Orion New Zealand Limited
Asset Management Plan

Asset Management Plan 2023

Cover: Christchurch Riverside Market in Oxford Terrace is a social and dining mecca for the city – a hub of small artisan businesses that depend on reliable power from Orion.

Tēnā koe

The Future is Electric – a recently released report by Boston Consulting Group which Orion participated in – coincides with a consensus being reached across the sector and more broadly: that the future is indeed electric and the electricity sector has a key role to play to decarbonise Aotearoa New Zealand. This report also highlighted the urgency for action, the unprecedented level of investment required and the lead role electricity distributors such as Orion have to play, with distributors accounting for the majority of the investment estimated as required in the 2020s.

Given this broad consensus on the actions needed at a macro level and the need to start investing now, we have put forward our best estimate of the investments required of Orion's network not only to decarbonise but also to ensure we have a modern resilient network that can deliver the quality of service our customers expect.

In this AMP we have taken our best estimate of the direction and magnitude of the challenges and opportunities to meet Aotearoa New Zealand's increasing reliance on electricity, the impacts of climate change and new customer expectations. It is an ambitious plan.

We are not alone in recognising our traditional, incremental, business-as-usual approach will no longer cut it – it is a sector-wide realisation. With change and new opportunities comes a greater need for investment and this AMP reflects that reality.

Over the next 10 years, we will make a step-change in how we approach management of our network. It's a cool time to be part of an industry that is growing in importance in people's lives – to deliver on our Purpose:

Powering a cleaner and brighter future with our community

I look forward to being part of Orion's evolution to put electricity at the centre of our region's changing world.

Nāku noa, nā

Nigel Barbour
Orion Group Chief Executive

Orion

Liability disclaimer

This Asset Management Plan (AMP) has been prepared and publicly disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012.

Some of the information and statements contained in this AMP are comprised of, or are based on, assumptions, estimates, forecasts, predictions and projections made by Orion New Zealand Limited (Orion). In addition, some of the information and statements are based on actions that Orion currently intends to take in the future. Circumstances will change, assumptions and estimates may prove to be wrong, events may not occur as forecasted, predicted or projected, and Orion may at a later date decide to take different actions to those it currently intends to take.

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1 Executive summary

Photo: participants in our Powerful Conversations workshops provide their views on various decisions facing Orion.

Introducing our 2023 Asset Management Plan

This Asset Management Plan sets out Orion's asset management policy, strategy, practices and expenditure forecasts for the next 10 years from 1 April 2023.

We have set Orion on a path to gear-up for a very different energy future. Our 2023 AMP is an ambitious plan, focused on delivering on our role in the urgent transformation of our sector for the people and businesses of our community. While many of the challenges and opportunities facing the energy sector are universal, we have not lost sight of the fact that each EDB region's circumstances and needs are unique. We are very conscious of the need to factor the distinct circumstances of the Central Canterbury region we serve into our strategy and planning. As the cornerstone of the Orion Group Strategy, our asset management strategy has been deeply considered and data driven where possible.

In this AMP we share who we are, where we are headed, and our strategies for managing the changes in our operating environment. We set out the risks we face in managing our assets, what our customers are telling us, the condition of our assets and distribution system, how we plan to maintain and key projects to develop our network, and how we support delivery of our planned programme of work.

At the heart of this plan is our commitment to meeting the challenges and opportunities presented by New Zealand's increasing demand for electricity, the impacts of climate change, and new technology.

Our approach to this period of significant change, increased complexity and growth in our sector includes embracing the benefits of new technology, enhancing our knowledge and skill base, and doing things smarter and more efficiently.

The rate and direction of change is hard to predict, so we consider a range of different scenarios.

While where we ultimately land remains unsure, the general direction for electricity distribution businesses is clear: we need to invest in a modern, open network framework to continue to meet the needs of our customers.

Our strategy

In 2023 we took the opportunity to review our Group Strategy and refined it in light of the challenges we face in the coming decades. At its heart, our commitment to our Purpose remains unwavering: Powering a cleaner and brighter future with our community.

In service of our Purpose, our key asset management goals for the Orion network over the next five years are:

- facilitating decarbonisation at lowest cost
- investing to maintain a safe, secure and reliable network at lowest total lifecycle cost

We have set Orion on a path to gear-up for a very different energy future.

We aim to drive down costs by:

- creating a more highly utilised network
- implementing a more efficient and effective works management system
- using real time data and new technology such as drones to locate faults and restore power
- optimal timing of asset renewals

In establishing our asset management strategy for this AMP period we have considered a range of external factors that are having a growing impact on our network, along with the unique circumstances of our region, see Section 2.3.1.

The investment set out in this AMP will enable us to enhance the our ability to accommodate the range of drivers of investment in our network we have identified. These include growth, supporting process heat customers in their decarbonisation efforts, addressing the potential loss of hot water control, adapting to the impacts of climate change, and providing opportunities for customers to participate in new energy markets.

For each for these drivers of investment in our network we have established a strategy for how we intend to respond.

In many cases, the pace and trajectory of change is unclear, and we have considered a range of scenarios in our planning. Being agile, responsive to change and embracing innovation are key to Orion serving its community well, now and into the new future.

While we face huge change in coming years and a rate of growth in demand for electricity which is unprecedented, Orion is confident it has the agility and planning foresight to continue to serve its customers well, at lowest possible cost, in the evolving energy environment.

The pace and trajectory of change is unclear, so we consider a range of scenarios.

What's new, what's changed?

This year's AMP reflects the steps we are taking on our journey to transform our network. From our 2022 AMP, we have made the following significant changes:

- More fully articulated our **investment drivers and our strategies** to respond to them
- **Heightened our focus on the climate emergency and the impact on our network operations**
- Provided more commentary and forecast increased expenditure on our **tree management programme**
- **Add the risk of insufficient workforce numbers and skills to implement our plan in the medium term,** and in the sector overall
- **Increased our capital and operational expenditure** significantly from FY26
- Expanded our commentary on Orion's **data and digitisation plans** and their benefits to operational efficiency and service
- Expanded our commentary on how we **respond to customer complaints**
- Expanded our commentary on **innovations** we have implemented and our process to stimulate innovation in practice

Managing new risks

The energy sector is moving through a period of unprecedented change, while contending with the global challenges of the climate emergency, pressure on resources, cost inflation and geopolitical conflict. These factors lead to a complex and dynamic risk context for Orion.

We are vigilant in identifying and assessing risks, and continually improving our processes and outcomes.

Health and safety, earthquakes and weather events continue to be our highest rated risks and we have programmes in place to manage these risks.

In this AMP, we have elevated the risk of a cyber security breach, and introduced the lack of workforce availability and skills as a new risk.

Difficulties in finding and retaining a skilled workforce have become both a challenge and a risk for businesses across geographies and industries. Our industry is going through an era of unprecedented change, and there is sector-wide consensus that the industry workforce will need to increase greatly in size to meet the increased demand for capability and new skills. Our ability to operate and deliver our Purpose and meet our customer's future needs relies on the availability of competent, experienced, and skilled people.

In this AMP, we have elevated the risk of a cyber security breach, and introduced the of lack of workforce availability and skills as a new risk.

COVID-19 continues to impact our costs and supply chain, in particular on manufacturing and time frames for shipping, although to a lesser degree than previously. We anticipate these delays will continue, albeit due to other geopolitical and climate factors.

For all our key strategic and operational risks, we have risk mitigation strategies in place, and a robust process to evaluate their effectiveness.

Ensuring customer experience and performance meet targets

In a changing world, seeking out our customers' views and giving them a voice in our decision making is vital. Being customer-centric means we champion what is important to our customers when making our asset investment decisions and consider their needs in our asset management practices. We ask customers for their perspective on a wide range of topics including our service, investment priorities, how we might improve our communications, and our approach to preparing for the future.

We measure our customers' satisfaction with our performance through a robust annual research programme.

We are proud to report our customers continue to rate us highly and provide us with insights that help identify opportunities to improve our performance. See Figure 4.3.1.

We measure our performance in asset management practice through an independent assessment by WSP Opus using an industry recognised tool, AMMAT. See Figure 4.5.2.

For our performance against rigorous targets set by the Commerce Commission and those we set ourselves, see Table 4.5.1.

Our planning approach

We have a rigorous process to evaluate opportunities and issues that may prompt network development programmes. Throughout, we are conscious of our goals to facilitate decarbonisation and to invest to maintain a safe, secure and reliable network, both at lowest cost.

With the rapid change that is difficult to accurately predict expected over this AMP period, our planning approach provides for regular review and adjustment of our network investment plans. This re-evaluation is integral to our planning approach and will be informed by the knowledge we will gain from greater depth in our data analysis, emerging clarity on the increasingly sophisticated transactions across our network, load growth patterns and changes in community expectations.

Managing our assets

Orion takes a proactive approach to managing our assets through extensive maintenance and replacement programmes. We believe a planned approach is in the long-term interests of our customers as it minimises outages, addresses assets on a risk basis and is more cost effective. A secondary advantage is that a consistent flow of work maintains the competencies of our people and service providers.

We reduce the impact of weather and plant failure events by conducting regular proactive programmes and approximately 70% of our network operational expenditure is spent on inspections, testing and vegetation management. The remaining 30% is spent on responding to service interruptions and emergencies, the majority of which occur on our overhead network and are largely weather related.

Our forecast increase in operational expenditure is due to a range of factors, including accelerating our pole replacement programme and increasing our focus on vegetation management.

For a list of our planned capital replacement programmes and maintenance programmes, see Tables 1.1 and 1.2.

Developing our network for the future

This AMP reflects a step-change in Orion's infrastructure capital investment programme for the next 10 years. In the immediate, transitional period we are developing our understanding of the potential impacts on the energy sector of the accelerated rate of decarbonisation and how the market will respond to new technology and changing customer expectations.

We have a rigorous process to evaluate opportunities and issues that may prompt network development programmes.

In our region, these impacts are expected to promote greater levels of demand growth over and above Orion's traditional growth driver of population increases which continues at strong levels.

Our top 10 network development base programmes are set out in Table 1.3. Eight out of ten of these programmes are to support growth by expanding our network capacity and increasing resilience. These programmes cater for the continued residential demand growth in developments in Selwyn townships and the southwest of Christchurch, and increase the resilience of our network through the Region A and B subtransmission programmes.

Two of these ten programmes support customer driven projects and our LV monitoring programme. These are important provisions to ensure our network is ready to help power the future needs of business in our region and the wider community.

In our planning we have taken into account a significant level of sector transformation by the end of this AMP's 10 year period. Our estimates for the increased expenditure that will be required are captured as part of this plan, beginning in FY24 and building to more than 75% of our planned network capital expenditure by the end of the 10 year period.

We have made high level allocations based on our best estimates of the direction and magnitude of the challenges and opportunities of the future as we work towards defining specific projects and programmes. A combination of engaging with our stakeholders and insight into the loading patterns of our network through data analytics, our LV monitoring programme and access to end-user meter data will enable us to refine this approach.

For more detail on our network development base programmes and the investment in our network to meet future needs, see Section 7.

Supporting our business

We are gearing up our business to meet the challenges and opportunities presented by a more connected and interactive energy future. Being more agile, efficient and responsive to our customers' changing expectations calls for new systems, processes, and capabilities. Orion is committed to making decisions informed by intelligent analysis of the data available to us, and ensuring our operations are performing as efficiently and effectively as possible.

For this reason, a key area of focus for Orion is upgrading and developing new systems and processes.

We are also focused on extending our use of data and digitisation to deepen our understanding of how customers are using our network. These insights will help us to optimize our business processes and network, inform system and platform development and engage in new ways with our customers. Our step-change in Orion's use of data and digitisation will deliver greater operational efficiency and better outcomes for our customers.

The changes we are making to adapt to the needs of the future, mean Orion's non-network operational expenditure is 1.5 times more than last year's forecast. This increase reflects increased expenditure on:

- system operations and network support team opex
- business support opex
- a range of data, digitisation systems that support operation of our network

For an overview of the teams, systems and processes we use to manage our network, see Section 8.

Compared to our previous AMP, our network spending is forecast to increase by 260% in capital expenditure and 140% in operating expenditure over the next 10 years.

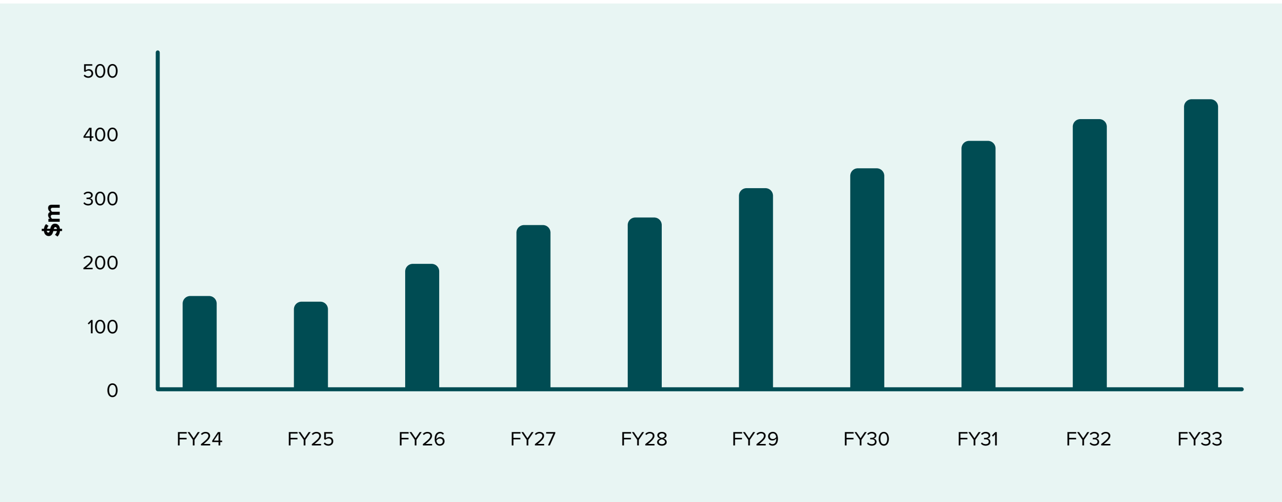
Financial forecast

Over the next 10 years we are forecasting total capital expenditure of $3b and operational expenditure of $1.2b. Compared to our previous AMP, our network spending is forecast to increase by 260% in capital expenditure and 140% in operating expenditure over the next 10 years.

Orion's role is crucial in Aotearoa New Zealand's pursuit of achieving net zero carbon emissions by 2050. To accomplish this, it is imperative that we prioritise the upgrading and strengthening of our electricity distribution network.

For our 10 year forecast of total network capital expenditure for this AMP period, see Figure 1.1.

Figure 1.1 Total capex forecast (real) – $000



Given the expansion of our asset base and the growing complexity of our operations, it is essential to increase our staff numbers, systems and training efforts. This is reflected in our forecast for non-network operational expenditure. Our network operational expenditure forecast includes provisions for the acquisition of flexibility services which aim to manage peak demand and avoid new network build; asset maintenance; and emergency response as well as accommodating our data storage and management requirements.

For our 10 year forecast of total network operational expenditure for this AMP period, see Figure 1.2.

Figure 1.2 Total opex forecast (real) – $000

Delivering our works programme

With the significantly increased programme of works we and the rest of New Zealand's electricity industry are anticipating in the next few years, there is sector-wide consensus that the industry workforce will need to increase and new capabilities developed.

More complexity in the distribution system will also call for greater expertise and new skills. This is likely to coincide with a time of increasing demand for skilled electricity workers internationally. We acknowledge it will be a challenge to adequately provide the skilled workforce to deliver our plan as our sector competes nationally and internationally for resources to deliver decarbonisation.

To address the challenge of delivering on our commitment to decarbonisation in the decades ahead, our sector recognises the need to develop new ways to grow our workforce's capability and size. For the Orion initiatives to build the capability of our people and the sector, and our approach to efficiently managing the delivery of our ambitious network investment programme, see Section 10.

In the following pages, Tables 1.1, 1.2 and 1.3, we provide a list of our key capital replacement and maintenance programmes, and the top 10 network development base programmes and their alignment with Orion Group Strategy and our Asset Management Objectives

Table 1.1 Capital replacement programmes and their Asset Management Objectives for FY24 to FY33

Orion Group Strategy:		**Powering a cleaner and brighter future with our community**									
		Facilitating decarbonisation and hosting capacity at lowest cost				**Investing to maintain our network**					
Asset class	Programme description	Sustainability and environment	Network security and power quality	Customer experience	Customer driven work	Network performance and PQ improvements	Resilience	Safety	Ongoing opex costs	Network lifecycle economics	Engineering alignment and future readiness
Overhead lines	Ongoing pole and conductor replacement, overhead to underground conversion and line switch replacement					✓	✓	✓			✓
Switchgear	This asset class replacement is driven by condition and risk	✓				✓		✓			✓
Underground	Replacement of cables and link boxes e.g. supply fuse relocation programme to remove legacy issues							✓			
Secondary systems	Work includes relay replacement, radio upgrades and fibre installation between zone substations. LV correction equipment upgrade to improve power quality							✓			✓
Transformers	Replacement of end of life power and distribution transformers					✓		✓	✓	✓	
Network property	Work includes kiosk and security fence upgrade, building security and integrity improvements etc.						✓	✓		✓	

Primary objective　Secondary objective

Table 1.2 Maintenance programmes and their Asset Management Objectives for FY24 to FY33

Orion Group Strategy:		**Powering a cleaner and brighter future with our community**									
		Facilitating decarbonisation and hosting capacity at lowest cost				**Investing to maintain our network**					
Asset class	Programme description	Sustainability and environment	Network security and power quality	Customer experience	Customer driven work	Network performance and PQ improvements	Resilience	Safety	Ongoing opex costs	Network lifecycle economics	Engineering alignment and future readiness
Overhead	Asset monitoring, inspections and maintenance. Emergency works					✓		✓		✓	
	Vegetation management					✓		✓			
Underground	Asset monitoring, inspections and maintenance. Emergency works					✓		✓		✓	
Secondary systems	Asset monitoring, inspections and maintenance					✓		✓		✓	
Primary plant	Asset monitoring, inspections and maintenance. Emergency works					✓		✓		✓	
Power transformers	Transformer refurbishment to ensure asset life is optimised	✓								✓	
Buildings, enclosures & grounds	Inspections and maintenance							✓		✓	

Primary objective

Secondary objective

Table 1.3 Top ten network development base programmes and their Asset Management Objectives for FY24 to FY33

Orion Group Strategy:		Powering a cleaner and brighter future with our community									
		Facilitating decarbonisation and hosting capacity at lowest cost				Investing to maintain our network					
Asset class	**Year(s)**	Sustainability and environment	Network security and power quality	Customer experience	Customer driven work	Network performance and PQ improvements	Resilience	Safety	Ongoing opex costs	Network lifecycle economics	Engineering alignment and future readiness
Region A 66kV subtransmission resilience	FY23 - 35	✓ (Secondary)	✓ (Secondary)				✓ (Primary)				✓ (Secondary)
Southwest Christchurch and surrounding areas' growth and resilience	FY24 - 32		✓ (Primary)				✓ (Secondary)				
Northern Christchurch network	FY26 - 28		✓ (Primary)				✓ (Secondary)				
Region B 66kV subtransmission capacity	FY22 - 28	✓ (Secondary)	✓ (Primary)				✓ (Secondary)				✓ (Secondary)
Customer driven projects	FY24 - 27	✓ (Secondary)			✓ (Primary)						
Lincoln area capacity and resilience improvement	FY23 - 29	✓ (Secondary)	✓ (Primary)		✓ (Secondary)		✓ (Secondary)				
Rolleston area capacity and resilience	FY24 - 33		✓ (Primary)				✓ (Secondary)				
Hororata GXP capacity and resilience	FY26 - 31		✓ (Secondary)				✓ (Primary)				✓ (Secondary)
LV monitoring programme	FY20 - 26		✓ (Secondary)				✓ (Primary)				✓ (Secondary)
Proactive LV reinforcement	FY24 - 33		✓ (Primary)		✓ (Secondary)		✓ (Secondary)				

Primary objective   Secondary objective

AMP section summary

This Asset Management Plan is divided into 10 Sections which cover:

Section 1: Executive summary

Our executive summary provides an overview of this Asset Management Plan. Here we reflect on the recent changes in Orion's environment and journey, outline the key influences and major factors and programmes of work that guide our approach to managing our assets for the next 10 years.

Section 2: Our strategy

We deliver electricity to more than 220,000 homes and businesses in Otautahi Christchurch and Central Canterbury. In this section we explain how our asset management programme is driven by our Group Strategy, and detail the factors in our environment that are driving our investment in Orion's network over the next 10 years, and the strategies we have elected in response to them.

Section 3: Managing risk

This section sets out our approach to managing the risks facing our business as a lifeline utility, and the diligence with which we approach risk management. We identify what our key risks are and how we go about risk identification, evaluation and treatment of these risks.

Section 4: Customer experience

Here we set out the different ways we listen to our customers and other stakeholders. Being close to our customers and keeping up with their changing needs is central to our asset investment decisions and asset management practices.

Section 4 details our customer engagement programme, and our performance against our service level targets for FY22 and our targets for the AMP period.

Section 5: Our planning

This section details the footprint and configuration of our network, and our asset management process. Here we explain how Orion uses a lifecycle asset management approach to govern our network assets. This process balances cost, performance and risk over the whole of an asset's life.

Section 6: Managing our assets

Here we provide an overview of each of our 18 asset classes; and outline an assessment of their asset health along with our maintenance and replacement plans for each one.

Section 7: Developing our network

In this section we set out how we are developing our network to prepare for the future. We discuss the changing demands on our infrastructure as we respond to the growing needs of our region and opportunities posed by the transition to low carbon energy. We describe the major Investments we plan to make in our high voltage (HV) network in the next 10 years and our LV investment approach.

Section 8: Supporting our business

This section provides an overview of the Orion teams who together, enable our business to function. It outlines the responsibilities of each team. It also describes organisational changes and other initiatives to support continuous improvement in operational efficiency and our focus on preparing for the future.

Section 9: Financial forecasting

Here we set out our key forecasts for expenditure for the next 10 years, based on programmes and projects detailed in Sections 6 and 7. In summary form, we set out our capital and operational expenditure for our network, and the business as a whole, annually from FY24 to FY33.

Section 10: Our ability to deliver

Our ability to deliver our AMP relies on an appropriate level of capable, experienced and skilled resource – both within the Orion team, and via our service providers.

For details of our key challenges and the policies and processes that enable us to deliver our works programme and AMP objectives, see this section.

If you would like to know more about our approach to managing our assets and our plans for the next 10 years, please contact us on 0800 363 9898, or by email at info@oriongroup.co.nz.

2 Our strategy

”The energy transition will require a dramatic increase in capital spending on the electric grid, delivered at an unprecedented pace… It is, arguably, a century of work to do in less than a decade”

McKinsey 2022

Photo: Network Development Manager Craig Wong in a planning session with the Network Transformation and Investment team.

Contents

2.1 Introduction

Central Canterbury is a place of rapid growth and transformation, embracing change and innovation, with Ōtautahi Christchurch at the heart of this diverse and vibrant region.

Electricity distribution has always been an essential service that underpins regional, community and economic wellbeing. Our service is vital to the wellbeing and livelihood of the people and businesses who live and operate here.

Now, it also has a critical part to play in New Zealand's transition to a low carbon economy. Challenges and opportunities are arising from a combination of our community's willingness to adopt changing technologies, Aotearoa New Zealand's drive for a low-carbon future, and the impact of climate change.

Sections 2.2 to 2.5 provide a brief overview of our business before summarising the challenges we face in the coming decades – each of which will have a significant effect on us – and our strategic approach to these factors.

Sections 2.6 through to 2.10 provide a more detailed overview of the environment in which we are operating, the impact of that on our forecasts, and ongoing challenges we have around such things as inflation and energy equity. In the latter part of the section, we set out the process we go through to develop our asset management plans.

While we face huge change in coming years and a rate of growth in demand for electricity which is unprecedented, Orion is confident it has the agility and capability to continue to serve its customers well, at lowest possible cost, in the evolving energy environment.

2.2 Orion today

We own and operate the electricity distribution infrastructure in Central Canterbury, including Ōtautahi Christchurch. Our network is both rural and urban and extends over 8,000 square kilometres from the Waimakariri River in the north to the Rakaia River in the south; from the Canterbury coast to Arthur's Pass. We deliver electricity to more than 220,000 homes and businesses and are New Zealand's third largest Electricity Distribution Business.

Orion has a fully owned subsidiary, industry service provider Connetics, and together with Orion the two organisations make up the Orion Group.

We deliver electricity to more than 220,000 homes and businesses and are New Zealand's third largest Electricity Distribution Business.

People and businesses continue to be drawn to settle in Central Canterbury, and strong growth in customer numbers continued with more than 4,300 new customers in FY23.

2.3 Our changing environment

Orion faces a rapidly changing and massively different energy environment in the decades ahead.

The changing landscape facing Orion is primarily driven by three factors – climate change, new technology and increasing demand for electricity. The increasing demand for electricity is driven by the need to enable decarbonisation at pace, and population growth.

While the move from petrol and diesel vehicles to electric vehicles is an important step on the decarbonisation journey, other initiatives will also make significant contributions. Of those, the largest contributors across Aotearoa New Zealand will be conversion of industrial processes and heating from coal to electricity and significant solar and wind generation.

Orion, along with Aotearoa New Zealand's other electricity distributors, has a key role to play in enabling decarbonisation and the electrification of the economy in service of New Zealand's target for net zero greenhouse gas emissions by 2050. However, the requirements/drivers for Orion are not the same as those for other distributors.

Different regions in New Zealand vary significantly in many ways:

- geography
- weather patterns, for example temperatures
- demographics, for example population growth and trends
- economic / planning imperatives such as housing intensification
- community needs for amenities, for example housing
- the energy transitions already experienced such as the switch to electricity for water and space heating
- how much latent capacity is currently available

This means each electricity distribution network in New Zealand is unique and requires their own, individual investment strategy. Some will need to invest more in high voltage systems, some more in low voltage, and some, like Orion, in both. Differing investment in data and digitisation of network management systems will also be needed. Opportunities to utilise customer load flexibility will also vary from network to network.

As a result, each New Zealand electricity network will require different levels and timing of investment.

... each electricity distribution network in New Zealand is unique and requires their own, individual investment strategy.

