zone substation and two 33 kV sub-transmission 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 substation 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



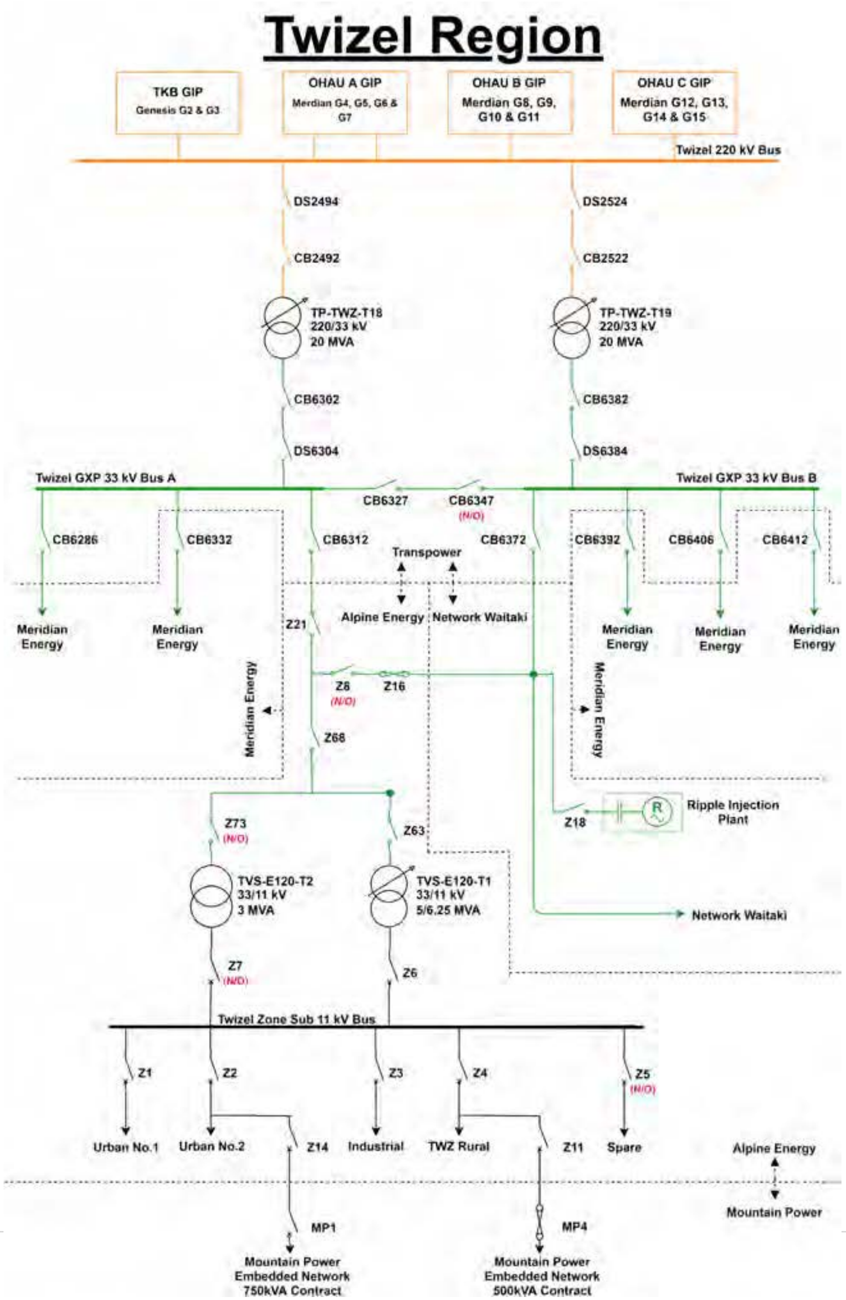
A.6.7 TWIZEL REGION NETWORK CONFIGURATION

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.



SCHEDULE 17 CERTIFICATION FOR YEAR-BEGINNING DISCLOSURES

We, Warren McNabb and Linda Robertson, being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of Alpine Energy Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

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

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Alpine Energy Limited's corporate vision and strategy and are documented in retained records.

Director

31st March 2022

Date

Director

31st March 2022

Date

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

Asset Management Plan 2022