2.3.1 Drivers of network investment

The elements in our environment that are driving investment in our network are:

- **transport electrification** – Central Canterbury accounts for approximately 10% of the New Zealand vehicle fleet, and we expect around half a million vehicles will be fuelled by our network in the future
- **industrial conversion to electricity** – industry conversion is expected to add anywhere between 8% and 33% to our peak load by 2035
- **changing customer behaviour and expectations** – our customers are changing the way they use, generate, and manage their energy needs
- **low voltage network impact and approach** – the increasing complexity of energy flows across our network requires smart systems to optimise the energy throughput
- **loss of hot water control** – uncertainty about how hot water cylinders will be managed by the industry in the future means we may need to build our network bigger to cope with an additional 30MW of load by 2035
- **housing intensification and population growth** – more than 75% of residential growth in Ōtautahi Christchurch is now multi-unit dwellings which have a high cost to connect in established areas; and Selwyn District is New Zealand's fastest growing area
- **utility scale solar generation** – we currently have more than 600MW of utility scale solar generation being considered in network area. As context, our peak load is approximately 650MW
- **developing a smart grid** – transitioning to a future where two-way flow of power is seamlessly managed will require considerable effort and investment in smarter systems and controls
- **adapting to climate change** – climate change will result in increased investment in the overhead network and tree trimming, due to increased wind speeds and risk of fire, and increased costs due to sea level rise and increased air temperatures

Each of these elements impacting our transition to a low-carbon economy, presents challenges and opportunities, and for more detailed discussion and background, see Section 2.6.

2.3.2 Strategic approach adjusting to change

In Section 2.4 we set out our Orion Group Strategy to meet the challenges and opportunities of our changing environment. Our Purpose is to power a cleaner and brighter future with our community.

In service of our Purpose, our goals for Orion over the next five years are:

- facilitating decarbonisation at lowest cost
- investing to maintain a safe, secure and reliable network at lowest total lifecycle cost

We will put downwards pressure / drive costs down in four ways, by:

- **creating a more highly utilised network** – particularly at the low voltage level where our aim is to enable customer participation, prosumers, utilise new technology and information to squeeze as much as we can out of the existing network. If we achieve this, our back of the envelope analysis indicates we could have avoided in the order of $300 per customer per annum compared to other strategies / pathways
- **implementing a more efficient and effective works management system** – based on utilitising new technology and digitisation. Our back of the envelope analysis indicates we could avoid in the order of up to $6m per annum in costs if successful
- **using real time data and new technology such as drones to locate faults and restore power** where safe to do so, thereby avoiding the cost of truck rolls
- **optimal timing of asset renewals** – through improved processes and asset information. If successful, this initiative could potentially, over time, materially reduce total renewal capex potentially by up to 10% by mid 2030

The reason why these are our goals and why we are focusing on them, is that successfully implemented – albeit not all levers are within Orion's control – what customers pay for Orion's component of their power bill, will be hundreds of dollars less per annum than it they would be otherwise. At Orion we are very conscious of the need to balance the energy trilemma: **sustainability** – decarbonisation, **security** – climate adaptation and resilience and **affordability**.

In service of our Purpose, our goals for Orion over the next five years are:

- **facilitating decarbonisation at lowest cost**
- **investing to maintain a safe, secure and reliable network at lowest total lifecycle cost**

Our Purpose is to power a cleaner and brighter future with our community

2.4 Our Group Strategy

2.4.1 Our Group Purpose

Orion's Group Purpose of "Powering a cleaner and brighter future with our community" is central to all we do and is the touchstone for this AMP.

As New Zealand transitions to a low carbon economy, the energy sector has a critical part to play. Orion has established its Purpose to be a vital player in that transition for our community and our region. We are focused on helping our community realise its dreams for a future that is new, better, and more sustainable over the long term.

2.4.2 Our Group Strategy

While it remains critical for Orion to provide our community with confidence in their energy supply, we have also challenged ourselves to think about what a changed future holds, and how the Orion Group needs to assist the community it serves to proactively harness opportunities in a fast-changing energy landscape.

Refined in 2022, the Orion Group Strategy continues to be the cornerstone of our daily conversations and in our planning. While its scope is wider than our AMP, it is the driving force behind our network development and maintenance programmes and initiatives, and vision for the future.

Figure 2.4.1 Group Strategy framework

Purpose	Powering a cleaner and brighter future with our community				
Impact	Driving prosperity for our region through balancing energy affordability, energy security and sustainability				
Focus Areas	Facilitating decarbonisation and hosting capacity at lowest cost	Investing to maintain a safe, reliable, resilient network at lowest total lifecycle cost	Being a force for good in the communities we serve	Creating the preferred workplace	Fit for purpose capital structure

Orion Group is focused on ensuring we are ready to enable our community to transition to a low carbon economy.

Our Purpose – powering a cleaner and brighter future with our community talks to the impacts we want to make of regional prosperity through energy equity, energy security and sustainability.

Our priority for the next five years is to get 'match fit'. This means our network will be ready for the increased demand as electricity plays a crucial role in decarbonising Aotearoa New Zealand.

Our five year focus areas are:

- facilitating decarbonisation at the lowest cost while giving our customers choice on how they access our network
- investing to maintain a safe, reliable, resilient network at lowest total lifecycle cost
- being a force for good in the community, enabling a net zero transition
- our people are at the heart of what we do
- fit for purpose capital structure – funding our future to ensure our investments are sustainable and provide equitable returns to our shareholders

2.5 Our asset management strategy

Our asset management strategy translates our Group Strategy into asset investment drivers and asset management objectives at an operational level.

While all aspects of our Group Strategy touch on our network operations in various ways, of the five focus areas, facilitating decarbonisation and hosting capacity at lowest cost, and investing to maintain our network are the key drivers of our asset management strategy.

In Figure 2.5.1 we summarise the strategies we have adopted to respond to the factors driving changes in our environment and investment drivers. More detail on these strategies is contained elsewhere in this AMP, including in Section 2.6.

Figure 2.5.1 Our strategies aligned to investment drivers and focus areas

Powering a cleaner and brighter future with our community

Orion Group Strategy Focus Area	Investment Drivers	Strategy
Facilitating decarbonisation and hosting capacity at lowest cost	Transport electrification	**Lower demand** Encouraging customers to charge off-peak and utilise flexibility solutions and new technology
	Industrial conversion to electricity	**Just in time** Engage with industrial customers to ensure lowest cost solution is adopted when needed and not before
	Changing customer behaviour and expectations	**Customer participation** Explore flexibility solutions that help meet customer's energy needs
	Low voltage network impact and approach	**Release network capacity** Use data, digitalisation and technology to release currently inaccessible latent capacity
	Loss of hot water control	**Build bigger as a last resort** Build our network to meet anticipated increase in peak load
Investing to maintain our network	Housing intensification and population growth	**Keep up with growth** Reinforce supply in constrained areas only after all other options are explored
	Utility scale solar generation	**Ensure grid stability** Invest and monitor network impact to ensure stability
	Developing a smart grid	**Make our network smarter, more intuitive** Invest in a totally integrated, smart, intuitive electrical grid
	Adapting to climate change	**Build it stronger** Invest to meet the key climate risks we face

OUTCOMES (Facilitating decarbonisation and hosting capacity at lowest cost)

Maximise the scope for customer participation through 'flexibility' and other market-based solutions

Ensure our network enables thepath to decarbonisation

Maximise the use of the existing network with smart technologies and better data

OUTCOMES (Investing to maintain our network)

Be a responsible steward of the network and invest for the long-term

Drive cost effectiveness / efficiencyand continuous improvement / innovation in everything that we do

Leverage the power of integrated systems and data analytics

2.5.1 Approach independently affirmed

We are confident our asset management strategic approach will deliver the network our customers want and need, at lowest possible cost. That our approach is the correct one was affirmed by a report released in October 2022, by Boston Consulting Group (BCG), on the future of electricity in New Zealand: The Future is Electric – A Decarbonisation Roadmap for New Zealand's Electricity Sector. That report explored several pathways for how the sector could evolve to best contribute to the country's decarbonisation objectives. BCG's preferred lowest-cost pathway, 'smart system evolution', affirmed the direction Orion is taking.

The key challenges and solutions BCG identified are set out in Figure 2.5.2. Orion's asset management approach and current workstreams address all of BCG's proposed network solutions and targeted peak demand solutions.

BCG identified that one of the key solutions in the future is the need for demand side flexibility to balance the increasingly intermittent electricity supply. Orion has a good history of utilising demand side flexibility, and we have in the last few years developed several new work programmes to further improve our use of it. For more detail on these, see Section 5.

Orion's asset management approach and current workstreams address all of BCG's proposed network solutions and targeted peak demand solutions.

Figure 2.5.2 Solutions needed to address four challenges – Source BCG report

Future Changes	Energy System Changes	System solutions across the 4 challenges: 1 Renewable generation	2 Peak demand	3 Dry years	4 Network
Higher rates of electrification	Increased energy demand	More renewable generation development needed	Increased energy demand	Increased energy demand	More network infra. needed to enable renewable generation
	Greater peaks in demand profile	–	More flexible supply-side and demand- side capacity needed	–	More network infra. needed to enable electrification
	Increased need for resilience	–	Increased need for reserves to cover high impact, low probability events	–	More resilient transmission and distribution needed
More intermittent renewable generation	More variable and less predictable supply	Opportunity for renewable generation to be paired with storage to firm output	Flexible capacity increasingly needs to be fast-start to balance changes in system	–	Grid needs to dynamically balance supply and demand across system
Less thermal generation	New types of resources needed to meet peak capacity and dry year energy	–	More storage and demand-side flexible resources needed to help meet peaks	Renewable overbuild, demand response, and/or deep storage needed to help meet dry year energy	–
More distributed electricity system	Increased need for system smarts to integrate DER	–	Smarts needed to better coordinate DER to assist with meeting energy peak demand	–	Network smarts needed to enable significant increase in flexibility to reduce level of physical network infra-structure needed

2.6 Our drivers of investment

In this section, we describe what we anticipate will be the most significant drivers of new investment in Orion's network. These investment drivers underpin much of the expenditure we will undertake in the next decade, as covered by this AMP, and over the next three decades to 2050.

Ongoing 'business as usual' maintenance and renewal of our existing distribution network is, and will continue to be, a very significant driver of investment, however this is not discussed in this section as it is not a new driver of investment that needs to be highlighted.

While certain elements of New Zealand's transition path to a low emission, climate resilient future are well-understood and the timings established, for example the net zero by 2050 target and phasing out of coal boilers by 2037, the timing for other elements, such as the take up of electric vehicles or speed of industrial heat conversion, is still very uncertain.

Orion has made an educated assessment, supported wherever possible by customer insight, of what can be expected of our network. We recognise there are significant uncertainties and assumptions built into our forecasting. There is a risk that before flexibility and other markets and systems are mature, we will have high levels of housing intensification in Christchurch and lose the ability to manage hot water cylinders to keep peak demand on our network lower. These are both significant risks and we have allowed for them in our expenditure forecasts.

Our approach is to undertake least regrets actions over the next few years that will prove useful under all possible future scenarios. We also have a strong focus on building our understanding of evolving drivers of change in our region and emerging solutions, to support robust investment decisions which enable our customers affordable access to the energy services they require.

Over the next twelve months we will develop a more rigorous and structured set of demand forecast scenarios out to 2050. For this forecasting approach, see Section 5.

2.6.1 Transport electrification

Road transport accounts for more than 16% of New Zealand's carbon emissions. A 'mode shift' to grow the share of travel by public transport, walking and cycling, reducing the reliance on private vehicles, and the electrification of transport are critical to New Zealand achieving its net zero emissions target by 2050. While currently the number of electric vehicles (EVs) in New Zealand is low at around 1% of the total fleet, that number is predicted to accelerate dramatically in coming decades.

The impact of increasing numbers of EVs on electricity demand is highly uncertain, as it is subject to multiple factors including:

- number of EVs in a network area
- use of charging infrastructure – public infrastructure vs residential charging
- frequency and time of charging
- kW rate of charging

We are confident the potential impact of EVs on peak demand can be managed by effectively encouraging owners to charge their EVs during off-peak hours.

With current takeup at low levels, it remains unclear how much an electricity network's peak demand will change because of EVs. Networks in Great Britain typically assume each EV will add between 1.5kW to 2.5kW to peak on their high voltage networks. Networks in New Zealand also appear to be assuming a broad range from around 1kW to 3kW.

Translated to the 100,000 to 300,000 EVs various government departments and crown entities are forecasting to be on Orion's region's roads by 2033 the kW impact per EV scales up to a total increase in peak demand of somewhere between 100MW and 900MW. By comparison, our current network peak, in winter, is around 650MW.

Orion's view is that the increase in peak will be less than most other networks are assuming – we consider it may be possible for us to achieve as low as 0.5kW per EV network-wide peak impact. Localised impacts at the low voltage level may be significantly higher than 0.5kW per EV, depending on the number of EVs on a street LV feeder.

We are confident the potential impact of EVs on peak demand can be managed by effectively encouraging owners to charge their EVs during off-peak hours. We are exploring various ways to achieve this, principal among them is pricing that encourages charging of EVs overnight. Worldwide, the commonly accepted way is through time-of-use pricing. Many networks and retailers in New Zealand are shifting to time-of-use pricing. In our future pricing strategy, Orion will refine our time-of-use rates, which have been in place for more than 20 years, further to provide EV owners with increased incentives to minimise impact on our network.

In addition to utilising pricing to ensure peak demand increase is minimised, we are also exploring other low-cost measures that will help transport electrification to be achieved at lowest cost to our customers. Additional measures include increased engagement and education of customers and key transport stakeholders, and the use of flexibility services offered by third parties such as electricity retailers.

2.6.2 Housing intensification and population growth

The cost to upgrade electricity infrastructure to service housing intensification in established residential areas is significantly greater than the cost to rollout new infrastructure to service new residential developments.

The incidence of housing intensification is growing in Orion's region, as it is nationally. Christchurch City Council (CCC) says multi-unit dwellings made up around 44% of residential consents in 2016. This figure has steadily increased to around 75% in 2022. We expect this figure to continue to increase given recent changes to government policy that encourages more intensive housing to avoid urban sprawl and increase housing supply in urban areas.

As housing intensifies and EV uptake increases, the spare capacity in Orion's low voltage network will diminish. As explained in Section 2.6.3, we plan to use up as much of this spare capacity as possible, before we trigger other methods to meet the increased demand need. Through managed release of currently latent and unused capacity we will be able to reduce our costs below what they otherwise would be. However, in some areas as growth continues, we will eventually reach a tipping point where Orion needs to either utilise flexibility solutions or invest in LV and potentially medium voltage network reinforcement in areas that have reached capacity.

More generally, significant growth in customer numbers is occurring. We continue to connect more than 4,000 new customers per year and this strong growth in connections to our network shows no signs of tailing off in the medium to long term.

Historically, population growth forecasts from Government and local councils have dramatically underestimated actual population growth. For example Selwyn District Council, as part of its long-term development plan, forecast Rolleston's population would reach 26,500 in 2028. It reached 28,000 in June 2022. This strong residential growth in New Zealand's fastest growing district, combined with major decarbonisation efforts at the nearby Burnham Military Camp, means Orion is required to invest more than $20m in the next two years to reinforce supply to the Rolleston area. There are also several other areas in our region where population growth is driving an increase in network investment.

2.6.3 Low voltage network impact and approach

Our investment strategy for our LV network is to use new information and technology to optimise the throughput of energy across our existing network. We aim to only undertake traditional reinforcement when it is the most cost-effective option or when optimised networks reach capacity.

To achieve this, we will use smart systems to assess our low voltage network's electrical flows down to LV feeder level. Critical to achieving this is our ability to capture data on our low voltage network. Some of this data will come from equipment we put into the field such as low volage power monitors. Some will be from third parties such as data from smart meters located in homes and businesses. For more information on these sources of data, see Section 5.3. Using that data, we will utilise systems that can dynamically alter the loadings on these feeders to increase their usable capacity.

Through such smart new technology we will release currently latent and unused capacity from the network and optimise the utilisation of an existing feeder – more than has been possible historically. That released network capacity can then be used to connect more EVs and more new housing, without building new, expensive network.

We will also use other methods to ensure new low voltage network isn't unnecessarily built, including:

- increasing the maturity of our future energy scenarios and modelling capability to improve our confidence in future demand, flexibility, and network constraints to enable more timely interventions
- incentivising our customers and communities to help alleviate network constraints through the use of energy storage and demand side flexibility – where lower cost than network augmentation
- encouraging the best use of vehicle-to-grid and vehicle-to-home technology for electric vehicles to lower network peaks or solve other network constraints such as voltage issues
- using non-traditional network solutions, like Statcoms for voltage regulation, as a lower cost solution to traditional capacity upgrades

Through a combination of approaches, we will get the most out of our assets. We believe this low voltage strategy strikes the correct balance between risk and reward – where reward is lower cost to our customers. Other possible approaches would result in significantly higher costs for our customers without sufficient upside to justify. These are:

- preservation of existing levels of latent capacity, where we effectively keep on building a little more network at a time to maintain our current capacity buffer, where we have it, just in case something else new and unexpected comes along, or
- where we don't have any existing latent capacity now, we expand/reinforce en-mass in advance of potential increased demand

As housing intensifies and EV uptake increases, the spare capacity in Orion's low voltage network will diminish.

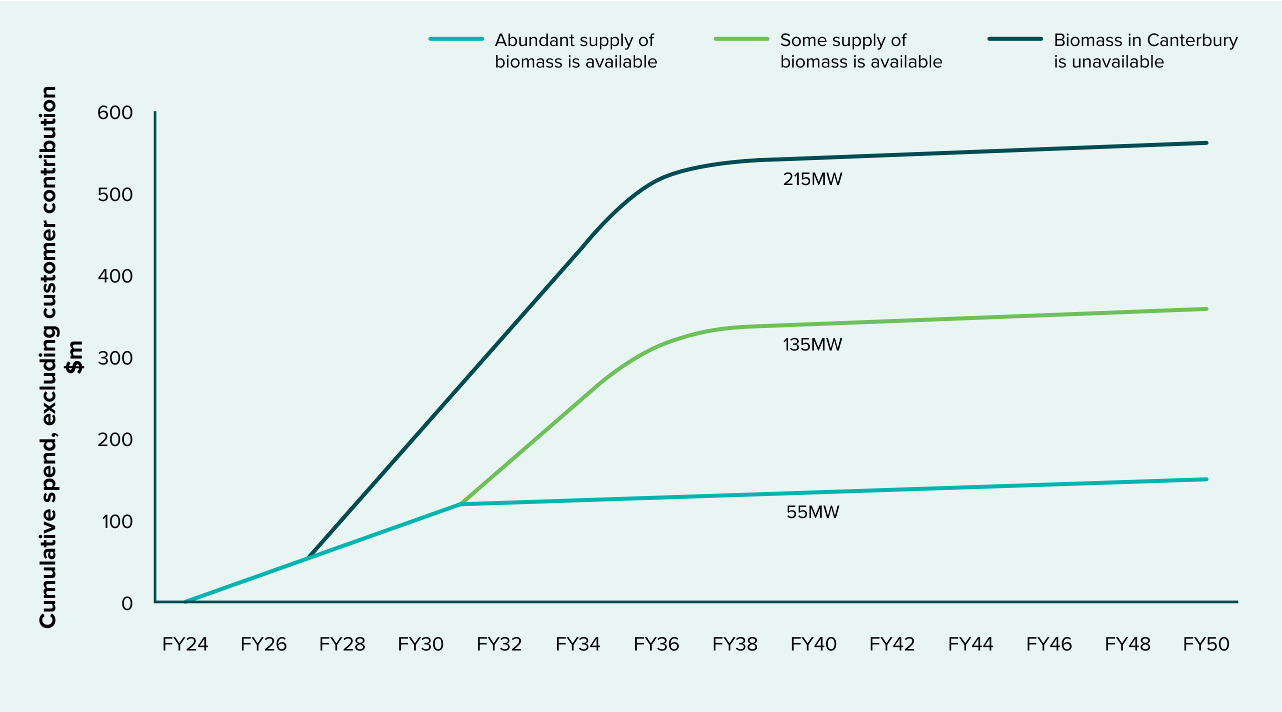
2.6.4 Industrial conversion to electricity

Based on recent national surveys, the amount of carbon emitting energy used by industry that will be converted to electricity in the next 15 years is disproportionally higher in Orion's network area compared to the rest of New Zealand. Orion can expect a significant uplift in electricity demand from industry compared to most other parts of New Zealand.

Surveys we have led in partnership with others show we can expect industry conversion, primarily due to decarbonisation efforts, to add peak load of between 8% (55MW) to 33% (215MW) to our current maximum peak demand. The significant range of uncertainty as to how much load will be added is due to the uncertainty around the availability and cost of biomass as a zero carbon alternative to electricity in our network area.

Orion can expect a significant uplift in electricity demand from industry compared to most other parts of New Zealand.

Figure 2.6.1 Indication of network spend under different biomass availability scenarios, excluding customer contributions



In this AMP, our forecasts are based on a mid-point being converted – 135MW or around a 20% increase to our current peak demand (~650MW). This 135MW broadly assumes dairy processing will not be able to convert to biomass, but all other industry will convert to biomass where it would be the first choice of fuel for that industry.

In relation to how we build network for this new industrial load, we broadly have two choices:

- wait until customers advise us of their soon to occur conversion, and then build quickly, or
- build quickly now, and have ample spare capacity on our high voltage network until the customer(s) actually convert to electricity.

Our approach will be the first of the two. Aside from reducing the possibility of over building, it also means that the costs associated with industrial conversion to electricity will fall primarily on the shoulders of the businesses converting their processes, rather than being socialised across all our customers. We believe this is fairer and more equitable.

For those industries that will be needing to pay for conversion, to ensure the customer cost of adding this new load is kept as low as possible, while enabling commercial and industrial customers to achieve their business objectives, we are engaging with business owners to find the best pathway for them to convert – be it to electricity, biomass, or some other clean fuel system.

The customer cost also may be lowered if government GIDI funding for industrial conversion can be utilised for electrical works.

2.6.5 Utility scale solar generation

Over the period of this plan, short of a government subsidy we do not expect residential solar PV systems exporting generated electricity back into our grid to cause Orion significant issues.

Solar embedded on industrial premises may increase at a greater rate than residential units, and will require some investment by us to monitor and predict solar production and be ready to supply the industrial customer with increased load when a cloud passes over.

Utility scale solar generation, namely PV farms that can be up to 100's of MW in size, will though require by far the greatest investment by Orion. Like with process heat, the marginal cost of connecting these solar farms will fall on the solar farm itself, rather than on say domestic households, however we need to include the total investment in our forecasts to ensure we are ready to deliver it.

The investment we will need to make is primarily related to two factors:

- **Whether the electricity the solar farm is producing can be safely fed into our network or Transpower's** – solar farms that are generating electricity but not consuming it on site may require significant upgrade of our network depending on the location. Systems to monitor the real time energy flows are also needed to ensure assets are operated within their capabilities.
- **Monitoring output and voltage impacts of the solar fed into our network** – we may need to lower the voltage on the line to ensure it stays within regulatory limits. We may do this using voltage stabilisation technology or flexibility solutions from customer owned batteries.

We currently have more than 680MW of utility scale solar generation being considered in Orion's network area. As context, we have around 25MW of residential solar connected with residential solar growth being around 7MW last year.

2.6.6 Changing customer behaviour and expectations

Our customers are changing the way they use, generate, and manage energy. This change is driven by a combination of factors, including the availability of technology that provides customers with options and control; increasing efforts to reduce carbon emissions; and the strong desire by customers to reduce their total energy costs. Since electricity will be the primary energy source of the future, Orion has a responsibility to help facilitate these changes and empower our customers to achieve their goals.

New smart technologies like automation, artificial intelligence, real-time communication, and home energy management systems are forecast to revolutionise the way electricity systems are operated.

This provides a significant opportunity to increase consumer participation in new emerging energy markets, the energy security of our community, and more effectively manage complex multi-directional electricity flows that will emerge in future.

We currently have more than 680MW of utility scale solar generation being considered in Orion's network area.

This concept, which is closely tied to what is known within the industry as enabling customers to participate in flexibility markets, is a critical part of Orion's strategy to deliver decarbonisation at lowest cost to our customer. Flexibility can be described as providing incentives and signals, such as time-of-use pricing, financial payments, or carbon signals, to customers to encourage them to alter their electricity usage patterns to either lower peak loads on networks or provide other valuable services to the electricity system.

For more information on our efforts to encourage and enable flexibility and customer participation in electricity markets, see Section 5.

Utility scale solar and large scale energy storage systems present opportunities to dynamically manage our subtransmission and high capacity distribution regions of our network, potentially enabling hosting of load beyond our traditional fixed asset capability. Because of the intermittency of renewable energy sources we are exploring ways to use risk based planning and operating criteria to enable current security margins to be used to help enable more renewable energy to be located in our network area. In FY23, we began publishing congestion maps for load hosting at the zone substation level on our website, and put in place a programme to improve transparency of information for customers, including generation hosting and DER support opportunities.

By investing in a robust, secure and intuitive grid, Orion will deliver modern and innovative electricity services our customers can benefit from.

2.6.7 Developing a smart grid

Transitioning to a future where customers can participate in electricity markets, where lower cost alternatives to network build are enabled, where two-way flow of power is seamlessly managed, and where the network is operated efficiently and utilisation is maximised, will require considerable effort and investment in smarter systems and controls. This will be particularly so for LV networks where the needs and impacts will be most severe and where historically the visibility, controllability, and flexibility has been weakest due to a lack of need.

Our objective is to act as a neutral facilitator to enable competitive access to markets and optimal use of energy resources on the network.

To achieve our objective, we are working towards a totally integrated, smart electrical grid. Several types of improvements in our systems are included in the period of this AMP, including:

- introducing digital platforms that reduce the cost and improve the efficiency and effectiveness of our core network operations
- enhancing our network monitoring such as installing low voltage monitoring equipment on our transformers and feeders, and analysis of smart meter network data
- improving network condition and utilisation monitoring
- communicating/interfacing with customer owned equipment, such as batteries and EVs
- deterministic and probabilistic modelling
- implementing dynamic operating systems
- enhancing our Advanced Distribution Management System (ADMS) to enable improved grid efficiency and resiliency to allow us to remotely respond to outages and other grid conditions quickly and safely

By investing in a robust, secure and intuitive grid, Orion will deliver modern and innovative electricity services our customers can benefit from.

2.6.8 Loss of hot water control

One long standing way Orion reduces our peak loads is through financial encouragement for residential customers to only heat their hot water cylinder overnight or to allow us to briefly stop them from heating their cylinder when we are experiencing peak demand conditions. We estimate our peak load is reduced by around 150MW from this intervention. Without this, our peak load would increase from around 650MW to 800MW – around 15% more.

Currently hot water control is achieved through Orion owned ripple control plant. Ripple systems are a cheap and effective means to control network and transmission peaks, however they don't easily allow an individual retailer the flexibility to reduce the hot water load of their customers when that individual retailer may want it to occur, any time of year. Consequently, it is likely that in the future many customers' hot water load will switch from being operated by ripple plant to being operated by technology within the customer's smart meter. This will then allow the hot water system to be more easily controlled for purposes other than network demand management, such as when it's most financially rewarding for the customer and/or the customer's retailer from a market price perspective.

...in this AMP, we assume Orion will need to build for an increase in peak load of 31MW by 2035, directly due to the loss of control of hot water from approximately FY27.

For most periods of time there is likely to be alignment between the desire to control hot water by retailers and distributors. However, there will be times when this is not the case. This means that unless regulations establish some sort of priority order for management of hot water via smart meters, on cold winter days we are unlikely to be able to reliably draw on all available hot water systems to reduce our peaks as retailers may want to control them at different times that day.

Consequently, there is a risk of peak network demand increasing because of system-wide energy management changes. This means our network will need to be built bigger.

We will engage with regulators on this issue to try to ensure the development of flexibility markets does not sacrifice the benefits in place already with the current hot water load control mechanism.

As regulatory success is uncertain, in this AMP we assume Orion will need to build our network for an increase in peak load of 31MW by 2035, directly due to the loss of control of hot water from approximately FY27.

For more details see Section 5.3.

2.6.9 Adapting to climate change

Extreme weather events caused by climate change mean our infrastructure must become more resilient and provide alternative solutions for customer and community energy resilience. Our report, Climate Change Opportunities and Risks for Orion provides our community with an understanding of how climate change might impact our business, and what we are doing to prepare for the future.

The initial impacts of climate change are that our network will experience more frequent and more intense windstorms and drier conditions increasing the risk of fire.

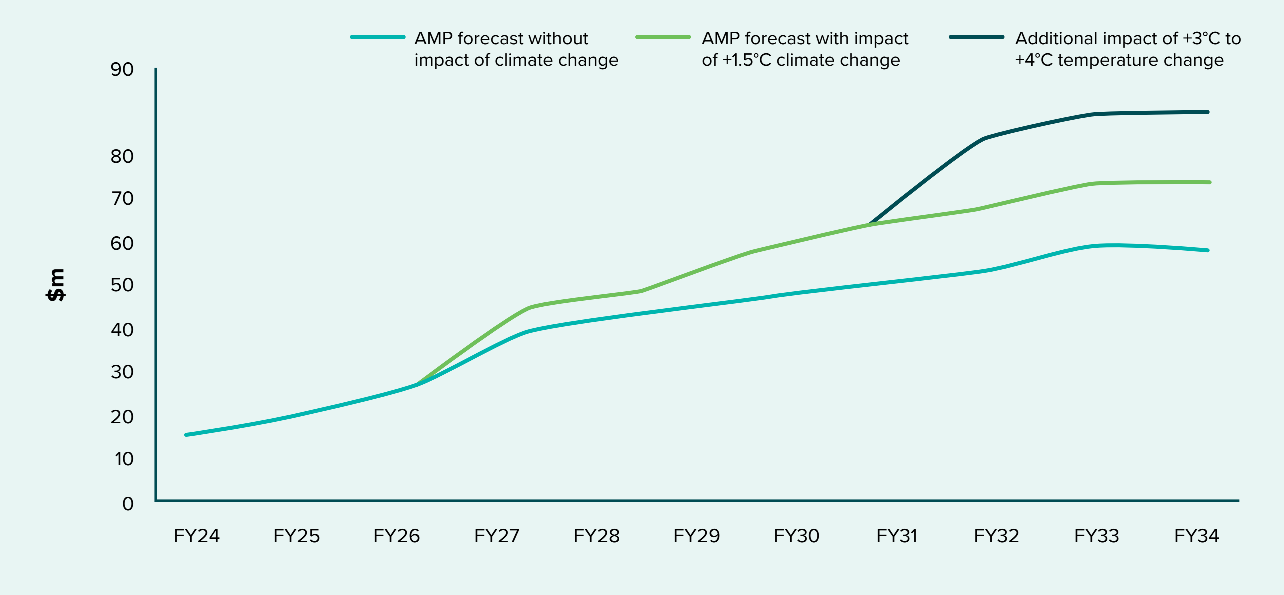
To prepare for the increased wind and fire risks associated with a 1.5°C temperature rise – consistent with the Government's emissions targets – we will need to increase the resilience of our overhead network. To do this we will:

- replace end-of-life poles with more resilient designs that are fit for the future. This reduces the long term cost impact of climate change and our recently improved condition based assessment work has identified a step change in the number of end-of-life poles needing replacement from 2027
- upgrade the resiliency of poles that have been identified as at high risk of wind/fire damage, but which aren't at the end of their life, in the lowest cost manner
- increase our vegetation management programme to reduce the incidence of trees damaging our network, particularly in windstorms
- replace more of our higher altitude poles

This lowest cost approach to adapting to climate change results in increased investment in our overhead network being forecast in this AMP. See Figure 2.6.2.

Unfortunately, the latest climate change research indicates it is increasingly unlikely temperature change will be kept to +1.5°C. Consequently, we are reviewing what changes would need to be made to our overhead design standard if temperature change was +3°C to +4°C. For the potential expenditure impact of this, which is not included in this AMP's forecast, see Figure 2.6.2.

Figure 2.6.2 Overhead capex forecast with climate change impacts



In the longer-term, as the EDB servicing New Zealand's second largest city with much of our customer base living near the coast, sea-level rise will affect the planning, maintenance and replacement of our assets.

Higher temperatures will also impact the performance of some of our equipment.

To date, these longer-term effects of climate change have not been included in this AMP. We are currently examining their potential impact and will include the associated costs in a future AMP. Orion is likely to take a probabilistic approach to inclusion of some of these costs as some impacts of sea level rise on our community may or may not eventuate. This depends on the Government and Christchurch City Council's position on managed retreat versus mitigation such as building sea walls.

In addition to reinforcing existing network assets and designs, decentralised designs are being considered as a complementary solution to reduce reliance on a central point of failure. Microgrids and other distributed energy resources may be an important tool for some communities to reduce the risk posed by climate change. As an example of what the future holds, we may have large containerised relocatable batteries being used in one area in winter to lower network peaks, and defer investment, before those batteries are shifted to another community in spring/summer to provide increased protection from wind-storms and fire. Orion will work with communities on this. See Section 5.6.1.2.

2.7 The changing environment's impact on expenditure

Electrification of transport, industry and other activities cannot be achieved without significant investment across the electricity sector. All the additional electricity needed in the decades ahead must lead to increased generation, transmission and distribution spend – although in the long-term most consumers will benefit from total energy cost savings across all aspects of their energy use.

The Boston Consulting Group (BCG) report, The Future is Electric – A Decarbonisation Roadmap for New Zealand's Electricity Sector, released in October 2022, stated that distribution spend in New Zealand would need to increase significantly and that distribution sector spend through to 2030 would be more than 50% of the total investment required in the entire electricity industry.

Internationally, forecasters are also expecting a significant uplift in distribution network spend. The International Energy Agency stated in 2020: "Electricity networks are the backbone of today's power systems and they become even more important in clean energy transitions… Significant investments in these networks will be essential in the coming years".

The BCG spend estimate broadly aligns with Orion's forecasts. However, the unique aspects of Orion's service region mean we estimate our investments will need to be made at a slightly faster rate. These unique aspects include the greater than NZ average industrial process heat impact; greater impact of the loss of hot water control as Orion has more current volume than most other EDBs; and potentially greater need for adaptation to climate change impacts.

When considering investment cost profiles, we also appreciate decarbonisation occurs at the rate our community wants, and Orion may need to make some investments earlier than under normal operating conditions. A 'just in time' investment approach is not appropriate when faced with considerable uncertainty on the speed and quantum of many growth factors and social pressure to decarbonise at pace.

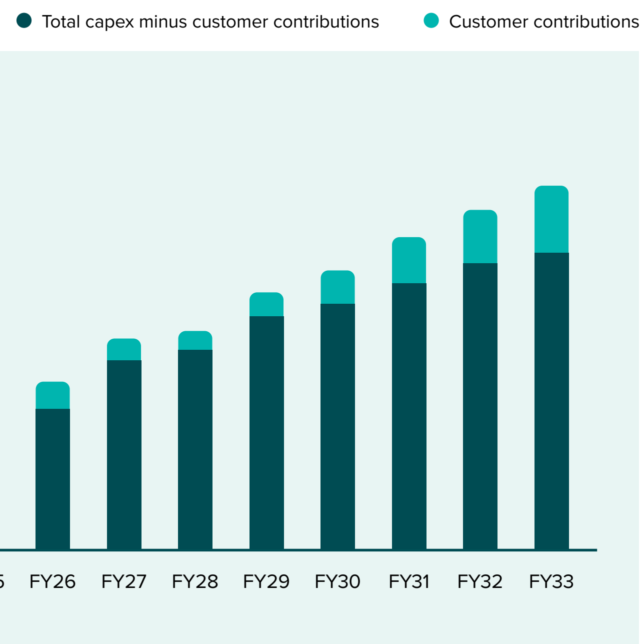
It is clear the imperative to decarbonise and deliver new services has large cost implications.

For the profile of our forecast capital expenditure over the next ten years, compared to the previous five years, see Figure 2.7.1. We have separately identified the expenditure that will be borne by the individual customer as a result of industrial heat conversion or utility scale solar farms, as opposed to the expenditure borne by our wider customer base. These have been identified as customer contributions in Figure 2.7.1.

It is clear the imperative to decarbonise and deliver new services has large cost implications. These expenditure impacts occur despite our objective to actively manage demand and unlock new value from customer owned equipment and exert downward price pressure on our costs.

The Commerce Commission sets the revenue EDBs can collect to recover expenditure through a default price-quality path (DPP) for distributors such as Orion that are subject to price-quality regulation.

Figure 2.7.1 Total capex actuals and forecast (real) – $000



2.7.1 Additional factors impacting on operating expenditure

The environmental drivers for our forecast increase in capital expenditure are set out in Section 2.6. In addition, there are operational and logistical factors included in our forecast expenditure increases. Here we outline the most significant of those factors.

2.7.1.1 Replacement of legacy assets

We are increasing our asset renewals budget by around 170% over the next ten years to replace legacy assets that were installed in the 1960s to 1980s. This is a function of the fact that as a network grows, so too does the size of the job to replace it in later years.

However, we are looking at a combination of asset management strategies to ease the pressure on costs. For example:

- **digitise asset data** – utilising more asset condition and inspection results to inform our asset investment decisions
- **risk-based management** – prioritising the renewal of assets that pose the greatest risk to compromising our service levels
- **Integrated Asset Management platform** – implementing a more efficient and effective works management system and processes
- **invest in technology** – the Automated Power Restoration System (APRS) which will be fully functional in FY24 will optimise network performance from ageing assets while we continue to work through the renewal programme

2.7.1.2 Increased tree trimming costs

We face increasing tree trimming costs, partly due to the elevated risk of fire from dry years and strong winds because of climate change. This work also supports reliability for our rural customers.

2.7.1.3 Increased business support costs

As the size of our asset base increases, and the complexity of our operations amplifies, we will also need to grow our employee numbers and business support budgets. To estimate this growth, we have examined the likely size of our business in each of the next ten years, investigated the business support costs of other EDBs of similar size. We have then applied an efficiency factor to recognise that as we invest in data and digitisation, and improved business processes, efficiencies will result.

Our step-change in Orion's use of data and digitisation will deliver greater operational efficiency and better outcomes for our customers.

Some allowance within business support costs is made for flexibility rewards paid to customers. Flexibility rewards is the payment of monies to customers for services to enable us to utilise the equipment they own or encourage them to shift load to maintain the system balance that is needed. These rewards, classified as operating expenditure, will be at lower cost than the alternative capital expenditure solution of building more network.

2.7.1.4 Data and digitisation

Being more agile and responsive to our customers' changing needs calls for systems and operational processes that enable Orion to make decisions informed by intelligent analysis of the data available to us, and operate to maximum efficiency.

A key area of focus for Orion is upgrading and developing new systems and processes and this plan reflects significant investment to lift our asset management platforms and customer management tools to state of the art levels.

We are also focused on extending our use of data and digitisation to deepen our understanding of how customers are using our network. These insights will help us to optimize our business processes, inform system and platform development and engage in new ways with our customers. Our step-change in Orion's use of data and digitisation will deliver greater operational efficiency and better outcomes for our customers.

For detail on our planned data and digitisation developments see Section 8.6.

For the profile of our forecast operating expenditure spend over the next ten years, compared to the previous five years, see Figure 2.7.2.

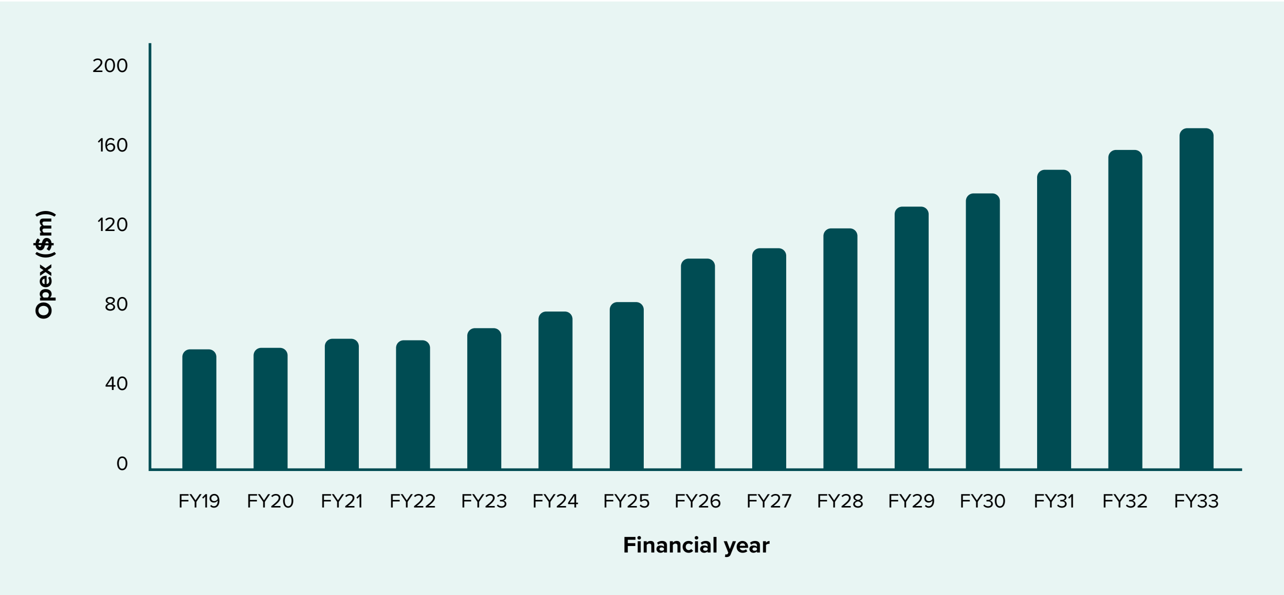
Our spending is forecast to increase by 260% in capital expenditure and 140% in operating expenditure over the next 10 years.

Sections 5, 7 and 8 provide further detail on the investment drivers, assumptions, planning strategy, rationale and projects we need to undertake over the next ten years, as well as the business support required to deliver our programmes.

As our scenario-based forecasting develops over the next year, and as we continue to examine further some of the emerging issues and enhance our discussions with customers, particularly industrial process heat customers, we plan for updated and refined forecasts for our 2024 AMP. Our scenario-based forecasting will underpin our ability to undertake least regrets actions at the right time and place, in service of our goals of community decarbonisation and delivering our customers the service they want at lowest possible cost.

Our spending is forecast to increase by 260% in capital expenditure and 140% in operating expenditure over the next 10 years.

Figure 2.7.2 Historic and forecast total annual operating expenditure (real) – $000



2.8 Potential supply chain cost escalation

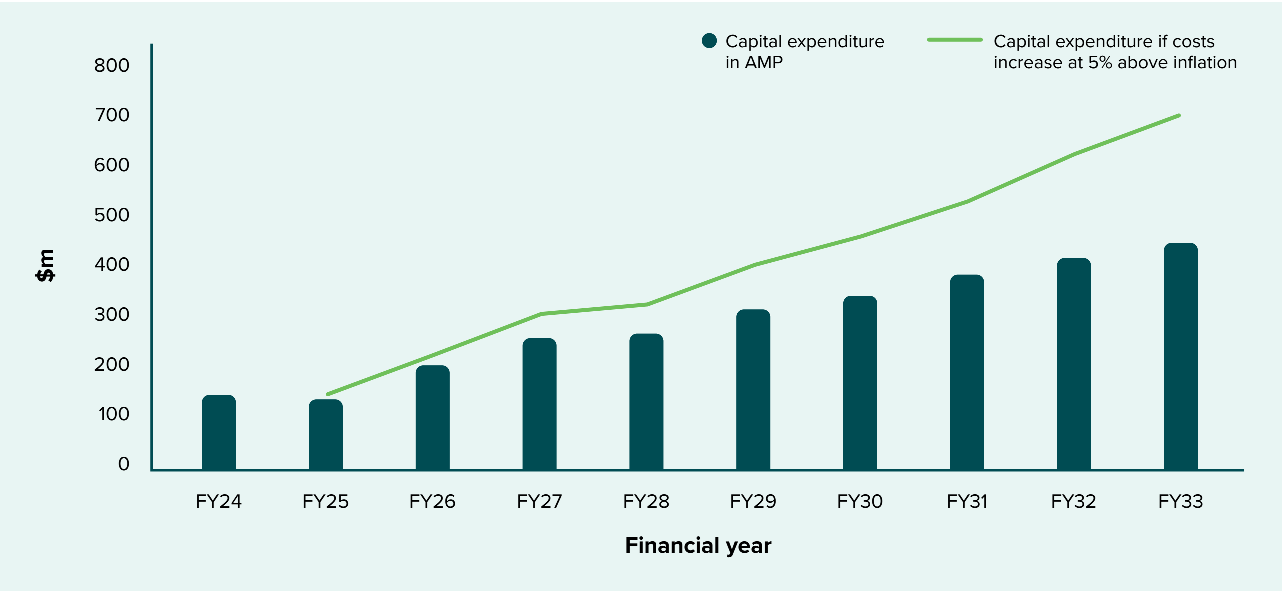
Supply chain issues and other costs have increased at a greater rate than either the consumer, labour or producer price indices. For example, over FY23 we estimate the total cost of project works tendered increased by 23%. Over the previous two years, the cost of installing a power pole increased by more than 40%.

In FY24 we forecast an increase in costs for project delivery of 12% – approximately 8% above the inflation rate forecast for that year. Beyond that we assume costs stay in line with Consumer Price Index (CPI). We will revisit and review this assumption in the next AMP.

For illustrative purposes, we show in Figure 2.8.1 how much our capital expenditure forecasts would increase if we had assumed electricity sector cost inflation of 5% per annum above CPI for the entire AMP period. This has not been included in current budget forecasts.

The impact of compounding interest rapidly results in much higher costs, with costs over the period FY26 to FY30 increasing from $1.46bn to $1.8bn. It becomes clear that being able to deliver our project plan in a timely manner is important to contain costs – and having the skilled workforce available to do so is critical.

Figure 2.8.1 Potential impact of supply chain cost inflation on capital expenditure (real) – $000



2.9 Energy equity and deliverability

Our expenditure forecasts are our best current understanding of the cost to deliver our network transformation programme to support decarbonisation and how our community will want to manage their energy needs. Two fundamental challenges remain to be addressed: the impact of increased prices on a community already struggling with energy equity, and deliverability.

2.9.1 Energy equity

The system wide investment required to enable decarbonisation may mean network companies and other industry players will need to escalate their prices at rates not seen in recent times.

We recognise many of our customers are already facing energy hardship, and further price rises, before the longer-term benefits of decarbonisation are realised more broadly, will deepen that hardship. This customer impact will not be limited to Orion customers alone. Without compensating measures to address it, in future years

We recognise many of our customers are already facing energy hardship, and further price rises, before the longer-term benefits of decarbonisation are realised, will deepen that hardship.

there is likely to be increased energy hardship for many New Zealanders, and energy equity issues will intensify.

Our regulators and the Government have some difficult calls to make on how the dilemma of needing to achieve decarbonisation but not deepen economic struggles is addressed. This balancing act will not be easy to achieve as energy hardship is a complex issue.

As with all complex issues, the solution will not come from one initiative and a 'one size fits all' policy will not be optimal. Rather a system-wide, multi-faceted, approach is needed.

We are committed to being a force for good in the communities we serve – it is a key element of Orion Group's strategy to deliver on our Purpose. Towards achieving this we are partnering with community groups such as Community Energy Action and engaging with our customers to address energy equity and community resilience. We wish to do our part in addressing the issue, and welcome discussions with regulators and the Government on the best way we can together tackle energy pricing and equity.

2.9.2 Deliverability

Deliverability of projects on-time and at forecast cost is an infrastructure project management and construction challenge for all EDBs. There is a lack of skilled workers available to undertake the work currently scheduled. In addition, the large increase in electricity projects that need to occur in coming years creates concern not enough skilled workers will be available to deliver the initiatives needed to occur to decarbonise the economy.

Concerns about the workforce capacity to deliver the projects forecast, the issue of deliverability and workforce size also has a knock-on effect: cost escalation.

As a result, Orion considers a key issue is how to ensure our service providers and Orion have enough trained and competent employees to enable the transition. Through our Energy Academy initiative and industry forums, we are in discussion with service providers, industry training bodies, and other electricity sector players, to determine what is needed.

For further discussion on deliverability, see Section 10.

2.10 Opportunities and innovation

2.10.1 Opportunities

Any change of the magnitude the electricity system is undergoing creates opportunities as well as challenges.

Orion is alert to the immense range of opportunities open to us and our community from the system, climate, social and technology changes we are undergoing, and will capture the greatest opportunities in our planning.

Opportunities afforded by the new era in electricity include:

- chance to update aging, equipment with modern, more efficient, and intelligent infrastructure
- opportunity to streamline systems and processes
- ability to introduce efficiencies
- better informed decision making
- faster analysis of immediate and longer-term situations
- increased sustainability and reliability
- improving the resilience of our network, and community
- ability to reduce costs in some areas
- chance to provide customers with more choice and flexibility
- the opportunity to empower our customers to manage their own needs, lifestyle choices
- provides employment opportunities in a growth industry
- innovation and adaptation are stimulated
- fosters new startup businesses

2.10.2 Innovation

Innovation is critical to ensure our customers' needs are met efficiently and cost effectively as the energy system rapidly evolves over the coming years. Innovation is part of our *DNA*.

Increasing complexity in the energy sector has amplified the need to 'learn-by-doing' and collaborate across the sector. We actively collaborate with others to explore challenges and opportunities in the sector through industry forums and participation in industry working groups. We also join with industry counterparts to commission industry analysis and whole-of-sector reports from global and local consultants such as the Boston Consulting Group. With our culture of continuous improvement and innovation, we also actively look for new and better ways to do things in our day-to-day operations.

During the past year we have made significant innovations and improvements, including:

- Developed the Orion **Network Transformation Roadmap**.
- Developed an **Innovation Pipeline** to enhance our ability to tackle challenges and opportunities in new ways.
- Powered by Orion Group & Ministry of Awesome, we ran the second **Orion Energy Accelerator** programme which supported 10 high impact energy innovations to help New Zealand move towards a carbon neutral future.
- Launched the **LUMO Global Energy Quest**, designed to build a culture of collaboration and innovation across the energy sector globally. With the support of EECA, Ara Ake and BusinessNZ Energy Council.

- Partnered with **Ministry of Social Development** (MSD) to explore opportunities for people to join the energy sector over the next few years.
- Launched an enhanced text and email **Outage Notification** service to alert customers to planned outages and any updates to timings.
- Refreshed our **Orion Group Strategy** to ensure our focus on current community needs and outcomes.
- Initiated our first trial of **flexibility services** as an alternative to network build in fast growing Lincoln township.
- Equipped and trained our rural operators with **drones** for more efficient and safer line surveys post outages.
- Launched **Snap Send Solve** for reporting of damage and graffiti on Orion Infrastructure.
- Joined with industry colleagues in a range of new, innovative collaborations to help transition New Zealand towards an equitable, secure, and decarbonised energy future. These include being a founding member of the **FlexForum**; supporting Ara Ake's **EDB Challenge Fund**; and being part of the **Energy Collective Group**'s development of a prototype community education website on the actions the industry is taking to prepare for a changed energy future.
- Partnered with EEA and EECA on their **electric vehicle demand response trial**.

2.11 Asset Management Plan development process

An overview of our AMP development and review process is provided in Figure 2.11.1.

Each year we aim to improve our AMP to take advantage of customer insights, new information and new technology and solutions, such as flexibility services. These innovations help us to remain one of the most resilient, reliable, and efficient electricity networks in the country.

Our AMP development process is robust and includes challenge from peers, our leadership team and board. It is a collaborative effort that combines and leverages the talents, skills, and experience of our people. The development of our final work plans is the result of working together, testing and challenging our thinking, calibrating our direction against customer feedback, and applying an open communication and solutions-based approach. Our work programmes are tested with Orion's technical leaders, our leadership team, and our board to ensure we are building an efficient and cost-effective delivery plan that meets our customer's expectations.

Our AMP is also presented to the wider Orion team on an annual basis and is a valued reference point for communications with external stakeholders.

A key aspect of our AMP development process is top-down challenge of expenditure proposals. Significant, high value business cases are subject to review by management and the board.

Each year we aim to improve our AMP to take advantage of customer insights, new information and new technology and solutions, such as flexibility services.

For each initiative we establish a process to evaluate the outcomes, measure their success and identify opportunities for improvement or to be explored further.

We commission independent audits of our processes and procedures to ensure we identify opportunities for innovation and keep up to date with industry best practice. For the latest AMMAT report on Orion's performance in asset management practices, see Section 4.

2.11 Asset Management Plan development process continued

Figure 2.11.1 AMP development process

AMP development process

	Our board	Our leadership	Our customers
Group Strategy Ensure alignment of Group Strategy across SOI, Business Plan, Asset Management Policy and Asset Management Strategy	Board approves Group Strategy, SOI, and group business plan Reconfirm asset management strategic drivers with board	Leadership team strategy sessions Link strategy to asset management	Test asset management focus areas with customers Customer Advisory Panel consultation
Monitoring performance and adjusting Track performance, report and make operational adjustments to improve efficiency and adopt innovations	Reconfirm strategy, drivers and service level assumptions Progress update on AMP	Review actual vs forecast expenditure, review asset failure modes & report on reliability performance, calibrate/update CBRM Assess network and non-network alternatives. Assess load/growth Independent audits	Stakeholder consultation Incorporate customer feedback in economic analysis
AMR/Business cases Ensure data, systems, analysis tools, capability, engineering judgement and consideration of stakeholder interests result in appropriately documented efficient and prudent investment decisions	Key AMRs and business case as required Ensure appropriate resource and capability	Create/update AMRs and business case Network asset budget challenge (August)	Incorporate customer expectations and stakeholder interests
AMP Effectively communicate our expenditure plans, both short and long term, in a way that demonstrates our best practice stewardship of the electricity distribution system	AMP review, challenge	Signal key AMP improvements, and key expenditure step changes/ additions to board Publish AMP. AMP presentation to staff	Incorporate customer expectations and stakeholder interests

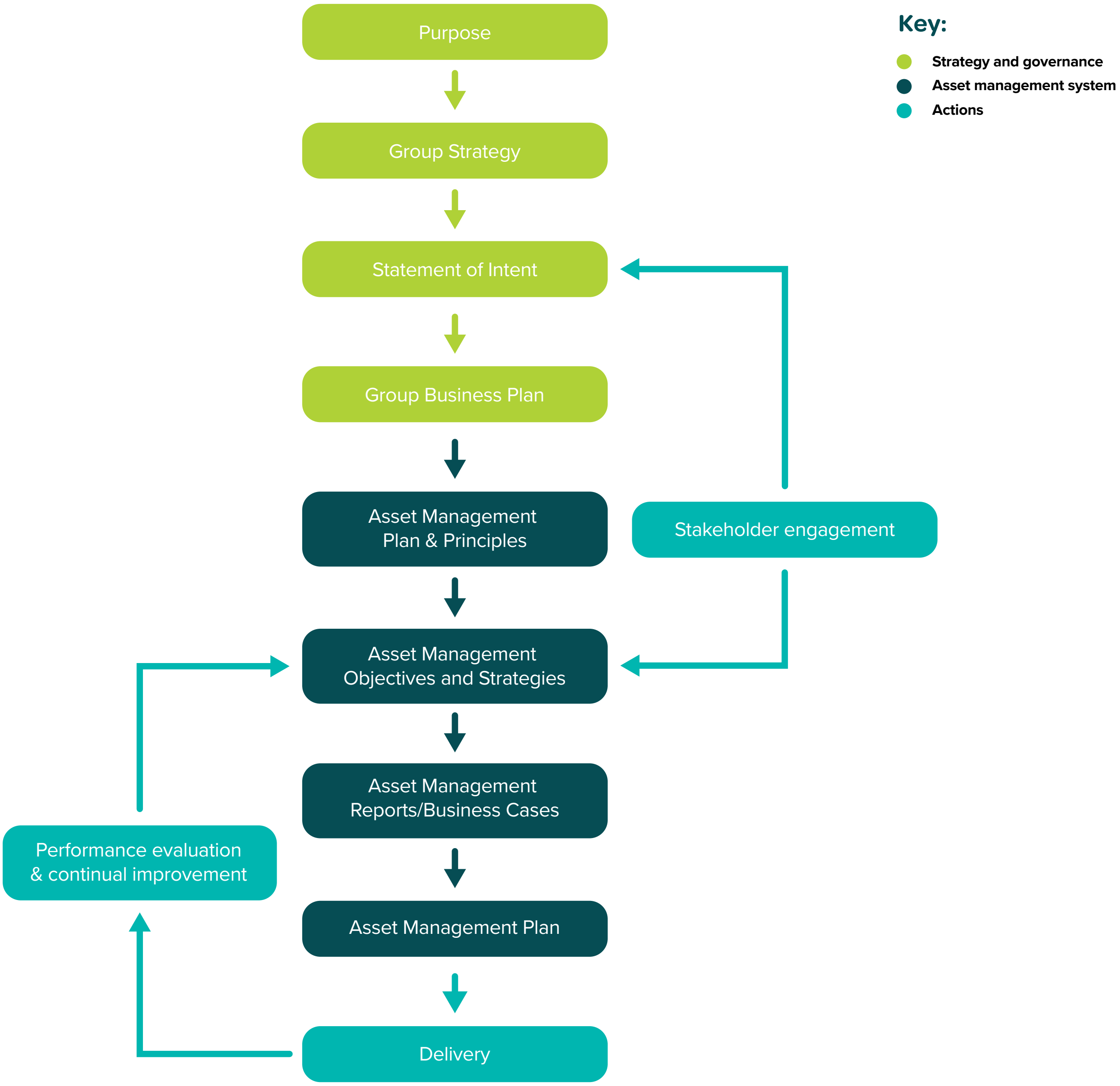
2.12 Asset management framework

Our asset management framework provides structure and process to ensure that:

- our decisions, plans, and actions are in alignment with our Purpose, our Strategy, our asset management policy and the performance targets and key initiatives of our SOI and Group Business Plan
- we deliver our services with the required level of dependability to meet our service obligations and resilience to respond to high impact events

The framework as depicted in Figure 2.12.1 is essentially a hierarchy of documents and processes that provide for clarity of purpose and alignment from our Purpose, Group Strategy, Statement of Intent, Group Business Plan and asset management policy to our investment and operational decisions and actions.

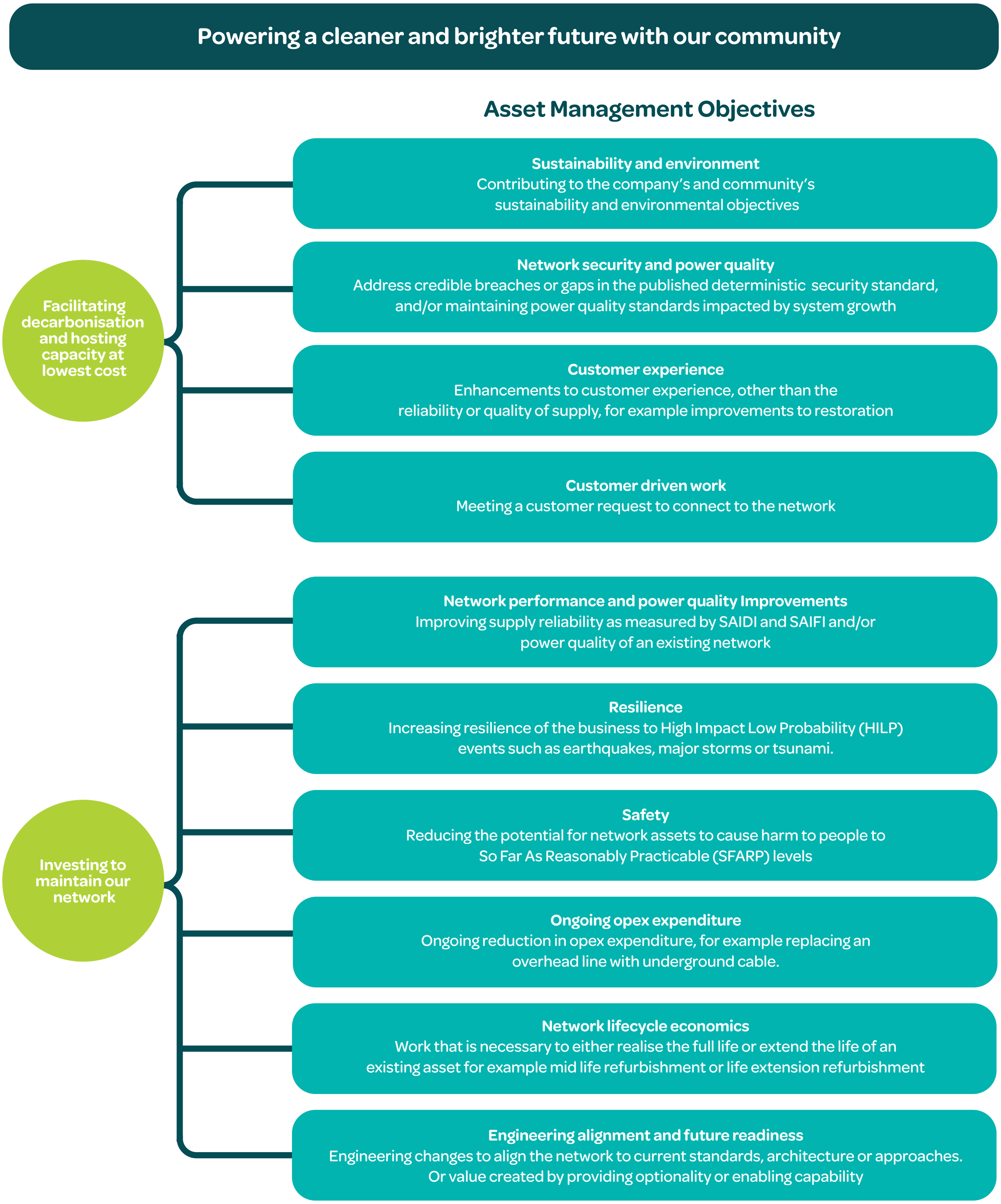
Figure 2.12.1 Orion's asset management framework



2.13 Asset management policy

Our asset management policy is to use good asset management practices to deliver on our Purpose and Group Strategy. We are committed to regular reviews of our processes and systems to ensure continuous improvement.

Figure 2.13.1 Asset Management Objectives



The principles that underpin our asset management policy are:

1. Asset management decisions prioritise safety for our people, service providers and the public
2. Risks are identified, assessed, and managed in compliance with the Orion Group risk management framework
3. Asset management decisions are aligned with the Orion Group's Purpose, Indicators, and Focus Areas of Facilitating Decarbonisation, Smart investment, Force for Good, The Preferred Workplace and Growing Civic Wealth
4. Stakeholders are consulted to ensure investments align with, future customer, community and other stakeholder needs and expectations; deliver required service levels, and meet Orion's Group strategic objectives
5. Asset management decisions are data driven to optimise the delivery of stakeholder requirements at lowest lifecycle cost
6. We maintain and enhance our asset management capability by recruiting, developing, and retaining great people
7. We continuously search for and implement opportunities to innovate and improve our asset management capability, efficiency, and effectiveness
8. All asset management activities comply with relevant laws, regulatory requirements, and company policies

2.13.1 Implementation

Our AMP sets out how we implement this policy, by describing:

- how our AMP fits with our wider governance, Group Strategy and planning practices
- how we engage with our customers to give them a voice in our decision making
- our target service levels
- our evaluation of our past performance
- our asset management practices – how we propose to maintain and replace our key network assets over time
- our network development plans – how we propose to meet changing demands on our network over time
- a picture of each asset class, its health, and maintenance and replacement plans
- the team structure and resources we have in place to deliver our plan
- our ten-year expenditure forecasts – capital and operating

2.13.2 Review

Our leadership team and technical leaders review our AMP annually and review planned projects and expenditure forecasts. Our AMP steering group provides a further review before it is presented to the board for approval.

2.14 Stakeholder interests

Our key stakeholders and their interests are summarised in Figure 2.14.1.

Throughout the development of our Group Strategy and this AMP we take into account the needs of a variety of stakeholders.

While each has their own perspective and individual needs, our stakeholder engagement programme has identified common themes that we take into consideration in our AMP planning and project assessment processes.

Our stakeholders are consistent in their view of the importance of Orion providing:

- Reliable service
- A network that is resilient
- Value for money
- A sustainable business
- Opportunities to provide their perspective
- Being pragmatic about risk management – with the safety of people paramount
- Being disaster ready; quick to respond
- Being future ready
- Being prepared for climate change risks and opportunities
- Being proactive in reducing our carbon emissions, and helping others to reduce their emissions
- Being a company they can trust

Figure 2.14.1 Stakeholders and their interests

Figure 2.14.2 lists the key ways we identify the views and interests of our stakeholders, support their interests in our asset management planning and practice, and manage conflicting interests that may arise.

Figure 2.14.2 Process for identifying stakeholder interests

Identify interest through forums

1. Customer surveys, workshops, advisory panel and major customer forums
2. Reviews of major events (storms), quality of supply studies
3. Employee engagement surveys
4. Supplier technical assessment meetings
5. Service provider in-depth interviews
6. Contract performance reviews
7. 1:1 relationship management
8. Local government and community group briefings

Support interest in asset management practices

1. Customer demand forecasts
2. Coherent network planning, security of supply standards
3. Safety plans, auditing and compliance programmes
4. Standards and procedures
5. Risk management
6. Asset management reports

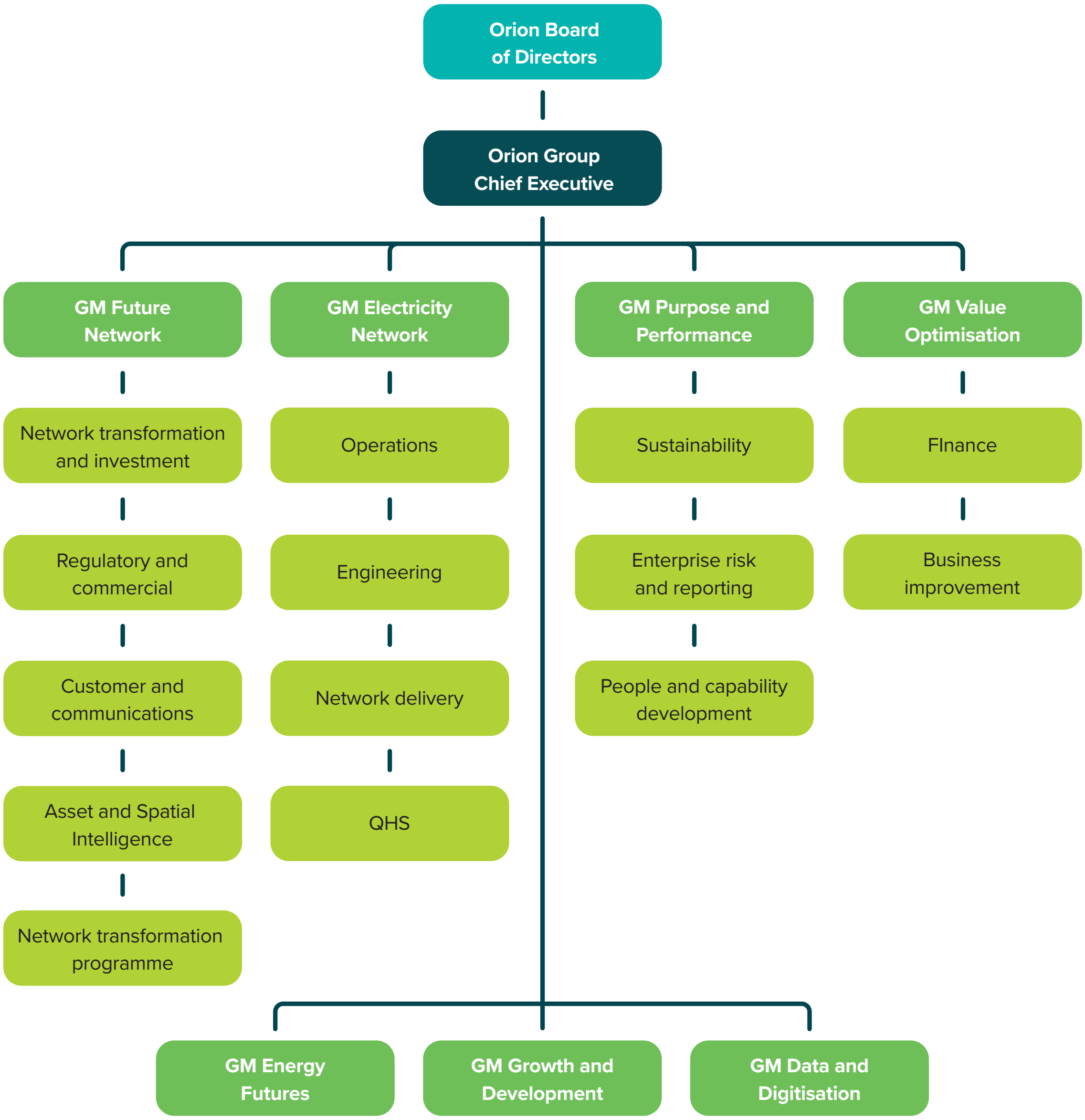
Manage conflicting interest

1. Considering the needs of stakeholders as part of our high level planning
2. Balancing the cost of non-supply and the investments to provide the security desired
3. Cost /benefit analysis
4. Our principal objective pursuant to section 36 of the Energies Company Act being "... to operate as a successful business."

2.15 Accountabilities and responsibilities

Our network is managed and operated from our administration office in Christchurch at 565 Wairakei Rd. Our governance/management structure is as follows.

Figure 2.15.1 Asset management structure



Our directors are appointed by our shareholders to govern and direct our activities. The board meets 10 times a year and receives formal updates from the leadership team of progress against strategy, objectives, legislative compliance, risk management and performance against targets.

The board is responsible for the direction and control of the company including Group Strategy, commercial performance, business plans, policies, budgets and compliance with the law. The board reviews and approves our revised 10 year AMP prior to the start of each financial year (1 April).

The board also formally reviews and approves our key company policies each year, including delegated authorities and spending authorities. Each of the General Managers in the Integrated Leadership Team (ILT) is responsible for their budget and operating within their delegated authorities.

As per our network investment framework, see Section 5.4, the technical business cases are also subjected to an internal approval process where they go through several checkpoints including substation or overhead working group followed by technical working group comprised of various General Managers before getting signed off by ILT or board depending on magnitude of expenditure.

2.16 Significant business assumptions

2.16.1 Asset management processes

2.16.1.1 Business structure and management drivers

We assume no major changes in the regulatory framework, asset base through merger, changes of ownership and/or requirements of stakeholders.

Future changes to regulation are unlikely to reduce our targeted service levels and are likely to continue the pressure to ensure cost effective delivery of network services. We believe our pricing structure and management processes encourage the economic development of our network and the chances of adverse significant changes in the regulatory framework in this regard are low.

2.16.1.2 Risk management

The assumptions regarding management of risk are largely discussed in Section 3. Although we have planned for processes and resources to ensure business continuity because of a major event or equipment failure, we have not included the actual consequences of a forecast/hypothetical major event in our AMP forecasts.

2.16.1.3 Service level targets

We have based our service level targets on customers' views about the quality of service that they prefer. Extensive consultation over many years tells us that customers want us to deliver network reliability and resilience and keep prices down. To meet this expectation, we look for the right balance between costs for customers and network investment.

See Section 4 for a summary of our recent customer engagement.

2.16.1.4 Lifecycle management of our assets

We have assumed no significant purchase/sale of network assets or forced disconnection of uneconomic supplies other than those discussed in the development of our network, see Section 6.

The planned maintenance and replacement of our assets is largely condition and risk based. This assumes prudent risk management practices associated with good industry practice to achieve the outcomes in line with our targeted service levels. Our risk assessments are based on the context of no significant changes to design standards, regulatory obligations and our other business drivers and assumptions discussed in this section.

Climate change is a real and present issue to be addressed. For the Orion network, overhead assets will be most affected by environmental changes. We are confident we can mitigate these impacts over time through our renewals programme. See Section 3 and 6.

2.16.1.5 Network development

Section 7 of this AMP outlines projects that will ensure that our network will continue to meet our customers' expectations of service.

Based on our low voltage network modelling undertaken to date, we believe most of our LV network has sufficient capacity to meet demand in the short to medium term. We understand there will be pockets of constraints that will manifest as housing intensification continues, electric vehicle uptake increases and the population in our region grows, however we are confident we can address these as they occur.

Our strategy is to apply learnings from improved visibility of our LV network and implement new technology to unlock and utilise latent capacity in our LV network. Where all capacity is utilised, other approaches such as network reinforcement or use of flexible customer owned resources, such as batteries, will be used to meet customer expectations of service.

We have assumed industry rules will ensure utility-scale solar generation connections will not be subsidised by other industry participants, including Orion, or customers. We have also assumed some biomass will be economically available and used by Central Canterbury industry as it converts from coal fired boilers.

We believe there is a place for flexibility services (DER) in the future. While the industry's maturity in this space is currently low, we are actively supporting the development of flexibility services and believe that by the end of the decade the market will be mature. See Section 5.

All forecasts in this AMP have been prepared consistent with the existing Orion business ownership and structure.

2.16.1.6 Significant sources of uncertainty

Our ability to operate in a climate of uncertainty is essential to our business' sustainability and our ability to keep pace with our customers' needs. We have identified a range of potential factors that could impact our network planning assumptions and considered a range of scenarios given the uncertainties associated with each. The primary environmental factors and uncertainties we face are discussed earlier in this section and in Section 5. We face these sources of uncertainty confident in our ability to adjust our planning if needed.

The elements of the transition to a low-carbon economy which are significant drivers for investment by Orion, are:

- transport electrification
- housing intensification and population growth
- industrial conversion to electricity
- utility-scale solar generation
- changing customer behaviour and expectations
- adapting to climate change
- loss of hot water control

Each of these elements has a variety of potential scenarios as to how they will affect demand for our network and cause constraints. Each is a source of uncertainty as to how much investment will be required to enable them.

Further, many of these elements will have impact on our low voltage network. Until we obtain smart meter data from metering providers and complete our low voltage monitoring programme, there is uncertainty over the degree of capacity remaining in our low voltage network.

In addition, there is some uncertainty over deliverability of the large increase in works forecast as being needed to ensure government decarbonisation targets are met, see Section 10. Through ongoing work with regulators, suppliers and training institutes, we are confident we can deliver our work program or any adjustment to it given changes to our assumptions on uncertainties.

Our confidence depends on our programme of work being adequately funded and supported by our network pricing. We recognise there is some uncertainty as to how regulators will enable this given the potential for large price rises to customers.

2.16.1.7 Price inflation

In this AMP our cost forecasts are stated in real dollars in FY24 terms. For some of our regulatory disclosures in Appendix F – the Report on Forecast Capital Expenditure (Schedule 11a) and the Report on Forecast Operational Expenditure (Schedule 11b) – we allow for price inflation and forecast in nominal dollars in certain components of the schedules.

Our confidence depends on our programme of work being adequately funded and supported by our network pricing.

In FY24 we forecast an increase in nominal costs for project delivery of 12% – approximately 5% above the inflation rate forecast for that year. Beyond that we assume nominal costs stay in line with general inflation. We will revisit and review this assumption in our next AMP, as we believe there is a risk that nominal cost increases will continue to trend above general inflation forecasts.

2.16.1.8 Potential differences between our forecast and actual outcomes

Factors that may lead to material differences include:

- regulatory requirements may change
- customer demand may change and/or the requirement for network resilience/reliability could change. This could be driven by national policy, economic and/or technology changes. This could lead to different levels of network investment
- changes in demand and/or connection growth could lead us to change the amount of and timing of our network projects
- one or more un-forecast large energy customers/ generators may connect to our network requiring specific network development projects
- major equipment failure, a major natural disaster or cyber-attack may impact on our network requiring significant response and recovery work. This may delay some planned projects during the period until the network is fully restored
- input costs and exchange rates and the cost of borrowing may vary influencing the economics associated with some projects. If higher costs are anticipated, some projects may be abandoned, delayed or substituted
- changes to industry standards, inspection equipment technologies and understanding of equipment failure mechanisms may lead to changing asset service specifications
- other factors discussed elsewhere in this AMP

3 Managing risk

Photo: Connetics crew laying a new 66kV cable to increase the capacity and resilience of the power network to support growth in Belfast and northern Christchurch.

Contents

3.1 Introduction

Prudent risk management strengthens our ability to provide an electricity delivery service that is safe, reliable, resilient and sustainable.

Orion Group uses an Enterprise Risk Management (ERM) approach. This ensures we have a complete, integrated, group-wide focus on managing our strategic and operational risks and enables Orion to make clear decisions around opportunities.

Our ERM programme:

- supports the Orion Group's Purpose, strategy and objectives
- supports our community's aspirations for a liveable region that has strong connected communities, a healthy environment and a prosperous economy
- identifies and manages significant and emerging risks
- enables us to make clear decisions around the opportunities that are inherent in some risks
- stimulates continuous improvement

Our approach to ERM is grounded in our belief that:

- every person has a responsibility to identify and manage risks
- a healthy and collaborative culture is a vital part of our risk management
- risk management relies on good judgement, supported by sound evidence
- risk management is all about creating and protecting value for our customers, our community, our people and our key stakeholders
- we can always improve

3.2 Our risk context

Electricity is a fundamental necessity in the modern world, particularly as our community transitions to a low carbon economy in an effort to combat climate change. We expect community reliance on our service to increase in the long term. At the same time, the energy sector is moving through a period of unprecedented change, while contending with the global challenges of the climate emergency, pressure on resources, cost inflation and geopolitical conflict. These factors lead to a complex and dynamic risk context for Orion.

Our community is increasingly dependent on our electricity distribution service, so it's essential we identify and manage our key risks. Our community especially depends on electricity during and after High Impact Low Probability (HILP) events such as major earthquakes or storms. Section 60 of the Civil Defence Emergency Management (CDEM) Act states that as a key lifelines utility, we '*... must be able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency.*'.

As further context, our service region:

- is a significant earthquake zone. For example, recent research from Te Herenga Waka–Victoria University of Wellington estimates that there is a 75% chance of a major Alpine Fault earthquake in the next 50 years
- has cold winters and is subject to weather extremes – including snow and/or wind storms
- has no reticulated natural gas
- has urban 'clean air' restrictions on the use of solid fuel heating

We also know that:

- we are in the midst of a climate change emergency, and there is increasing urgency to address this issue and report on our adaptation plans
- our customers will increasingly convert from carbon-based fuels to renewable energy sources
- our customers will increasingly inject energy back into our electricity distribution network
- the availability of people with the skills to deliver and support this increased activity in the electricity sector is constrained
- global risk sources such as pandemics, cyber-crime and geopolitical conflict are increasing in their likelihood and potential consequences
- the pace of technology change will continue to increase
- other lifelines utilities in our region depend on electricity, and this interdependency is important
- electricity distribution networks have specific hazards and risk sources by their very nature
- Electricity Distribution Businesses and the wider electricity sector are highly-regulated
- the Energy Companies Act requires that our principal objective shall be to operate as a successful business
- we are publicly accountable to our customers, our community, our shareholders and industry regulators
- our shareholders are also publicly accountable to our community

Our community is increasingly dependent on our electricity distribution service, so it's essential we identify and manage our key risks.

3.3 What our community wants from us

We know our customers and community want us to provide a safe, reliable, resilient and sustainable electricity delivery service – see Sections 4.2 and 4.3.

Our customers and community may suffer extreme adverse impacts financially or on other dimensions of their wellbeing from prolonged or frequent interruptions to their power supply, especially if they happen in winter.

Past experience has shown that HILP events such as earthquakes and wind storms can cause extensive damage to our assets and prolonged power outages.

For these reasons, we will:

- use the most reliable and comprehensive information to identify, assess and treat our key risks
- apply our experience, knowledge and good judgement to take reasonably practicable and timely steps to treat our key risks, including those driven by climate change

We especially focus on our critical network assets and systems, for example our network control systems and our 33kV and 66kV sub-transmission assets, as these high voltage assets supply the greatest numbers of our customers and they can be the most complex to repair or replace if they are damaged.

3.4 Our approach to risk management

3.4.1 Our Enterprise Risk Management process

Our ERM process is consistent with the international risk management standard ISO 31000:2018.

3.4.2 Our risk management appetite

In matters of health and safety and key operational risks, our risk management appetite remains low. When we assess our other risks we consider the potential upside, and how we might manage our response to leverage the possibilities it presents.

3.4.3 Our climate change emergency risk management

Climate change presents risks and opportunities to Orion strategically, in addition to those it presents in our physical environment and operationally. To effectively deliver on our Purpose – Powering a cleaner and brighter future with our community – we must consider the risk and opportunity inherent in changing strategies, government policy or investments as our community works to reduce its carbon emissions.

We group the opportunities and risks related to climate change into three categories:

- **upside growth opportunities** – as a result of increasing demand for electricity from renewable sources to replace fossil fuels such a coal, gas and transport fuels. Increased opportunities for automation also create the potential for a more resilient energy system through distributed energy resources. This means we have an opportunity to build and support an efficient, inclusive and resilient energy system. One that is robust to handle what the future may bring
- **physical risks** – these can be event-driven, such as more frequent and severe storms, or longer-term chronic shifts such as gradual rising temperatures and sea levels
- **transition risks** – these can be wider changes that stem from social, legal or policy shifts away from the use of fossil fuels and typically are classed as strategic impacts

Overall, we continue to believe that our upside growth opportunities from climate change will outweigh our physical and transition risks over the next ten years.

We believe Orion has an important role to help our community decarbonise – for example by encouraging the uptake of EVs and the conversion of process heat to electricity. This continued growth and reliance on electricity reinforces our asset management strategy to continue to invest to have a safe, reliable, resilient and sustainable electricity distribution network.

Our largest potential operational impacts relate to vegetation colliding with our lines and more frequent severe weather events, particularly high winds in inland areas that will affect our largely overhead rural network.

Our network is already engineered and managed to be resilient to storms and we have active vegetation management programmes in place, with a plan to increase our spending on vegetation control over the next 10 years. Our team continues to improve our understanding of climate effects on our network to adapt and mitigate risks where appropriate, or reasonably practicable.

Overall, we continue to believe that our upside growth opportunities from climate change will outweigh our physical and transition risks over the next ten years.

Our largest potential impacts in the transition to a low carbon economy relate to the speed of the community's movement away from fossil fuels which can also impact our ability to find people with the skills to design and build the infrastructure we need. Regulatory agility and the ability for existing systems to integrate new technology may also impact our ability to adapt to changing circumstances in a timely manner. Despite the unknown nature of these changes and the technology that accompanies them, we remain confident Orion's electricity distribution service will continue to grow and adapt to serve the needs of our community.

3.4.4 Our network risk management

We are proactive and prudent managers of Central Canterbury's electricity distribution network. We continuously improve how we:

- forecast customer demand for our services – including the potential impacts of new technologies, climate regulation and our changing environment
- plan and build for network safety, capacity, reliability and resilience
- monitor, maintain and enhance the condition of our key assets and systems via our ongoing lifecycle management
- operate, monitor and control access to our network
- maintain an appropriate level of redundancy and emergency spares
- maintain and develop competent employees and service providers
- maintain an effective vegetation management programme
- otherwise identify, assess and manage our key risks

3.4.5 Our people risk management

We achieve effective risk management via our people, and our aim is to have:

- a healthy and safe workplace
- a resilient workforce
- a collaborative, diverse and inclusive culture
- effective employee recruitment and retention processes
- effective capability development and training
- effective long-term succession planning

We also support wider industry competency initiatives to address the growing need for people with the rights skills to serve the increase in demand for electricity – for example:

- the Energy Academy
- the Ara Trades Innovation Centre, which has an electricity distribution trades training centre
- the University of Canterbury's Power Engineering Excellence Trust

Our aspiration is to be an employer of choice. Our focus on the wellbeing of our people, flexible working practices and a learning environment support us on this journey.

3.4.6 Our commercial and financial risk management

Our revenue supports ongoing investment to meet the long-term interests of our shareholders, customers and communities. We manage our commercial and financial risks through:

- providing great service
- appropriate delivery service agreements and constructive engagement with electricity retailers and major customers
- active engagement with regulatory agencies
- prudent financial policies and procedures
- robust internal controls including a business assurance programme

3.4.7 Our regulatory risk management

The electricity industry is highly regulated, via multiple regulatory agencies. We aim to comply with our obligations and to constructively engage with agencies on key regulatory developments.

3.4.8 Our insurance

To transfer some of our financial risk, we have the following insurances in place – consistent with good industry practice:

- our material damage insurance policy insures us against physical loss or damage to specified buildings, plant, equipment, zone and distribution substation buildings and contents – and is based on assessed replacement values
- our business interruption insurance policy indemnifies us for increased costs and reduced revenues as a consequence of damage to insured assets – with an indemnity period of 18 months
- we have a number of liability policies — including directors and officers, professional indemnity, public liability, statutory liability and contract works

Our key uninsured risks, which are effectively uninsurable for all Electricity Distribution Businesses (EDBs), are:

- lost revenues – although the Commerce Commission now allows EDBs to recover uninsurable lower revenues from customers in later years. This ability to recover is capped at 20% of annual delivery revenues
- damage to overhead lines and underground cables

We also require our key network service providers and suppliers to have appropriate insurance for:

- third party liabilities
- plant and equipment
- motor vehicle third party
- product liability

3.5 Our risk management responsibilities

3.5.1 Our everyday risk management

Orion's board of directors oversees the key strategic and operational risks that have the greatest potential to adversely affect the achievement of our objectives. Management reports to the board on key risks, emerging risks and environmental context.

We also seek independent expert advice when appropriate.

Our everyday risk management is mostly handled by line management as part of their normal duties. We also have three teams that support line management to undertake risk management:

- **Enterprise Risk Lead** – coordinates our management and governance processes, our ERM framework and our insurance programme
- **Quality, Health, Safety** – six FTEs help our line management to continuously improve our processes in these areas
- **Risk steering committee** – a cross-functional and diverse team of people leaders and employees who provide support, guidance and oversight to the organisation's identification and management of current and emerging risks.

The board audit risk committee also oversees an active assurance programme, that is facilitated by an independent chartered accounting firm.

The Civil Defence Emergency Management Act 2002 (CDEM) requires us to:

- function during and after an emergency, and have plans to support this
- participate in CDEM planning at national and regional level if requested
- provide technical advice on CDEM issues where required
- align our business continuity responsibilities using Civil Defence's 4Rs approach to resilience planning – reduce, ready, respond and recover

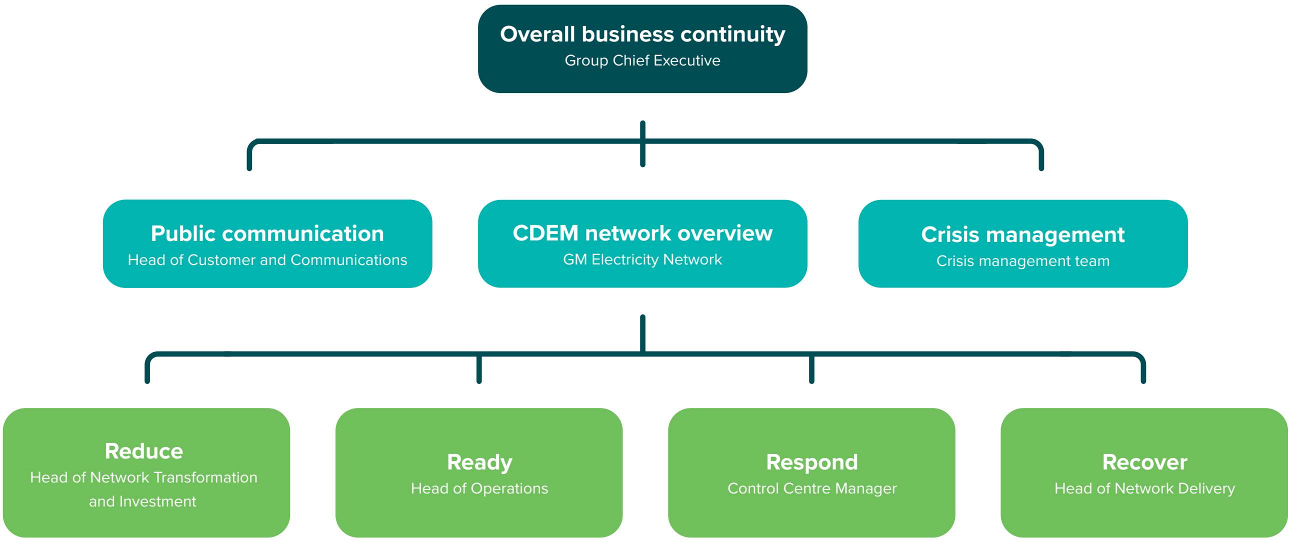
3.5.2 Our HILP / crisis risk management

High Impact Low Probability (HILP) events such as natural disasters, pandemics or cyber-attacks necessitate situation specific reporting and responsibility structures. Each HILP event is different, so we expect to plan-to-plan following such events.

Orion's board of directors oversees the key strategic and operational risks that have the greatest potential to affect the achievement of our objectives.

3.5 Our risk management responsibilities

Figure 3.5.1 Our HILP and crisis risk management responsibilities



- **Reduce** – means we implement measures in advance so that the impacts of future HILP events will be less. For example, we have invested in increased IT controls against malicious cyber-attack.
- **Ready** – means we have the people, resources and procedures in place or available to respond to a future event. A good example of this is that we smooth our planned network opex and capex over time so our service providers can develop and maintain stable locally sourced capability that may be redeployed to respond when HILP events occur.

  We also have formal and informal mutual aid agreements with EDBs around the Aotearoa New Zealand to provide additional support in HILP events if needed. To respond to large scale events, we have appropriate stock levels of repair items such as replacement poles in strategically placed depots around our region.

  Our readiness delivers on our focus to continually improve our network and business resilience. Addressing this foreseeable risk means that in the event of a major event, we can respond efficiently using our systems, resources and recovery processes, and power will be restored as quickly as possible.
- **Respond** – means we deal with the immediate and short-term impacts of HILP events. We first seek to understand what has occurred and the main impacts, and we then plan, prioritise and implement measures to ensure a response that has the greatest benefit for the greatest numbers of customers in the shortest practicable time – this approach is what we refer to as plan-to-plan.
- **Recover** – means we deal with the medium to long term impacts of HILP events. We prioritise and plan our major works to restore our network condition and capability over an appropriate period. Our recover phase can also involve prudent upgrades to parts of our network, given our new risk learnings and new context from the HILP event.

  A good example of this is the relocation of our base for our Primary Service Delivery Partner and key emergency service provider, Connetics, to Islington, a more central location in our region with fewer natural risks.

Our readiness delivers on our focus to continually improve our network and business resilience.

3.6 Our risk assessments and risk evaluations

3.6.1 Our risk assessments

We assess the potential consequences and the likelihood of those potential consequences for our different types of risk areas, such as:

- HILP events
- health and safety
- pandemics
- business continuity and resilience
- people and competence
- supply chain and procurement
- project management
- environment
- climate change
- sustainability
- financial
- strategic
- network capacity and reliability
- IT systems – including cyber security
- legislation and regulation
- reputation

We assess our risks in a consistent way and have high-level guidelines to inform our judgements. These are guidelines rather than rules, because unique contexts can affect any situation.

When appropriate, we engage independent experts to help us assess and evaluate our risks and risk controls.

Our risk guidelines have heatmap scores for our risk assessments. These rank risks from 1 to 25 as shown in Table 3.6.1.

Table 3.6.1 Our risk assessment guidelines

Likelihood		Consequence				
		Minor	Moderate	Serious	Major	Severe
Almost certain	95% to 100%	6	13	18	23	25
Likely	65% to 94%	5	9	15	21	24
Possible	35% to 64%	3	8	14	19	22
Unlikely	6% to 34%	2	7	11	16	20
Rare	0% to 5%	1	4	10	12	17

Risk ratings
Extreme
Very high
High
Medium
Low

Our **likelihood rating** guidelines also inform our judgement. Likelihood takes into consideration the external and industry context as well as the history of occurrence. When considering likelihood, we consider relevant issues such as:

- how often a task is carried out, or how often a situation might occur
- how and when the consequence might occur and to whom
- relevant evidence and history
- new factors that might make history less relevant

Our **consequence rating** guidelines inform our judgements. We recognise there could be several different credible consequences that need to be considered for any event or risk source – for example, safety, financial and reputation. We consider credible consequences that could occur and their potential severity:

- our consequence ratings aim to reflect credible scenarios, given our context and risk treatments
- our likelihood ratings reflect those credible scenarios, including residual risk that remains after implementation of our risk treatments and controls

We assess our risks in a consistent way and have high-level guidelines to inform our judgements.

3.6.2 Our risk evaluations

When we evaluate our risks, we decide what to do about them, if anything. We summarise our five major options for action or otherwise, and our framework for deciding which option to take, as shown in Figure 3.6.1.

As an extra step, we consider our wider context, using good experience, knowledge and judgement. We ask:

Given our wider context, can we live with our risk assessment rating for this risk, or do we need to change it by way of risk treatment or transfer?

Figure 3.6.1 Our five main risk evaluation options

As a general principle, the higher the risk the more decisively we act. Our overall action and escalation guideline is shown in Table 3.6.2.

Table 3.6.2 Our risk treatment and escalation guidelines

Risk ratings	How to respond	When to escalate	Who to
Extreme	Take immediate and decisive action to treat risk	Immediate, and as appropriate	Integrated Leadership Team/board
Very high	Take timely action to treat risk	Monthly, and as appropriate	Integrated Leadership Team/board
High	Treat risk if reasonably practicable	Quarterly, and as appropriate	People leader/Integrated Leadership Team
Medium	Consider treating risk if reasonably practicable	Annual, and as appropriate	People leader
Low	Accept risk, manage as per normal procedures	Annual, and as appropriate	People leader

3.7 Our key operational risks

Our key operational risks are:

Table 3.7.1 Our key risks

Key risks	Examples
Health and safety	Fatality or permanent disability to a worker, service provider or other person
Natural disaster	HILP events – for example, major earthquake, tsunami triggered by a major earthquake or severe storm
Weather event	Weather event that results in significant business disruption – becoming more frequent due to climate change
Serious cyber security breach	Security breach that especially affects our network control systems
Pandemic	Pandemic that causes business continuity issues; impacts on costs, the supply chain, people capacity
Significant network asset failure	Extensive network asset damage and/or extended outages to many customers
Workforce availability and skills	Inability to attract, develop and retain people with the skills and capabilities that support Orion in meeting current and future needs

Our overall assessments for these key risk categories are shown in Table 3.7.2.

The ratings in Table 3.7.2 are as at 5 March 2023, and are regularly reviewed.

Table 3.7.2 Our overall operational key risk assessments

Likelihood		Consequence				
		Minor	Moderate	Serious	Major	Severe
Almost certain	95% to 100%			4		
Likely	65% to 94%			8		
Possible	35% to 64%		7	5, 6		3
Unlikely	6% to 34%					
Rare	0% to 5%				2	1

1. Serious health and safety incident that causes a fatality
2. Serious health and safety incident that causes injury
3. Major earthquake – could also trigger tsunami
4. Weather event
5. Pandemic
6. Cyber security breach
7. Significant network asset failure
8. Workforce availability and skills

In the following pages we detail our key risks along with the main mitigation and controls we use to manage them.

3.7.1 Health and safety

Ensuring our people can work safely and our community can go about its daily life in a safe, healthy and sustainable environment is not simply a matter of compliance - it is embedded in our culture.

We continue to strengthen our quality, health and safety focus. We're vigilant in identifying and assessing risks, and continually improving our processes and outcomes.

We aim to actively identify, assess and manage the critical risks typically associated with operating an electricity distribution network by:

- maintaining well-developed and documented policies and procedures
- engaging with trained and competent field workers who can work in complex and dynamic environments
- working with our service providers to encourage safer practices when working around Orion infrastructure
- utilising remotely operated devices to monitor and operate aspects of our network
- taking a collaborative, learnings-based focus for all safety incident and investigations

- continuously improving our risk management and reporting
- conducting public safety education campaigns
- applying quality assurance oversight to provide a better overview of interrelated factors

We have dedicated teams of people to help us maintain a focus on the health, safety and wellbeing of our people, our service providers, and our community.

Our Health and Safety and our Public and Asset Safety Committees have employee representatives from across Orion who meet regularly to review incidents, identify opportunities for improvement in work practices and the work environment, and assist in the education of our people.

We recruit, train, and equip our team members appropriately for their roles. We understand our people are faced with challenging decisions each day – therefore we support them with a wellbeing programme aimed at ensuring our team members are fit to be at work and safely carry out their duties.

We actively consider potential health and safety risks when we design and construct new network components, through our documented 'safety in design' process.

We collaborate with our neighbouring and national networks, and industry associations such as the EEA and the ENA, to share knowledge and help us understand our industry risks and what is considered 'good practice' management of those risks.

Much of the field work on our network is carried out by approved network service providers. We require our network service providers to have an equivalent health and safety management system to our own. We ensure our network service providers conform to our requirements through our formal contract management process and our auditing programme.

As with all electricity distributors, the Electricity (Safety) Regulations 2010 require us to have an audited public safety management system, with the aim to promote public health and safety, and the prevention of damage to property around the supply and use of electricity. To demonstrate we conform with this requirement, we are independently audited at regular intervals against NZS7901 Electricity and Gas Industries – Safety Management Systems for Public Safety, and have been assessed as meeting the requirements.

To protect our community from potential harm associated with our infrastructure, we have documented policies and procedures, and create physical barriers which restrict access to our electrical network infrastructure. We:

- prevent access to restricted areas by the public and unauthorised personnel
- prevent inadvertent access to areas by authorised personnel
- prevent entry by opportunist intruders without specialised tools
- slow or impede determined intruders
- ensure ground mounted infrastructure in public areas such as kiosks and distribution boxes are designed to be safe to touch.

Electricity is hazardous and regardless of our extensive programme of prudent, proactive measures our risk rating for health and safety is high. At all times, there is credible potential for a member of our team, a service provider or person in our community to suffer a serious injury or a tragic fatality.

This compels us to have effective quality, health and safety performance and continual vigilance by every team member.

3.7.2 Natural disaster

3.7.2.1 Major earthquake

The Canterbury and Kaikoura earthquakes of 2010, 2011 and 2016 indicate that our region's greatest natural disaster risk is a major earthquake. A future major earthquake could be caused by the Alpine Fault or by other known or unknown faults.

A Te Herenga Waka–Victoria University of Wellington study indicates a 75% chance of a major Alpine Fault earthquake in the next 50 years. The research also indicates an 82% chance of the earthquake being magnitude 8 or higher. We have assessed the risk of an Alpine Fault earthquake as severe and moved the likelihood to possible. We have reviewed our crisis management processes and business continuity plans to ensure that we are prepared for this increased likelihood.

Our region's greatest natural disaster risk is a major earthquake.

An Alpine Fault earthquake would be centred further away from our urban network and would not be as sharp as the 22 February 2011 earthquake, but it would have a far longer duration, perhaps some minutes. This would test the resilience of our network in different ways to 2011. Our network extends into the Arthurs Pass region, close to the fault line, and while designed and built to the same rigid standards of our flat geographical areas, the earthquake effects are likely to be greater and for longer in this area. A major Alpine Fault earthquake may result in a major outage to significant parts of our network – and the impacts of that on our community would be more severe if it occurs in winter.

Fortunately, we were well-prepared for the Canterbury earthquakes in 2010 and 2011. We also completed our earthquake recovery projects in FY18, and as part of those initiatives we further enhanced our earthquake resilience.

Our current major planned resilience initiative is to replace the remaining 40km of oil filled 66kV cables over ten years or so. These cables represent old technology and the skills to maintain and repair them if they become damaged are increasingly rare internationally and locally.

These were the type of sub-transmission cables that failed in the eastern suburbs in the 2011 earthquake and we had to abandon and replace them completely.

These cables may be susceptible to a series of prolonged tremors from a major Alpine Fault earthquake – including significant aftershocks. Christchurch has significantly developed to the west since 2011, so there is an increasing dependence on a resilient electricity supply in that area of our region.

A major future earthquake will also have significant impacts on the ability of some of our team members to contribute to our response and recovery initiatives. We treat this risk in practicable ways – including via:

- well documented policies and procedures
- competent employees and service providers who can and do perform cross-over duties
- policies and practices that aim to support employee well-being
- flexible IT and communication systems that enable our people to work remotely for extended periods of time
- a policy and practice to plan-to-plan and adapt following a major event as necessary
- crisis management processes including simulation events

In summary, we have implemented and continue to implement practical steps to address our earthquake risk exposures.

3.7.2.2 Tsunami

Another major natural disaster risk is tsunami, most likely from a major earthquake offshore. This could result in outages in areas of our network near the east coast. Since 2011, we have significantly reduced the potential impacts of a major tsunami as our key service providers have moved their depots significantly further inland. Our network assets near the east coast will inevitably be exposed to tsunami, particularly as climate-related sea level rise increases.

3.7.3 Weather event

Severe storms can and do result in outages to significant numbers of our customers of up to one hour in urban areas and up to three days in rural areas. Longer outages can especially affect customers in remote rural areas where access may be difficult and snow depth may be more severe.

We have continuously improved our network practices in light of past storms in our region – including significant wind storms in 2013 and 2021 – particularly for rural areas in our

Our current major planned resilience initiative is to replace the remaining 40km of oil filled 66kV cables over ten years or so.

service region. We have implemented these improvements over time as part of our ongoing network asset lifecycle process and we have implemented strengthened asset loading standards for new network components. Examples of such changes for our rural service area include revised pole spans, revised pole and crossarm types – as appropriate for credible wind and/or snow loadings. Our credible snow loading forecasts recognise that local snow is relatively wet and heavy, in contrast to snow that falls in the middle of large continents.

Climate change will exacerbate challenges to our overhead network and for more information on how we plan to improve our future resilience in this area, see Section 2.

Our urban network is largely underground – so our weather risks mainly relate to our widely dispersed rural overhead lines.

An important element for this risk category is that the vast majority of the damage to our network in severe storms is due to tree branches, and even whole trees, coming into contact with our overhead lines – especially in rural areas.

Our urban network is largely underground – so our weather risks mainly relate to our widely dispersed rural overhead lines.

3.7 Our key operational risks continued

There is currently no scope for us to require private tree owners to remove hazards if the trees and branches are outside a regulatory cut zone. In order to reduce this risk, we have an active vegetation management programme that aims to:

- ensure tree owners comply with the tree regulations
- enlist the long-term support of tree owners to reduce threats to our rural overhead network

Important risk assessment context includes:

- we have gradually improved the resilience of our rural overhead network over the last 25 years via our asset lifecycle programme
- we have also invested to improve our network switching capability in rural areas – in order to better isolate affected areas so that we can reduce the number of customers affected by network damage in many circumstances
- overhead networks are generally more susceptible to outages caused by trees, but they are faster and less expensive to repair than underground cables
- we are also working with industry and government to introduce changes to address tree risk more efficiently

We believe that flooding is a medium to low risk for our network. In 2021 and 2022 we worked with the University of Canterbury to map the effect of sea level rise on the impact of tsunami, groundwater risk and localized flooding along our network.

We expect that localised floods will occur from time to time near the Avon and Heathcote rivers. We have documented procedures to electrically isolate our network in areas affected to protect our network components before they are significantly damaged. Our administration office, including our control room, is not at significant risk from flood.

3.7.4 Cyber security breach

All businesses are now potentially susceptible to cyber-attacks from any part of the globe.

The security of our systems is vital to our ability to deliver a safe, reliable, resilient and sustainable service. We have two key categories of information systems risk:

- catastrophic failure of our systems, for any reason
- malicious third party attack on our systems

We reduce the likelihood and potential impact of catastrophic failure of our information systems through a combination of procedures and technologies, including:

- robust systems procurement and maintenance – hardware and software
- rigorous change management
- good practice for regular and ongoing data and system back-ups and archiving
- highly resilient facilities
- robust security – computer network and physical
- key hardware and systems mirroring between physically separate sites
- active cyber security penetration testing. Customers benefit from safe online services, rigorous protection of their personal information and the integrity of our asset information and asset management systems

To prevent and reduce the potential impacts of attacks by malicious third parties, we employ layers of cyber security at server, network and device levels and subject them to penetration testing – a simulated cyber attack. We aim to employ fit-for-purpose and up-to-date security systems that track and respond to suspicious patterns of behaviour, known digital signatures and explicit security breaches.

We regularly update and train our people on cyber security and we seek their vigilant and active support for a secure information systems environment.

We use the knowledge and experience of others by consulting with our peers in the industry, Government agencies and independent experts. The latter group helps us to build our capacity and also audit our systems and practices so that we continuously improve our resilience to cyber threats.

3.7.5 Pandemic and variants

COVID-19 brought the risk of a pandemic into sharp focus. As an essential service provider Orion is acutely conscious of our responsibility to maintain vital power services to our community throughout pandemics. As the situation evolved, our appreciation of the risks of pandemics on our ability to maintain our service to the community grew.

Skilled people are critical to Orion's ability to operate, manage and maintain the electricity network safely. There is therefore a need to limit any spread of illness through our workforce. During the COVID-19 pandemic we took significant steps to ensure the safety and wellbeing of our employees, particularly those who worked in critical control centre and customer support roles, as well as our operators in the field.

COVID-19 continues to impact our costs and supply chain, in particular on manufacturing and time frames for shipping, although to a lesser degree than previously. We anticipate these delays will continue, albeit due to other geopolitical and climate factors. To manage this risk, we have increased supplier orders and carry extra supplies of essential items, as well as ordering equipment with extended lead time to ensure it is with us when needed.

Throughout all COVID-19 Alert levels, Orion continued to operate a safe and reliable network, and provide reassurance to the community that there was no heightened risk to the supply of power. We adapted to the evolving situation and believe our experience provided us with valuable learnings for any future widespread disruptions.

3.7.6 Major network asset failures

3.7.6.1 Lifelines interdependencies

All lifelines utilities depend on electricity – so we plan and act for resilience accordingly. We also plan for when other lifelines services may not be available to us – for example, mobile and landline phone networks.

The New Zealand Lifelines Council has assessed and rated lifeline utilities interdependencies during/after HILP events, using a three-tier rating system:

- 3 – essential for the service to function
- 2 – important, but the service can partly function and/or has full back-up
- 1 – minimal requirement for the service to function

As shown in Table 3.7.3, the Council rates electricity as 'essential' or 'important' for virtually all other lifelines utilities during/after HILP events. With a 'total dependency' score of 31, electricity has the fourth equal highest overall score.

Over the last few years, we have improved the resilience and reliability of our service to other key lifelines utilities, including to Lyttelton Port and Christchurch International Airport.

We also maintain a fleet of standby generators that can be repositioned at relatively short notice to key lifelines utilities in time of need – see a description of these in Section 6.19.

We are an active member of our region's Civil Defence lifelines group, and that engagement continues to inform our priorities to effectively address the interdependencies that relate to our service.

3.7.6.2 Grid Exit Points (GXPs)

Asset failure at either of our two key GXPs at Bromley or Islington, or our own network equipment at those sites, could be caused by liquefaction. At Bromley, ground settlement of 20mm to 40mm is possible, but this is unlikely at Islington. We rate this risk as low to medium.

In FY22 we commenced building a new GXP in Norwood which will increase Orion's capacity to drawdown power from the national grid by 200MW, or 25 per cent, and increase resilience in our network, particularly in the Selwyn District. The new GXP is expected to be commissioned by December 2023.

We have recently implemented several improvements to the spur assets we have purchased from Transpower at Bromley and we will continue to implement improvements over the next few years. Transpower has also implemented improvements at our GXPs, pursuant to new investment agreements with us. In FY19, we purchased 33kV spur assets at the Islington GXP and we have upgraded our equipment and converted the arrangement there to an indoor switch room.

Our 66kV sub-transmission 'Northern Loop', commissioned in June 2016, has created a more interconnected sub-transmission system which significantly reduces our risks to GXPs. This AMP also details planned capex projects to further improve the interconnected nature of our sub-transmission system.

Table 3.7.3 NZ Lifelines Council interdependency ratings during/after HILP events – 2020

The degree to which the utilities listed to the right are dependent on the utilities listed below	Roads	Rail	Sea Transport	Air Transport	Water Supply	Wastewater	Stormwater	Electricity	Gas	Fuel Supply	Broadcasting	VHF Radio	Telecomms	**Total Dependency**
Fuel	3	3	3	3	3	3	3	3	3		3	3	3	**36**
Roads		3	3	3	3	3	3	3	3	3	2	2	3	**34**
Telecomms	3	2	2	2	3	3	3	3	3	2	2	3		**31**
Electricity	2	2	3	3	3	3	2		2	2	3	3	3	**31**
VHF Radio	2	2	3	3	2	2	2	2	2	2	2		2	**26**
Broadcasting	2	2	2	2	2	2	2	2	2	2		2	2	**24**
Air Transport	2	1	1		2	2	2	2	2	2	2	2	2	**22**
Water Supply	1	1	1	2		3	1	1	1	1	1	1	2	**16**
Stormwater	2	1	1	2	1	1		1	1	1	1	1	1	**14**
Wastewater	1	1	1	2	1		1	1	1	1	1	1	1	**13**
Rail	1		1	1	1	1	1	1	1	1	1	1	1	**12**
Sea Transport	1	1		1	1	1	1	2	1	1	1	1	1	**13**
Gas	1	1	1	1	1	1	1	1		1	1	1	1	**12**

3.7.6.3 Zone substations

Zone substation failures across our network could be caused by liquefaction or asset failure. This could result in local outages of up to one day for several thousand customers. For most of our 50 zone substations, we rate this event as a low to medium risk.

Since 1995, we have assessed and seismically strengthened our zone substations as appropriate, following detailed engineering studies. In the 2011 earthquake, we had two severely damaged urban zone substations and we subsequently:

- replaced Brighton zone sub on better ground 1.5km away at Rawhiti
- rebuilt Lancaster zone sub on the same site to be more resilient

We also have:

- targeted high voltage interconnectivity and diversity of supply
- contingency switching plans
- oil containment bunds at all sites with power transformers and generators
- additional simple and low-cost hold-down ties for indoor voltage transformers that are not otherwise secured
- service providers who can cease planned work at short notice to respond to network incidents

3.7.6.4 Subtransmission overhead lines – 66kV and 33kV

Our overhead lines are widely dispersed and they are relatively easily repaired in an earthquake event. In the 2011 Canterbury earthquake, although there was damage to certain components for example, insulators, there was relatively little damage to our overhead lines when compared to an extreme weather event.

Our ability to operate and deliver our Purpose and meet our customer's future needs relies on the availability of competent, experienced, and skilled people.

Our overhead lines in rural areas are exposed to extreme weather events and there may be outages in some remote areas of our network. Subject to the ability of our repair teams being able to access the affected areas, they are relatively easy and quick to repair. We rate this event as a relatively low to medium risk.

We have rigorous engineering standards and systematic inspection processes in place for our overhead lines and towers. Also, we have an active vegetation management programme which aims to minimise the impacts of trees on our overhead lines, particularly during storm events.

3.7.6.5 66kV oil filled cables

We have 40km of oil filled 66kV underground cables left in the urban area, and have a project to replace these with more easily repaired cables in the event of a major earthquake. A major Alpine Fault earthquake could damage these cables, resulting in extended outages for significant numbers of our customers.

We rate this event as an extreme risk over the next 50 years. We plan to replace these cables with modern and resilient XLPE cable over the next 10 years.

For management of asset related risk, see Section 5.6.2.

3.7.7 Workforce availability and skills

Difficulties in finding and retaining a skilled workforce have become both a challenge and a risk for businesses across geographies and sectors. Our sector is going through an era of unprecedented change, and our business must adapt to meet the increased demand for capability and new skills. Our ability to operate and deliver our Purpose and meet our customer's future needs relies on the availability of competent, experienced, and skilled people.

Orion has a proactive approach to developing the skills and capability of our workforce to manage future requirements and address the emerging capability gap in the sector. In the immediate future, increased investment and a collective approach across the sector is needed to develop and retain the resources we need to deliver Aotearoa New Zealand's low carbon future.

Orion has instigated a range of initiatives both internally and sector-wide to address this risk, see Section 10.

We strive to be the first choice for candidates and ensure our people can build a career for now and into the future with Orion. Our focus on the wellbeing of our people, flexible working practices and a learning environment to support us on this journey.

3.7.8 Other risks

In Section 7 we identify where the load at risk exceeds our security standard and the mitigation we propose. Here we discuss two risks that are often raised, but which we rate as relatively low risk for our network.

3.7.8.1 Environmental risks

We take practical steps to prevent undue harm to the environment. Our environmental sustainability policy states our aim to be environmentally and socially responsible in our operations, and in support of this we maintain an environmental risk register.

Our environmental management system covers the sustainable use of natural resources, reduction and safe disposal of waste, the wise use of energy, restoring the environment following works, commitment of appropriate resources, stakeholder consultation, assessment, and annual audit. Our job specifications for our key service providers include requirements to identify and manage environmental risks in the work they do for us.

We have over the years invested to reduce the risks of ground contamination from oil filled transformers. Our main substation transformers have now been fully bunded to contain any spill and we have fully documented management procedures and the necessary equipment to deal with any minor spills from smaller transformers – for example, those that are pole mounted in rural areas.

Most of our 66kV circuit breakers use sulphur hexafluoride gas (SF_6) as the interruption medium. We have not found a viable alternative for this voltage. Our environmental management procedure for SF_6 gas aims to ensure we achieve our target of < 0.8% loss.

We also require our key service providers to adhere to the discovery and handling protocols for:

- asbestos
- hazardous substances
- items of archaeological significance, complying with Heritage New Zealand Pouhere Taonga Act 2014

3.7.8.2 New technologies

New technologies have the potential to transform how our network operates and enable our community to thrive in a low carbon future. We manage any risk associated with them, by planning for their introduction as much as possible, so they can be integrated into a wider 'energy ecosystem' and used in the most effective way. Examples include:

- Increased use of electric vehicles in the region will increase demand for electricity, but also introduce a fleet of batteries that could enable innovative load management techniques
- conversion of industrial heat processes from fossil fuels to low carbon energy, including electricity could also increase demand on our network, but also provide an opportunity to think about our energy system more widely and introduce a balanced approach to demand
- battery technology and energy management systems can improve the resilience of our customers and enable demand to be managed in a more nuanced way
- distributed generation, such as solar PV – this will potentially create more complex two-way flows between our network and end-use customers. We need to ensure our network can enable this to occur and facilitate the efficient and effective use and distribution of local generation wherever possible

Our risk management approach is to:

- keep up to date with technologies as they emerge
- assess the potential impacts and opportunities for our network
- understand more about our low voltage network – as this is where most two-way electrical flows will occur
- adhere to our business purpose and strategy – which is to be an 'enabler' for our customers

We are confident we can adapt our network to accommodate changing customer needs and preferences, and adopt new technologies that ensure our network is future-ready.

We are confident we can adapt our network to accommodate changing customer needs and preferences, and adopt new technologies that ensure our network is future-ready.

3.8 Our resilience

Resilience is our ability to withstand, respond to and recover from significant, especially HILP, events. It is fundamental to our ability to provide a sustainable and fit-for-purpose service for the long-term benefit of our customers and our communities.

We approach our network resilience from two main perspectives – we aim to:

- identify and reduce the impacts of future credible HILP events by how we design, construct and operate our network
- have a fit-for-purpose response and recovery capability

3.8.1 Our key network vulnerabilities

The lifelines interdependencies section, Section 3.7.6.1, describes the HILP vulnerabilities for our key network asset categories and our risk treatments and plans for them. For the purposes of this summary, our two significant vulnerabilities are:

- our outstanding risk treatments for spur assets we have purchased from Transpower since 2012. We have invested to substantially improve the safety, resilience and reliability of these assets since 2012 – and we plan to complete that investment programme over the next few years so that the spur assets meet our standards
- our remaining 40km of oil filled 66kV underground cables. We plan to replace these cables with modern resilient XLPE cables over the next ten years

The impact of Cyclone Gabrielle on electricity distribution networks underlines the need for more to be done to increase the resilience of power infrastructure.

3.8.2 Our overall resilience

There is no single measure of resilience. Assessing an EDB's resilience requires a good understanding of the key quantitative and qualitative aspects of the appropriate context and where an EDB is at in relation to that context.

Our resilience is the result of all that we do to:

- reduce the potential impacts of future HILP events – for example, we have strengthened our key substations and we have prudently invested to create a more resilient urban 66kV network and work actively to understand the effect of future events on our network
- be ready to respond and recover – for example, we have prudent operating practices for our people and service providers, we have prudent levels of key network spares, we learn and improve from our experiences of quakes, storms and other significant events, and we foster a culture that encourages our people to identify and assess relevant context and risks – and we act as reasonably practicable to treat our resilience risks

Overall, we believe we are achieving network resilience levels that are fit-for-purpose for our key lifelines responsibilities, in our local context and in the long-term interests of our customers and communities. The impact of Cyclone Gabrielle on electricity distribution networks underlines the need for more to be done to increase the resilience of power infrastructure. We recognise we can always improve and this AMP describes many of our initiatives that aim to do just that.

3.8 Our resilience continued

Our key documents that relate to our network resilience are as follows:

Table 3.8.1 Orion's key network resilience documents

Documents	Description
Asset management policy (Section 2.7)	This policy underpins our whole asset management plan and processes. Our policy arises from a good understanding of our context, our purpose and our aim to achieve what is sustainable and in the long-term interests of our customers, our community and our shareholders. Ensuring sustainable and practicable network resilience is an important policy objective for us – and this AMP outlines how we aim to continue to do that.
Asset risk management plan	This plan's topics include: • our key natural disaster risks • our rating system for our key network components most at risk • our main risk controls, and our practical solutions to reduce risk • key locations and the most likely reasons for network asset failure • our main contingency measures • our key network emergency spares
Network disaster resilience summary	An overview of how we plan, design, construct and operate our network, and our supporting infrastructure. Aims to inform Civil Defence and other stakeholders of our overall network resilience in support of wider community major incident planning.
Participant rolling outage plan	Pursuant to the Electricity Industry Participant Code 2010, this plan outlines how we respond to grid emergencies that are declared by the grid System Operator. Typical scenarios include very low hydro lake levels, loss of multiple generating stations, or multiple transmission grid component failures. Our plan outlines how we shed load when requested by the System Operator – the plan is on our website. We help to prevent cascade failure on the transmission grid when we: • help Transpower with its automatic under frequency load shedding (AUFLS) by providing a schedule of our preferred urgent load shedding locations and AUFLS provision where embedded in our network • help Transpower with its automatic under voltage load shedding (AUVLS) for upper South Island transmission constraints by providing a schedule of our preferred urgent load shedding locations and AUVLS provision where embedded in our network • provide 'blocks' of load to Transpower for emergency load shedding We aim to keep supply on for our customers, and load shedding is always a last resort after all other forms of electricity demand savings (including voluntary savings) have been exhausted.
HV Network Security of Supply Standard	This standard, see Table 5.2.2, is key to how we plan to meet customers' demand for electricity in certain circumstances.
Network physical access security plan	This plan outlines our plan to restrict physical access to our electrical network and associated infrastructure, and it supports our commitment to provide a safe, secure and reliable network for our customers and community. Our main focus is to restrict access by unauthorised personnel. Some aspects also affect authorised personnel. We aim to achieve this by: • reasonable measures to prevent access • additional measures to deter, detect and slow determined intruders at higher risk sites
Environmental risk register	This register summarises our key environmental risks.
Business unit continuity plans	Each business unit manager is responsible for their respective plan.
Contingency plans	Failures of primary network assets such as 66/11kV transformers or 66kV cables are rare on our network, but can cause significant outages for many of our customers, depending on the circumstances. To mitigate this risk, we have identified the credible failure scenarios for our primary assets and for each failure scenario we have developed a contingency plan to restore supply in a timeframe consistent with our security of supply standards. In some cases, our contingency plans identify the need to alter our network or hold additional spare assets to meet our objectives. Our contingency plans are held by our network operations team and they are updated regularly.
Communication plans	As part of our emergency preparedness, we have a Crisis Communications Plan, and Communications Plans for projects that involve significant power outages and major outage communication plans. In emergencies, we aim to keep our customers and the community informed, and we work closely with our key stakeholders in emergency management.

4 Customer experience

Photo: "Powerful Conversations" workshop participants sharing their views on our prioritisation of expenditure.

Contents

4.1 Introduction

Orion works hard to understand the needs of our customers, and give them a voice in our decision making, as we power a vibrant and energised region now and into the future.

Being close to our customers is central to our asset investment decisions and asset management practices. We seek their views on a wide range of topics reflecting the Orion Group Strategy and our approach to the management of our assets.

To find out what our customers expect of us, and where they would like us to invest to support their vision for the future, we use a range of different methods of engagement to seek diverse views and cross-check what we are hearing.

In setting our service level targets we believe we have achieved the right balance between legislative, regulatory and stakeholder requirements, and what our customers expect.

This section outlines how we engage with our customers to understand their needs and what they expect from us in terms of service levels. It discusses how we measure our performance, our performance targets and how our network performs against those targets. Our SOI also contains targets for customer service, reliability and other aspects of our business, some of which are outside the scope of this AMP.

Orion works hard to understand the needs of our customers, and give them a voice in our decision making.

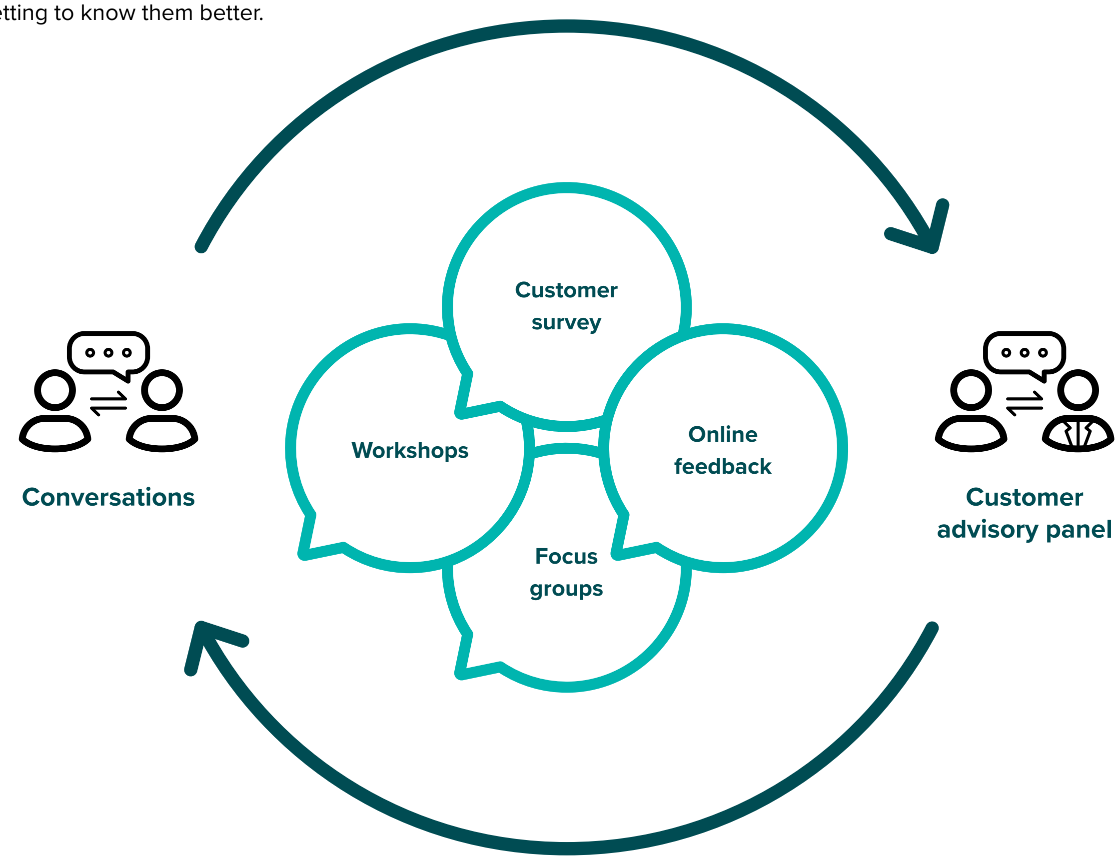
4.2 Customer engagement

As well as physically maintaining our infrastructure, keeping our network operating sustainably and delivering on our Purpose is also about knowing our customers, what their needs and aspirations are, and ensuring we contribute positively to their lives.

We do that by actively consulting with our customers and getting to know them better.

We seek out our customers' views on a wide range of topics including future investments, our customer service and how they see emerging technologies offering new ways to manage their energy consumption at home, in the workplace and on the road.

This has never been more important than it is today.



4.2 Customer engagement continued

The electricity industry is in an era of transformation, driven by the climate emergency, evolving technology and shifting customer expectations.

Our customers want affordable power, more control over where their energy comes from, and how they consume it. They are looking for flexibility, more choice, energy independence and opportunities to help New Zealand's efforts to address climate change through using renewable energy.

It's vital we adapt our business to respond to customer driven demands.

We have taken significant steps to listen more closely to our customers through many forms of engagement.

Figure 4.2.1 Our customer engagement helps Orion to:

4.2.1 Customer Advisory Panel

Orion's Customer Advisory Panel continues to provide a valuable forum for us to engage with leaders of community groups, business leaders and non-government organisations that represent the interests of a broad cross-section of our customers. With a customer advocacy focus, the Panel helps us understand customer needs, issues and service requirements.

Orion's Customer Advisory Panel provides valuable insights that inform our asset management strategy. Customers benefit from having their perspective represented in decisions about future investment and service enhancements.

4.2.2 Customer satisfaction research

Orion commissions an annual customer satisfaction survey carried out by independent researchers to measure the levels of satisfaction with our service, customers' views on our network reliability, their level of trust in Orion, and opinions on a variety of topical matters.

This is a robust survey of a representative sample of 800 urban and rural residential customers in our region. Periodically, we extend the survey to include small to medium business customers.

Because we survey a significant number of people across our region, we are able to breakdown our survey results into broad locations including urban, rural and remote rural, and targeted townships or areas where we suspect local issues may prompt views that differ from the overall result.

This enables us to identify areas where satisfaction is below average and increased engagement with the local community or investment in our network would be welcomed.

From time to time we commission Focus Groups to provide deeper insight into customer's thinking on issues such as pricing options, specific network investments or our communications.

We also commission an annual follow-up survey of callers to our Customer Support team, to measure the level of customer satisfaction with our response to their enquiries.

4.2.3 Materiality research

In FY22 we added a materiality study into our research mix to find out what a cross-section of our stakeholders would like the Orion Group to focus on.

The materiality assessment helped to identify and prioritise material issues for the Orion Group. These insights are being considered in our asset management planning and reporting.

4.2.4 "Have your say Orion"

In 2022 we established an online community engagement forum, using the internationally recognised Bang the Table platform. "Have your say Orion" enabled us to engage in two-way dialogue to seek our customer's views on a range of topical matters and keep impacted customers up to date on major projects.

With "Have your say Orion" we have created a custom-built website and a range of modern digital experiences to interact on a range of topics with our unique community.

4.2.5 "Always-on" Customer Support team

Our 24/7 Customer Support Team talks with our customers on a daily basis about the service they receive. Through emails and more than 1,800 calls per month we gain a rich understanding of what's important to our customers.

These conversations enable us to respond to the immediate interests of our customers, and identify any prevalent concerns or opportunities to continuously improve our service.

4.2.6 Resolving customer complaints

Our management of customer complaints also provides Orion with insights on customer satisfaction with our performance, and highlights opportunities to improve our service or operational efficiency.

The principles which underpin Orion's approach to resolving customer complaints are:

- We treat customers with respect
- We seek to understand the customer's issue, from their point of view, and acknowledge their concern
- We will review the matter in a timely manner and keep the customer informed about the process and progress
- Each case is viewed on its own merits
- We are fair in our approach, balancing the customer's perspective with Orion's interests and those of the wider community
- We resolve complaints promptly

A complaint is where a customer is not satisfied with our service, or our response to an issue they have raised with us. Complaints may relate to charges, service issues, outages, the way we dealt with the customer, our processes, the location of Orion equipment, concerns about electromagnetic radiation, site reinstatement, equipment damage, or issues with third party service providers.

Orion's Customer Support team operates 24/7 and all team members are trained on how to recognise and respond to customer complaints.

Complaints can be made via phone, website, email or through Orion people. If not immediately resolved satisfactorily with the customer, our Customer Support people record the details of the complaint, and escalate the complaint to a dedicated resolutions specialist, advising the customer of our resolution process and when they can expect to be contacted to discuss the matter in more detail.

We keep an accurate, full record of all interactions relating to complaints in our online Incident Management system. This ensures everyone dealing with the complaint is aware of the background and current position, and provides a record of events should the matter become a legal or insurance issue, or is escalated to Utilities Disputes Ltd.

In accordance with clause 11.30A of the Electricity Industry Participation Code, customers are routinely advised through multiple channels of their option to escalate their complaint for independent arbitration by Utilities Disputes Ltd.

Orion credits its empathetic, pragmatic, and speedy resolutions process, combined with real human interaction, for its record of successfully resolving customer complaints.

Our empathetic approach to complaint resolution ensures customers understand that we acknowledge their complaint, we understand their point of view and we will do our best to find a resolution that works well for both parties. Keeping in mind the complicated and stressful issues Cantabrians have had to deal with in the last decade we are mindful of being kind and caring.

Three resolution specialists who are members of the Customer Support team oversee, record and follow up on complaints directly with customers or with Orion people who are handling complaints.

We convene our Complaints Forum as needed to consider escalated complaints and decide on the course of action to be taken, including any payment of compensation.

The Complaints Forum consists of our Head of Customer and Communications, Eternal Engagement Lead, GM Commercial, GM Electricity Network or delegate, Customer Support Manager and the Customer Support complaints specialist handling the complaint.

We aim to resolve complaints within five working days, where possible and typically all complaints and queries including those lodged with the Utilities Disputes Limited are resolved within an average of 1.8 days, with all customer complaints resolved within 20 working days. As testament to the effectiveness of Orion's customer complaints resolution process, in the year to March 2022 Orion had no deadlock complaints with independent adjudicator, Utilities Disputes Ltd.

To help monitor performance against targets and identify systemic issues our Customer Support complaints specialists produce a monthly record of complaints, compensation claims and inquiries to be reported via the Communications and Engagement team's monthly report.

Reporting includes the average time taken to resolve complaints, the number and nature of the complaints, per month. The total amount of compensation paid, and the nature of the payments. This can help identify where customers believe we can make improvements. The resolutions team has consistently surpassed Orion targets for complaint resolution over the past five years. Orion credits its empathetic, pragmatic, and speedy resolutions process, combined with real human interaction, for its record of successfully resolving customer complaints.

4.2.7 Major customer engagement

After a pause during the COVID-19 pandemic, all our major customers are again invited to seminars where we take the opportunity to engage with them on key matters. These are people who run intensive power dependent businesses, from schools, supermarkets and malls to dairy processing plants and printing businesses.

4.2.8 Key stakeholder engagement

We regularly meet with key stakeholders and key influencers in the business community, our shareholders, Community Boards and local MPs to seek their views on our performance, future direction, and options we are considering.

4.2.9 Customer engagement over major projects

We have responded to increasing community expectations for more extensive communications about major projects affecting their service.

Where major projects have a significant impact on the community, we provide enhanced levels of communication directly with our customers and key community stakeholders. This can include Work Notices with details of the projects, the benefits and the impacts on their service during the work along with a point of contact, and updates via emails and texts. We also provide presentations to local Community Boards, run local advertising and provide information via community social media channels.

4.2.10 Customer engagement over new connections

In response to record numbers of new customers joining our network and customer feedback, we have reviewed our approach to planning and managing new connections.

We now provide customers with a user-friendly online portal to enter their requests for connection. The portal enables customers and electricians to check on where new connections requests sit and address any hold-ups as they progress through the process. Along with initiatives to streamline the process, this has reduced connections timeframes, and improved customer communications.

4.2.11 Media, sponsorship and promotional events

Media releases, sponsorships, trade shows, public exhibitions and social media are used to promote public safety messages, news about power outages and advice on future technologies, along with an invitation to provide us with feedback. These include:

- Media releases, briefings and interviews
- Facebook posts and LinkedIn updates
- Sponsorships and partnerships that enable us to engage with our community on important power matters, and support energy innovation, such as the Orion Energy Accelerator programme
- Displays at trade shows for the farming and general community

4.2.12 Advertising

Through online, newspaper, magazine, billboard and radio channels our advertising campaigns focus on encouraging behaviours that have an impact on maintaining our network reliability and public safety:

- The need to trim trees away from power lines – metro and rural versions
- Farm safety around power lines
- DIY safety
- Encouraging people to come see us to discuss safety around power lines at local A&P shows

We also use advertising to provide the public with information and reassurance during crisis events, such as the COVID-19 pandemic.

4.2.13 Website

Our website provides up to date information, real-time details of power outages and online customer service functionality.

We have enhanced the information provided on our power outages page to provide customers with updates on the cause of outages, and our progress with restoration.

4.3 What our customers have told us

Our customers have provided a useful picture of what is important to them, and where they would like us to concentrate our attention and investment. Consistently throughout our conversations, in research and Advisory Panel discussions customers are aligned with and have endorsed the strategic focus and guiding principles of our asset management strategy.

This section sets out the latest views of our customers gathered from our various customer engagement activities.

4.3.1 Customer satisfaction research results

We gather a wealth of information on what our customers think of our service. Figure 4.3.1 shows the key results from our latest annual customer research surveys.

Figure 4.3.1 Key results from our Annual Residential Customer Satisfaction survey, 2022; and Customer Calls research, 2022

Orion's overall performance

NPS +35
Orion's Net Promoter Score

8.3 AVG.
0—10 scale

33%
of respondents rate performance as a **10** on a 0—10 scale

Key perceptions of Orion

80%
agree **Orion is capable and effective**

80%
agree **Orion carries out its duties very well**

77%
agree **Orion maintains the electricity network well**

70%
agree **when the power goes out, Orion gets on to fixing it quickly**

64%
agree **Orion acts in the interest of local residents**

41%
agree **Orion takes their customers' views into account in its decisions**

37%
agree **Orion is well-prepared for future natural disaster situations**

37%
agree **Orion is prepared for a very different future for electricity**

Awareness and perceptions of Orion

37%
Awareness of Orion

93%
Satisfied with reliability of power supply

88%
Level of trust in Orion

47%
Aware of the Orion website

35%
Aware of the Orion Customer Support service

94%
Had a good experience calling our Customer Support team

4.3.2 Communications

Our customers have also told us how they would like us to communicate with them about planned outages, and when. In general, residential customers would like personal direct communication about upcoming outages, a week or so before the event. They like to know what the outage is for, and how they will benefit. They also want us to respond to any concerns they raise about community impacts. They prefer one big, all day outage over multiple shorter outages over an extended period.

Business customers tell us they need more notice to plan for interruptions to their operations.

4.3.3 Safe, reliable, resilient network

The key views of our customers on the safety, reliability and resilience of our network are:

- **That our network is safe is “a given” for our customers.** We recognise and respect the high level of public trust in the safe operation of our network.
- **In all our conversations with customers, the importance of being provided with a reliable service is an abiding theme.** Customers view reliability as a “hygiene factor” and tell us that focusing on providing a reliable service should be fundamental for Orion. They want us to continue to invest to maintain our standard of reliability, although not at any cost. Most customers are highly satisfied with Orion’s current levels of reliability, and do not support investment to increase reliability if that comes with increased prices.

  Our November 2022 annual survey of residential customers found 93% were satisfied with the reliability of their power supply. See Figure 4.3.1.
- **Resilience is very important to our customers.** Our customers tell us Orion’s investment in resilience represents good value for them. Customers have low tolerance for long outages, and want Orion to invest in resilience with this in mind.

4.3.4 Energy equity: access and affordability

In conversations with our Customer Advisory Panel they tell us many of our customers are struggling to pay their power bills. We are having ongoing discussions with our customers to better understand the issues of energy equity and developing ways to help those in need. We will also explore customers’ views on the cost impacts of gearing our network up for the future on customers’ bills.

4.3.5 Health and safety

Customers have asked us to take a “common sense” approach to managing safety risks. They say protecting human life and avoiding injury is paramount. They believe Orion should balance the costs and risks associated with safety issues when addressing them.

The success of our public and business safety education campaigns is positively reflected in the number of occasions Orion is asked for a close approach consent from both residential and commercial customers. At consistently around 4,500 requests per year this is among the highest rates for EDBs in New Zealand. In FY22, we introduced a semi-automated application process for close approach, high load and standover consents that has improved our operational efficiency and supported safety outcomes.

4.3.6 Materiality

The areas our stakeholders interviewed as part of our materiality survey rated the highest were:

- Health, safety and wellbeing
- Sustainable financial performance
- Climate change
- Quality management
- Customer experience

This materiality assessment is providing valuable insights to inform our decision making.

4.3.7 Capability and competence

Our customer research shows people are very confident in Orion’s current capability and competence in management of the power network. As shown in Figure 4.3.1, among a range of strongly positive scores in our latest Customer Satisfaction survey, 80% agree that Orion is capable and effective in the management of our network, and 80% say we carry out our duties very well.

4.3.8 Future focus

In our Customer Advisory Panel sessions Orion has been encouraged to have a strong focus on the future – to make sure our network is ready for customers to transition to low carbon energy sources, expand their energy choices, and to be prepared for climate change.

In our annual customer survey we found customers are less confident in our readiness for future natural disasters and preparedness for the future. Only 37% agree that Orion is prepared for a very different future for electricity where customers have more choice about where they get their power from, how they use it and share it with others. Uncertainty, unawareness and lack of communication drive this perception.

This is not an issue that is peculiar to Orion. The general public, regulatory and political stakeholders have noted the sector needs to simplify and be more proactive and cohesive with its communications about the future of energy in New Zealand. In recent industry research more than half of those surveyed said it was important that sector companies do more to communicate the steps they are taking to address climate change.

We have put in place a network transformation team to define and design the network to meet our customers’ future needs. Set in motion in 2022, our Network Transformation Roadmap is positioning Orion to manage the risks and make the most of the opportunities the future presents. For Orion, and the industry, communicating our plans and vision for the future to stakeholders is a priority.

4.4 Turning listening into action

We have instigated a range of initiatives that translate what we have learned in our conversations with customers and other stakeholders into action. We will continue to seek our customer and stakeholder's views on our core network services and future direction as our Group Strategy evolves.

What we heard	What we are doing
Customer service • Give us more information when the power goes out • Make our day to day transactions, easy and quick	• Implemented a Customer Relationship Management tool (CRM) to streamline repeat transactions • We now communicate proactively with customers before significant planned outages, including Transpower GEN notices
Safe, reliable, resilient system • Improve our reliability in Banks Peninsula • Tell us how you are preparing for a changed energy future	• Refurbished the power line supplying Akaroa from Duvauchelle • Participating in industry wide communications about future network preparedness • Increasing communications about future network plans • Replacing oil filled cables
Health & safety • Keep us safe, but not at any cost	• Increased the frequency and reach of our public safety education campaigns • Collaboration with EDB colleagues on ENA's national tree trimming advertising campaign
Sustainability • Take action to address the climate emergency	• Published our report: *Climate Change Opportunities and Risks for Orion* • Achieved carbon neutrality for corporate emissions by June 2022 • Provide dedicated focus on gearing up for a changed energy future
Affordability • Help address energy hardship	• Supported Community Energy Action and Energy Mad initiatives • Supported Orion Energy Accelerator winner, Empower Energy, to explore a promising solution to energy poverty • Fostering initiatives to encourage energy efficiency a focus area in Orion Group's Strategy, **Here for Good**.
Future network • Reassure us you're ready to support our future needs • Be ready for change	• Joined with other industry organisations in public information channels that explain our role in the energy future • Developed the Orion Network Transformation Roadmap • Sharing our network developments including on social media channels

4.5 Performance measures

This section sets out how we rate in an dependent assessment of our performance using the Asset Management Maturity Assessment Tool (AMMAT). We also measure our performance against the targets we set ourselves as well as those set by our regulators.

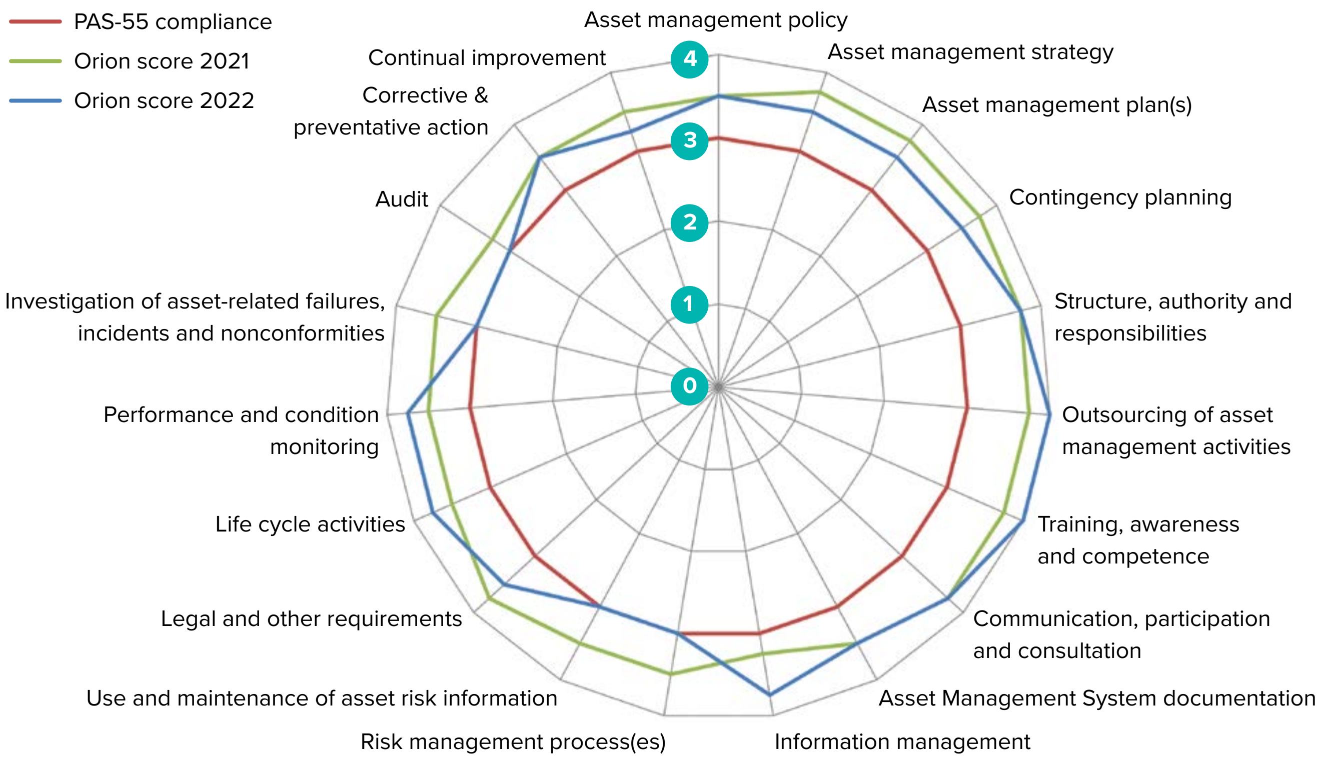
As part of the Commerce Commission's Information Disclosure requirements, EDBs must provide an overview of asset management documentation, controls and review processes using an instrument known as the AMMAT.

An overview of the general criteria the standard requires to be met for each maturity level is shown below.

Figure 4.5.1 AMMAT maturity levels

The elements required by the function are not in place. The organisation is in the process of developing an understanding of the function.	The organisation has a basic understanding of the function. It is in the process of deciding how the elements of the function will be applied and has started to apply them.	The organisation has a good understanding of the function. It has decided how the elements of the function will be applied and work is progressing on implementation.	All elements of the function are in place and being applied and are integrated. Only minor inconsistencies may exist.	All processed and approaches go beyond the requirements of PAS 55. The boundaries of Asset Management Development are pushing to develop new concepts and ideas.
Maturity Level 0	**Maturity Level 1**	**Maturity Level 2**	**Maturity Level 3**	**Maturity Level 4**
Innocence	**Aware**	**Developing**	**Competent**	**Excellent**

Figure 4.5.2 Orion's AMMAT scores



In July 2022 Orion again engaged WSP Opus to undertake an independent AMMAT assessment. WSP Opus determined that Orion has continued to improve its asset management system and believed Orion has engendered the right organisational culture change and approach for effective long term asset management operations.

While remaining compliant in all categories and bettering our score in five categories, Orion has narrowly slipped back in eight categories. Orion is focused on enhancing operational excellence and has put in place a plan to identify root causes and establish a programme to lift these ratings back up to previous levels.

Our excellent score for **Outsourcing of asset management activities** reflects our establishment of a Primary Service Delivery Partner model, and that for **Training and awareness and competence** reflects Orion's leadership in this area. For full results see Appendix F, Schedule 13.

4.5 Performance measures continued

4.5.1 Performance against targets

Table 4.5.1 provides a summary of we have performed against our targets for the key measures related to management of our assets, customer service and environment. These targets are a sub-set of our overall Orion Group targets, set out in our SOI.

Table 4.5.1 Summary of performance against targets

Orion Group Strategy	Asset management objective	Measure	FY22 targets	FY22 performance	Achieved?	FY23-FY25 targets
Facilitating decarbonisation and hosting capacity at lowest cost	Sustainability and environment	% of transformers monitored across Orion's LV network	3%	3.6%	✓	6%, 9%, 11%
		SF_6 gas lost	< 0.8% loss	0.32% loss	✓	< 0.8% loss
		Grams CO2e per MWh delivered – excludes distribution losses	Reduction towards 2030 target	219g – which is a reduction of 129g from FY20	✓	< 200g grams CO2e per MWh delivered
Investing to maintain our network	Network performance and power quality improvements	SAIDI Unplanned	Limit < 84.7	42.9	✓	Limit < 84.7
		SAIDI Planned	FY21-25 limit < 198.81	24.9	✓	5 year FY21-25 limit < 198.81
		SAIFI Unplanned	Limit < 1.03	0.60	✓	Limit < 1.03
		SAIFI Planned	No limit	0.07	n/a	No limit
		Unplanned interruptions restored within 3 hours	> 60%	65%	✓	> 60%
		Power quality: number of escalated customer complaints	< 60	23	✓	< 60
		Power quality: number of proven harmonics or distortion complaints	< 4	2	✓	< 4
	Resilience	Introduce the methodology of the EEA Resilience Guide	n/a	n/a	n/a	End of FY24
	Safety	Safety of Orion Group employees	≤ 4 serious events	3 serious events	✓	≤ 4
		Safety of service providers	≤ 4 serious events	1 serious event	✓	≤ 4
		Safety of the public	0 serious events	1 serious event	✗	0
Being a force for good	Customer experience	Customer Support caller satisfaction	> 85%	100%	✓	> 85%
		Net Promoter Score	> 40	+36	✗	> 40
Creating the preferred workplace	Future capability development	Employee engagement	> 65%	63%	✗	> 65%
Fit for purpose capital structure	Ongoing operational optimisation	Capital expenditure per MWh	Target to be set			
		Operational expenditure per MWh	Target to be set			
		Operational expenditure per ICP	Target to be set			

4.5.2 Facilitating decarbonisation and hosting capacity at lowest cost

Sustainability and environment

We are a passionate advocate for low carbon energy and are committed to reducing our carbon emissions, and helping others to do the same. This is pivotal to Orion delivering on our Purpose to power a cleaner and brighter future with our communities.

4.5.2.1 LV network monitoring

Our Low Voltage (LV) network will increasingly need to support new and more complex two-way power flows as customers progressively adopt alternative ways to power their homes, businesses and vehicles. We are installing new equipment in Christchurch residential areas that enables us to monitor the use of power in near real time, at street level.

These low voltage monitors sample power flows and voltage at 10 minute intervals, generating a wealth of data that will allow us to see and respond to changes of activity on the network. Having visibility of how our network is being used at this granular level will also help us provide customers with a more flexible, dynamic range of choices for managing their energy needs. See Section 7.4.2.1 for more information on our LV monitoring project.

Performance against target

In FY22 we installed 202 monitors, bringing the total per cent of our transformers monitored to 3.6%, .6% above our target.

4.5.2.2 Management of SF_6

Orion uses sulphur hexafluoride (SF_6) in our network as an electrical insulator and arc suppressant in some circuit breakers rated 11kV and above. SF_6 is an extremely potent greenhouse gas. 1kg of SF_6 is equivalent to 22,800kg of CO_2. We treat it as a climate risk and design and operate our network to avoid the potential for it to be emitted.

We have a programme to reduce our SF_6 losses by introducing a replacement schedule for the gaskets on all our 66kV circuit breakers and we are looking to phase out circuit breakers using SF_6 at 11kV.

Orion is also working to reduce the introduction of new SF_6 into the network, and we are trialling a vacuum insulated 66kV circuit breaker as part of our investigations.

4.5.2.3 Lowering our carbon footprint

We have instigated a range of initiatives to more accurately measure and reduce our carbon emissions. These include:

- Incorporating more battery-powered electric vehicles (BEVs) and Plug-in Hybrid Electric Vehicles (PHEVs) in our vehicle fleet
- Trialling remote control of our EV chargers, to avoid charging them at the peak times when New Zealand's current energy mix relies heavily on coal
- Using 100% biodiesel alternative fuel made from used cooking oil in our generators
- Using drones and remote switching technology to reduce field crew travel with its reliance on fossil fuels
- Designing our network so equipment supply chains are short, or circular where possible
- Established a native tree planting programme to off-set our carbon emissions
- Extending our footprint to take account our people working from home
- Setting up two satellite offices closer to where many of our people live to reduce our commuting emissions
- Installing solar panels on the roof of our Wairakei Road offices delivering a potential 173MWh/year

We expect to see these measures to also reduce our operational costs, particularly as the cost of fossil fuels increases as forecast.

Performance against targets

We are committed to minimising Orion's SF_6 emissions and carefully monitor and report losses. We have a self-imposed target of less than 0.8% annual loss to the atmosphere of the insulating gas SF_6.

Orion reports to the Ministry for the Environment on our SF_6 loses, and we meet the requirements of reporting by measuring our losses to down to the nearest 50 grams of SF_6.

We achieved our FY22 target for SF_6 loss. We did not achieve our target for grams CO2e per MWh delivered as this had been based on a COVID-19 year as a benchmark, and our target has been reset to reflect resumption of our usual operations.

We are committed to reducing our operational footprint and to enable others to reduce their carbon emissions. We are developing the ability to track embodied emissions per MWh delivered, and carbon reductions we have enabled around our region.

For more information about Orion's carbon emission targets and performance, refer to our Climate Change and Opportunities Report, available on our website.

4.5.3 Investing to maintain our network

Network performance and power quality improvements

We measure our network performance and power quality through a variety of measures that directly relate to the customer experience.

4.5.3.1 Network reliability – SAIDI and SAIFI

Our network reliability measures are as required by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012. These are:

- **SAIDI** – System Average Interruption Duration Index – measures the average number of minutes per annum that a customer is without electricity
- **SAIFI** – System Average Interruption Frequency Index – measures the average number of times per annum that a customer is without electricity

SAIDI and SAIFI measures planned and unplanned interruptions of a duration longer than one minute on our subtransmission and high voltage distribution system.

The SAIDI and SAIFI limits set by the Commerce Commission are thresholds that going beyond will result in a quality breach, which may lead to fines of up to $5 million. Unplanned interruption limits apply annually, which means that any year the unplanned limit is exceeded will result in a breach.

Performance against targets

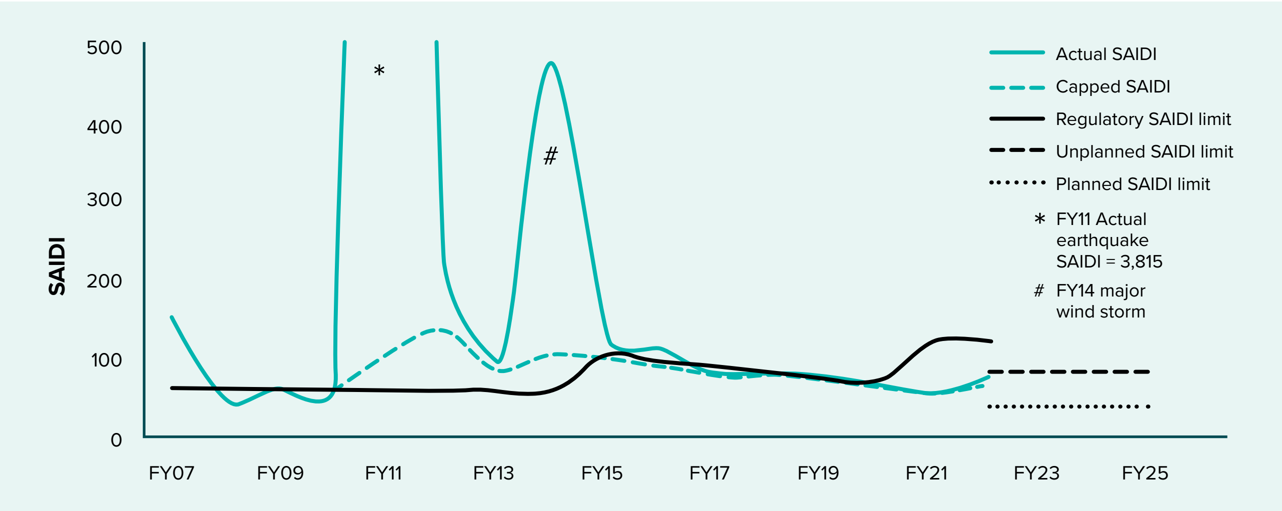
As shown in Figure 4.3.1, in our November 2022 annual survey of residential customers, 93% were satisfied with the reliability of their power supply.

The details of our performance in network reliability for FY22 are shown against our targets in Table 4.5.1. We achieved our network reliability performance targets and were under our limits for unplanned SAIDI and SAIFI.

Our targets and limits for SAIDI and SAIFI for FY21-FY25 include separate targets and limits for planned and unplanned events, and an extreme event measure that relates to identification and reporting of rare events.

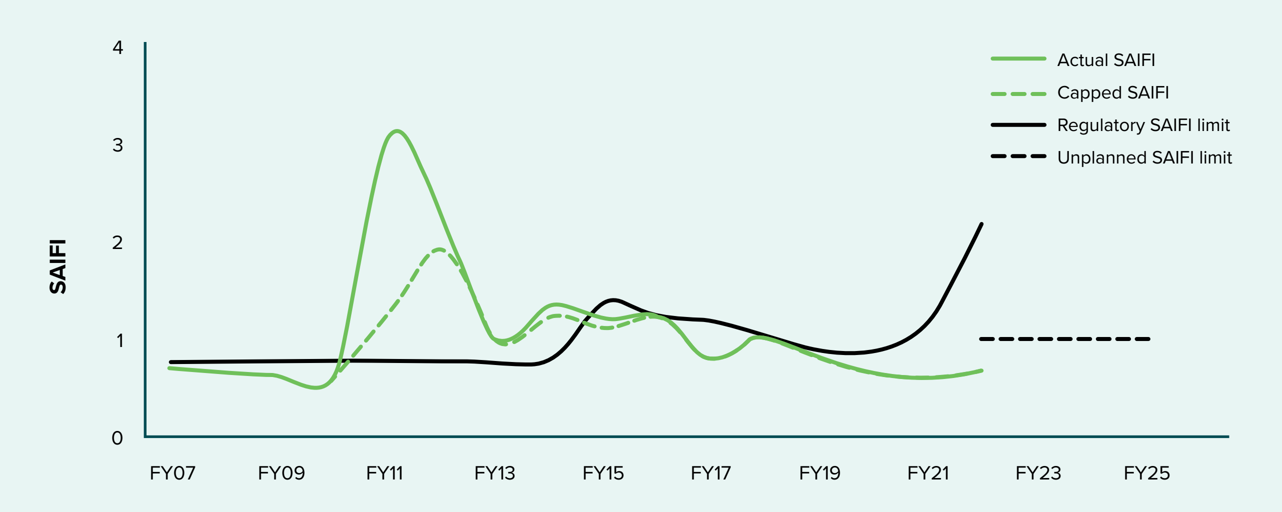
Our historical performance and future targets are shown in Figures 4.5.3 and 4.5.4.

Figure 4.5.3 SAIDI history and future limits



4.5 Performance measures continued

Figure 4.5.4 SAIFI history and future limits



Comparison by cause and asset class

Figures 4.5.5 and 4.5.6 show a further breakdown of SAIDI and SAIFI for FY22 compared to the five year averages by asset class and event cause. Our 11kV overhead network has always had the highest impact on reliability. The performance of assets such as communication and control systems isn't specified as this is inherently captured under switchgear, protection or transformers. FY22 data of interest includes:

- There was one capped wind event for SAIDI
- There were three significant weather events that were not capped, resulting in an increase in weather related SAIDI and SAIFI compared to the 5 year average
- 11kV overhead was the only asset category with SAIDI higher than the 5-year average. This is linked to the extra weather events compared to previous years. Programmed outages have increased due to an increase in the number of scheduled works that required a planned outage. We have also seen our service providers opting for an outage instead of carrying out live line work which has also contributed to the increase

See Section 6 for the maintenance and replacement strategies needed to maintain performance.

Figure 4.5.5 SAIDI by asset class and by cause

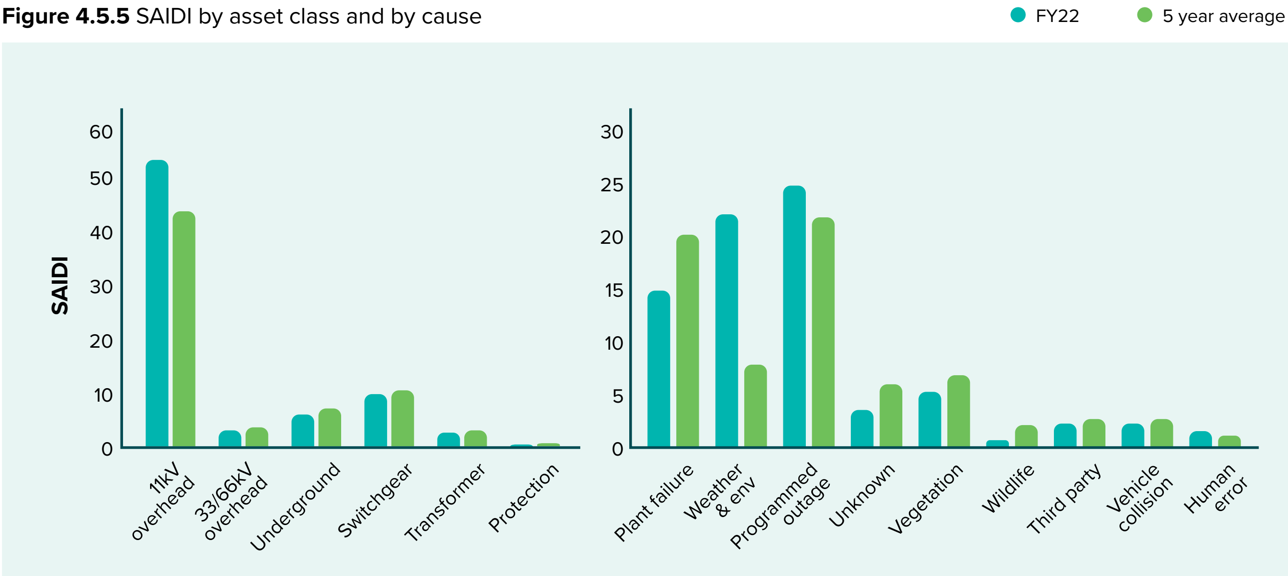
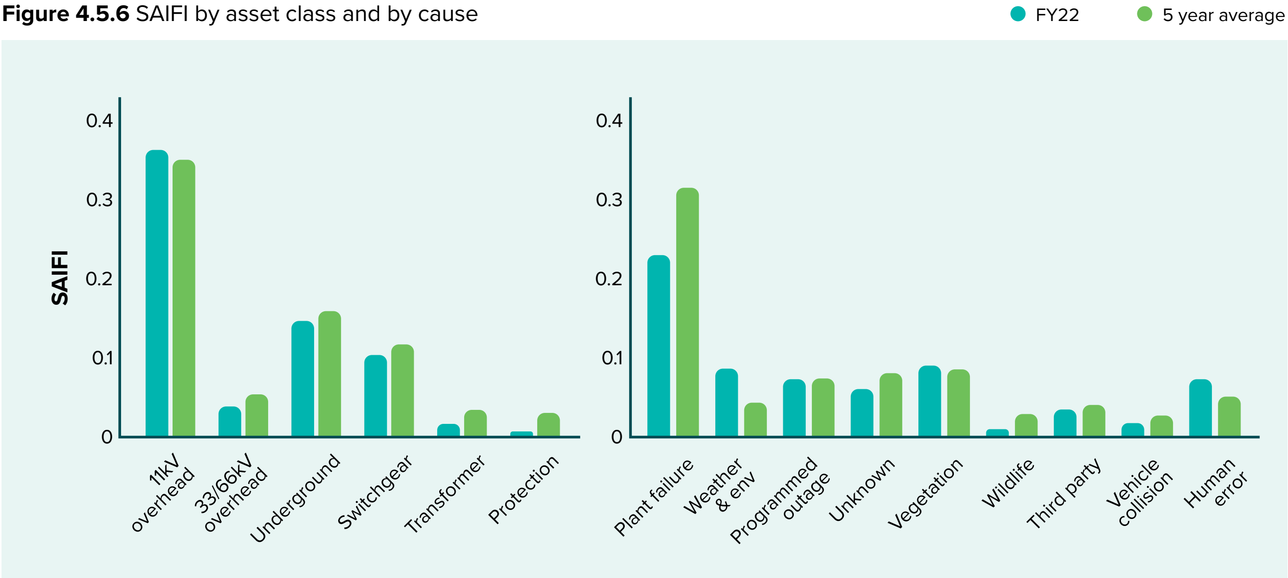


Figure 4.5.6 SAIFI by asset class and by cause



4.5.3.2 Unplanned interruption restoration

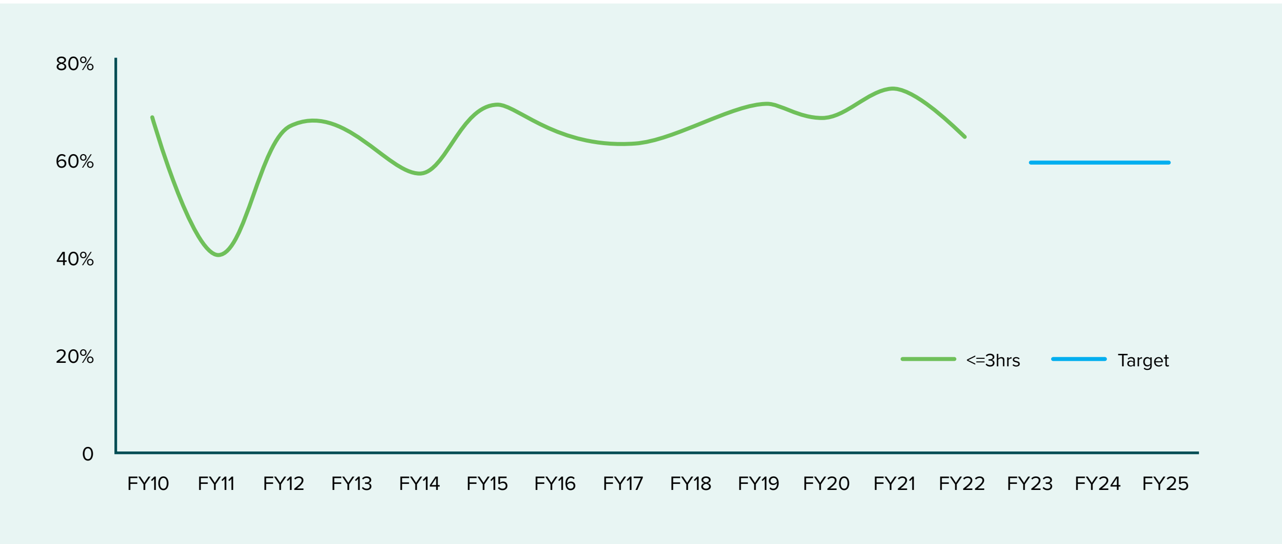
We have engaged an emergency service provider to manage our distribution asset spares and provide adequate response to any event on our network.

Larger scale network events have a significant impact on restoration times, as weather conditions and the number of faults occurring simultaneously affects our response time. High-impact weather events such as snow storms and high winds can create numerous faults across the network which can take an extended time to repair. As shown in Figure 4.5.7, between FY10-FY14, we had a number of such events with earthquakes, snow storms and very high wind events which had an impact on the restoration times.

Performance against target

With improvements in fault indication and the installation of a greater number of remotely controlled devices across the network, we expect the trend to show continued improvement over time as we can more quickly locate faults and restore supply. Our target and performance in Table 4.5.4 shows we achieved 65% restoration within three hours in FY22, above our target of > 60% restoration within three hours. This has slightly decreased from FY21, because of the extra weather events experienced in FY22.

Figure 4.5.7 Unplanned interruptions – % restored in under three hours



4.5.3.3 Power quality

Ensuring the quality of the power delivered by our network plays an important role in delivering a safe, reliable and resilient power supply to our customers.

Monitoring voltage quality

To ensure we meet the requirements of the Electricity (Safety) Regulations 2010, Orion has 33 permanently connected Dranetz power quality analysers, which constantly monitor and track power quality performance across our network. This includes at the extremities of our network, where supply issues are most likely to be experienced. Our analysers monitor a full range of network voltages between 230V and 66kV. A range of parameters are measured which define the quality of voltage, current, harmonics and event capture.

This monitoring has enabled us to build a database of the power quality performance across our network that provides a benchmark for performance across a range of conditions and scenarios. It also enables us to readily identify changes and issues arising, which prompts more analysis and if necessary, corrective action.

We measure the two key performance attributes of power quality that we can influence:

- Voltage supplied to customers – our network is designed and operated to meet the standard New Zealand low voltage, at 230Volts +- 6%, as per Regulation 28 of the New Zealand Electrical Safety regulations 2010.
- Harmonic levels or waveform distortion present in the power supplied to customers – we use harmonic allocation methods defined in joint International Electrotechnical Commission (IEC)/Australian/ New Zealand standards to determine acceptable customer levels of harmonic injection. These allow each customer to inject a certain acceptable amount of harmonic distortion depending on the capacity of the power supply at their premises.

Monitors deployed

A mixture of devices are used to measure a range of different power quality parameters which include voltage indices. We have a dedicated power quality monitoring program. Two types of monitors are used:

- **Permanent power quality monitors** – installed to monitor a range of different voltage levels. Generally, these have been installed at the end of our most vulnerable feeders to ensure that the up-stream network is preforming as designed.
- **Portable class A units** – used for power quality investigations which are generally customer driven.

Response to power quality complaints

Orion operates a 24/7 Customer Support team that fields all customer calls, and the team escalates power quality issues to a specialist team who engage directly with the customer to make an initial assessment of possible cause or initiate further investigation.

If needed, we actively investigate by first sending an Orion operator to the customer's premises to conduct preliminary assessment of the situation. Often the cause is identified at that point and rectified. If further investigation is required, we install power monitors, which provide an accurate record of performance over time. If our network is found to be at fault, rectification may include upgrading equipment or a conductor, or reconfiguring of our network in the interim while we develop a long-term engineering solution.

Of the issues raised around 20% are Orion network related and often matters at the customer's premises are found to be the cause of the issue. We work closely with customers or their representative to gain an accurate understanding of the issue, and can provide advice on avenues for further investigation by their service provider, or suggestions for how the issue might be rectified.

When non-compliant voltages are detected through either active network monitoring, customer complaints or power quality investigations, the degree of non-compliance is assessed, and an engineering solution developed to mitigate further violations. When the voltage issue has been identified by a customer, they will be notified of the works being carried out to rectify this issue.

Improving practices

Orion has increased its power quality monitoring budget to extend our view of the network. New low voltage monitor technologies are being deployed at most of our new ground mounted substation sites.

We are also developing low voltage models to identify areas of our network which are at risk of breaching voltage requirements. Where compliance issues are identified, field monitoring may be carried out to validate results before initiating works to rectify voltage issues.

Performance against target

We achieved our targets for FY22.

Resilience

4.5.3.4 Resilience

Resilience is the ability of our network, our people and systems to respond to rare but major events such as earthquakes and wind and snow storms.

A more resilient network will limit the initial impact and be adaptable enough to reduce the time to recover from major events and will enable faster than otherwise restoration of power for those customers experiencing outages. We currently do not have a target or measure for resiliency. In FY24 we aim to introduce the methodology of the EEA Resilience Guide to measure our performance in this important service attribute.

Safety

4.5.3.5 Safety

We are committed to collaboration across the Orion team to provide a safe, reliable network and a healthy work environment around our assets. We take all practical steps to minimise the risk of harm to the public, our service providers and our people. Maintaining a safe and healthy working environment while working on and near our assets benefits everyone and is achieved through collaborative effort.

We report all employee injury and public safety events that are asset related via Vault (safety information management system) and collect similar statistical incident data from our service providers. These service provider statistics, our own statistical data and our incident investigations, enable us to provide our people and those of our service providers with indicators of potential harm when working on and/or near our assets.

Performance against target

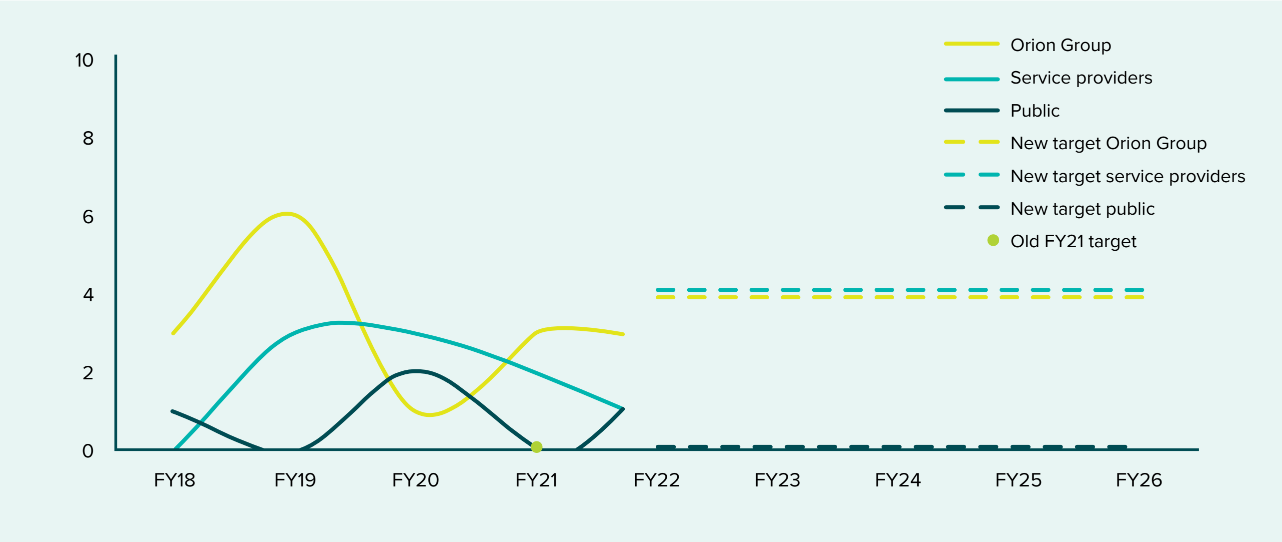
While achieving our targets in all three categories, we had a total of five safety events in FY22, three involving Orion Group employees, one involving an employee of our service providers, and one involving a member of the public. None of these events resulted in serious injury.

WorkSafe was notified of these events, which were:

- A Connetics employee received an electric shock from contact with a low voltage cable
- A Connetics employee received an electric shock while testing circuit breakers at a zone substation
- An Orion network operator received a minor electric shock while replacing a distribution box cover
- An employee of one of our service providers received an electric shock while relocating a distribution cabinet
- A civil contractor, not engaged by Orion, came into contact with our low voltage network

We will continue to focus on improving the effectiveness of the control of critical harm. Our asset maintenance and replacement programmes are fundamental to ensuring safety targets relating to assets are met in the future.

Figure 4.5.8 Safety performance – serious event trend and new targets



4.5.4 Being a force for good

Customer experience

We established measures and targets for our performance in customer service for the first time in FY21. They measure and set ambitious targets for our performance in two key areas:

- **Customer satisfaction with their calls to our Customer Support team** – more than 1,800 customers call our Customer Support team each month and it is important they come away from the experience with the information they need, and feeling positive about the experience. Independent researchers follow up with calls to customers who have recently contacted us, and seek their feedback.
- **Net Promoter Score** – we use an adapted version of a widely recognised metric that is traditionally used for retail organisations, which remains relevant in a regulated monopoly context. We believe that after their experience with Orion, our customers should be left feeling positive about us, with good word of mouth to their friends. With the New Zealand NPS rating for the power industry at +20 in FY21, our target reflects our goal to have loyal customers who rate Orion in the "GREAT" NPS range.

Performance against targets

We exceeded our targets for customer satisfaction with calls to our Customer Support team, and our Net Promoter Score.

In FY22 we established regular measurement of employee engagement and implemented programmes to boost individual, team and overall operational performance.

4.5.5 Creating the preferred workplace

Future capability development

Capability underpins operational performance, sustainability and operational efficiency.

Orion focusses on accelerating our capability to ensure we operate an efficient business that does all it can to provide an affordable energy service.

Orion's efforts to accelerate our capability are reflected in two measures: an employee engagement score and three "value for money" metrics.

4.5.5.1 Employee engagement

In FY22 we established regular measurement of employee engagement and implemented programmes to boost individual, team and overall operational performance.

Performance against target

In the course of FY22 we saw a 3% increase in employee engagement from our original benchmark survey, moving us closer to our target of 65%.

4.5.6 Fit for purpose capital structure

Ongoing operational optimisation

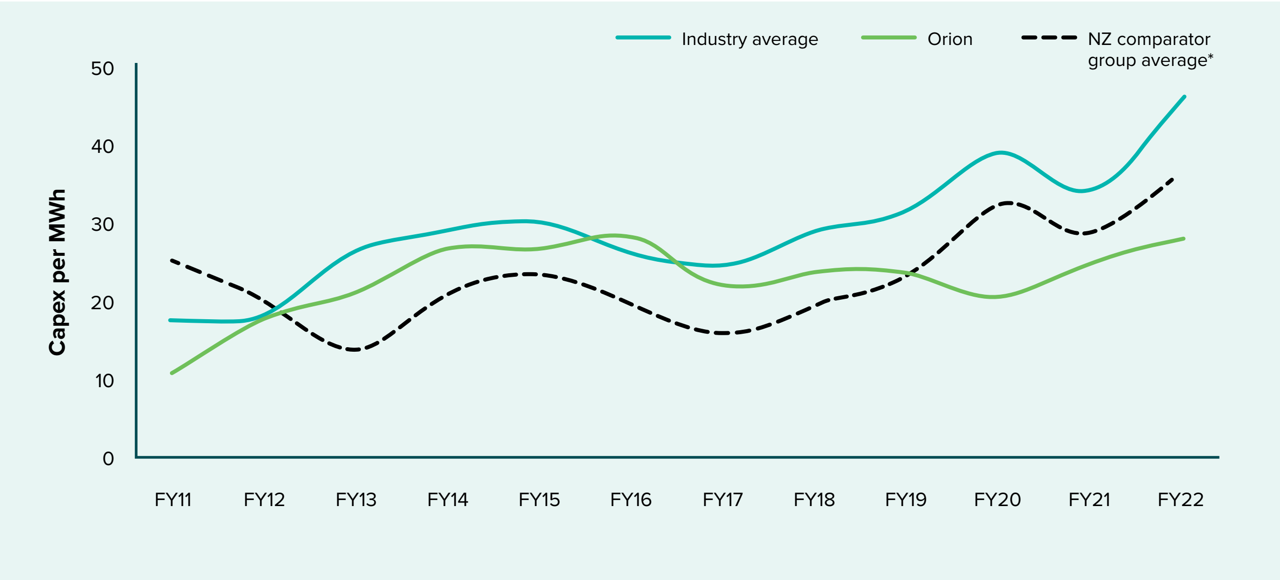
Capital expenditure per MWh

Figure 4.5.9 compares our performance for capex per MWh with both average industry performance and a subset NZ comparator grouping. The sharp increase in our capex expenditure immediately following the 2010 and 2011 Canterbury earthquakes through to around FY17 is clearly visible.

The industry average and the subset NZ comparator group show an increasing trend of rising capital expenditure from FY17 and in line with that, our capital expenditure continued to accelerate in FY22.

For Orion, much of this increase reflects strong growth in our customer numbers.

Figure 4.5.9 Comparing capex per MWh and industry performance



* Wellington Electricity, WEL Network and Unison

4.5.6.1 Operational expenditure per MWh

Figure 4.5.10 compares our performance for opex per MWh with both average industry performance and a subset comparator group.

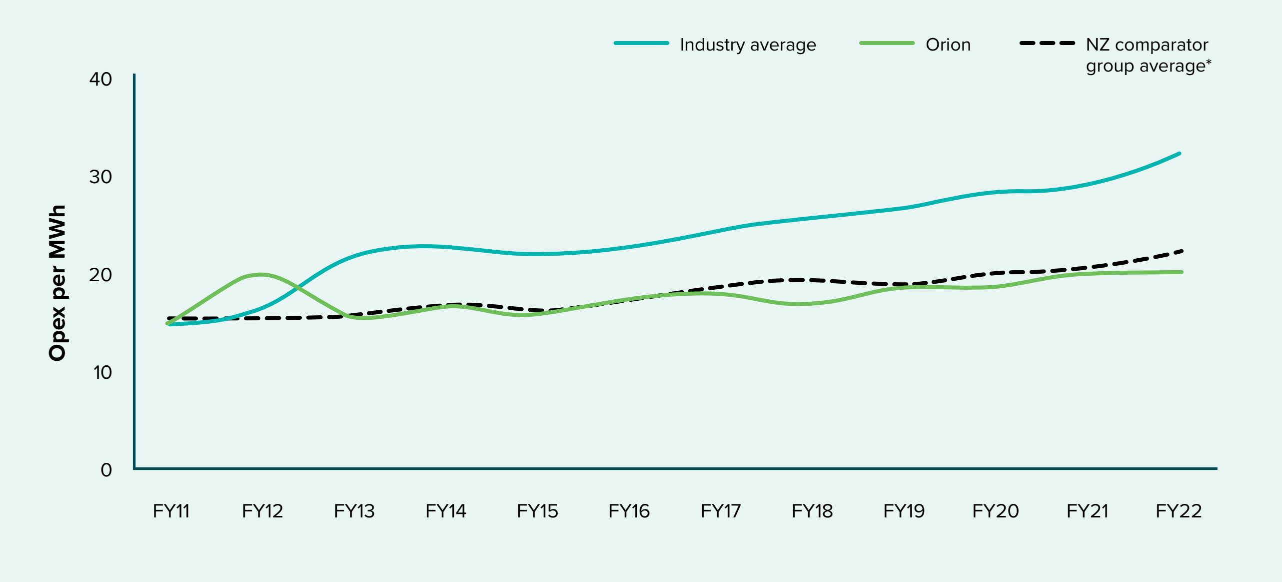
A short term increase in our opex expenditure, combined with a reduction in consumption from impacted buildings immediately following the 2010 and 2011 Canterbury earthquakes, is clearly visible between FY11 and FY13.

Despite this our operating expenditure remains substantially aligned with that of the industry average and strongly aligned with the subset NZ comparator grouping preceding FY13.

All three parameters show a gradual ramping up trend of operating expenditure from FY13. We forecast a significant increase in both capital and operational expenditure in the period of this plan. See Sections 2 and 9.

We forecast a significant increase in both capital and operational expenditure in the period of this plan.

Figure 4.5.10 Comparing opex per MWh and industry performance



* Wellington Electricity, WEL Network and Unison

4.5.6.2 Operational expenditure per ICP

Figure 4.5.10 compares our performance for opex per ICP with both average industry performance and a subset NZ comparator grouping. A short term increase in our opex expenditure, combined with a reduction in connected ICPs immediately following the 2010 and 2011 Canterbury earthquakes, is clearly visible between FY10 and FY13.

Despite this our operating expenditure follows a similar path, although at a slightly higher level due to the combination of ICP reconnection and decommissioning post-quake, with that of the subset NZ comparator grouping preceding FY13.

Overall we are proud of our performance and feedback from our customer engagement tells us we are meeting our customers' service expectations. We are focused on our Purpose to power a cleaner and brighter future with our community. The industry average follows a similar upward trend but at a notably higher average level possibly due to the inclusion of smaller EDBs with rural low density networks. All three parameters show a ramping-up trend from FY13.

Our ICPs increased from 189,000 at the end of FY13 to 213,700 at the end of FY22. Our on-going increase in opex per ICP reflects the increased operational cost of servicing these new ICPs, and remains in step with the NZ comparator group.

Overall we are proud of our performance and feedback from our customer engagement tells us we are meeting our customers' service expectations.

Figure 4.5.11 Comparing opex per ICP and industry performance

* Wellington Electricity, WEL Network and Unison

5 Our planning approach

8,000
Square kilometres network coverage

11,700
Kilometres of lines and cables

50
Zone substations

400
Major customers with loads from 0.2MVA

90,000
Orion power poles

11,900
Distribution substations

Photo: Growth in subdivisions such as this in Rolleston is a key driver of projects in this AMP.

Contents

5.1 Introduction

This section presents an overview of Orion's network, how we manage investment in our network, our network architecture, and our major customers' loads. See Section 6 for details on how we manage the lifecycle of our assets and Section 7 for how we plan the development of our network.

5.2 Our network today

5.2.1 Transpower Grid Exit Points (GXPs)

Orion's network is supplied with power from seven Transpower Grid Exit Points (GXPs), listed in Table 5.2.1. The three remote GXPs at Coleridge, Arthur's Pass and Castle Hill each have a single transformer and a relatively low throughput of energy.

The number of customers joining Orion's network is growing at around 4,000 per year, with many of these new customers being located to the west and south of Christchurch. This is increasing our reliance on the Islington GXP. To support customer growth and ensure the reliability and resilience of our network, in FY22 we commenced work with Transpower to build a new GXP at Norwood, near Dunsandel. The new Norwood GXP is expected to be commissioned by December 2023.

We have a number of assets installed at Transpower GXP sites. These assets include subtransmission and 11kV distribution lines and cables as well as communication equipment and protection systems. They are covered by an Access and Occupation Schedule Agreement with Transpower. Orion owns all the subtransmission and distribution assets connected to the GXPs.

Transpower charges electricity distributers such as Orion and direct connect customers for the cost of upgrading and maintaining GXPs. We work with Transpower to plan for GXP connection asset upgrades to ensure that any capital expenditure at the GXP is cost effective. Security of supply for our subtransmission network largely depends on how Transpower's assets are configured. We continue to review quality and security of supply gaps.

Table 5.2.1 Customers by Grid Exit Point as at 31 March 2023

GXP	Customers %
Islington	71%
Bromley	26%
Hororata	2%
Coleridge, Arthur's Pass, Castle Hill and Kimberley	1%

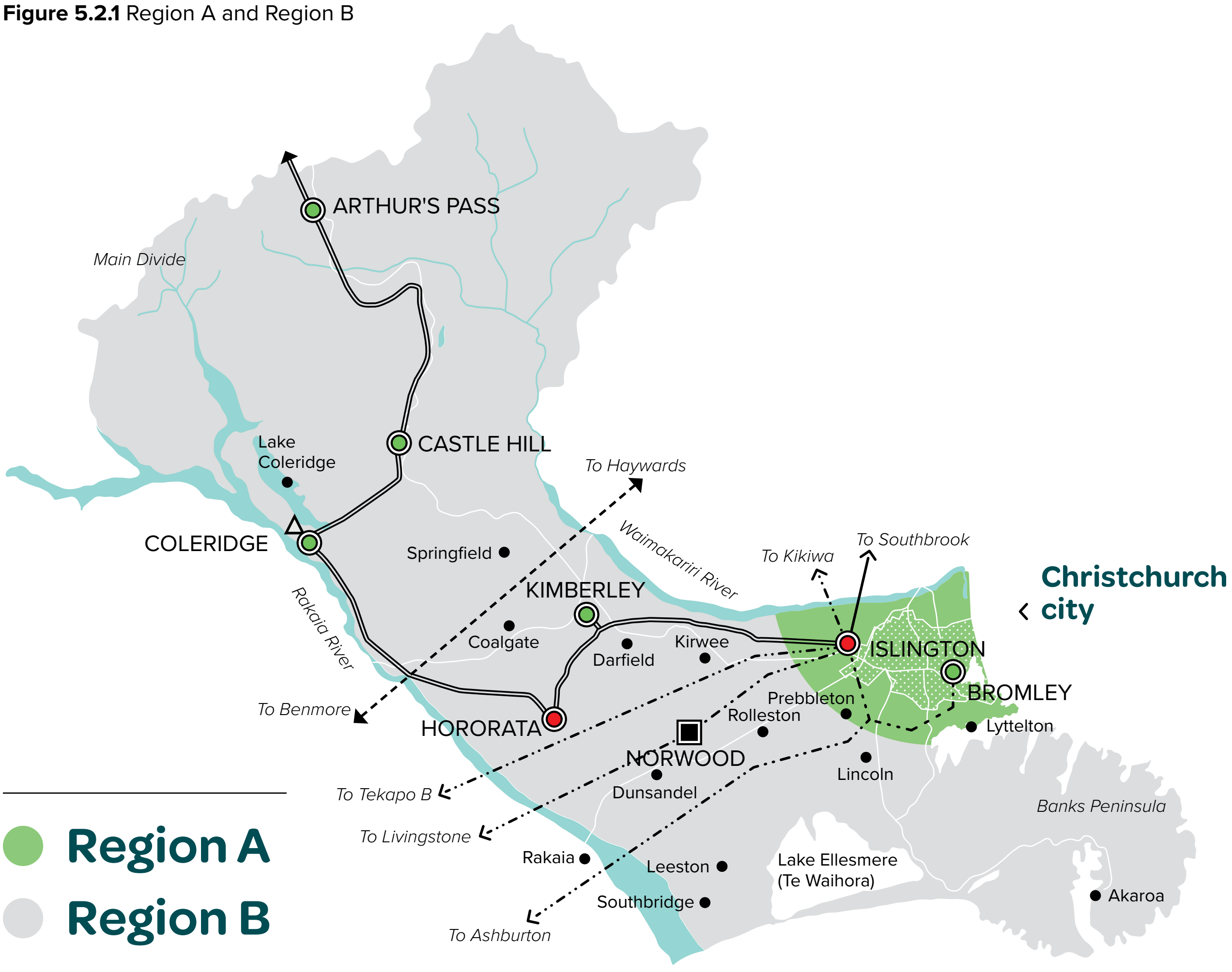
Orion's network serves a diverse range of customers, spread over a variety of terrains with different challenges. For planning purposes, our network is divided into two regions:

Region A – Christchurch city and outer suburbs, including Prebbleton, approximately 83% of our customers

Region B – Banks Peninsula, Selwyn district and townships, approximately 17% of our customers

Orion's network serves a diverse range of customers, spread over a variety of terrains with different challenges.

Figure 5.2.1 Region A and Region B



Key:

- Power station
- Transpower GXP
- Transpower GXP – commissioned December 2023
- Transpower 220kV circuit
- Transpower 66kV circuit
- High voltage direct current line

GXP maximum demand – as a percentage of firm capacity

- More than 90%
- Between 70% and 90%
- Less than 70%

5.2.1.1 Region A GXPs

As shown in Figure 5.2.1 Region A GXPs are located at Islington and Bromley and supply Christchurch Central City, Lyttelton and the wider Christchurch metropolitan area. Islington and Bromley 220kV substations form part of Transpower's South Island grid. They interconnect between the major 220kV circuits from the southern power stations and our 66kV and 33kV subtransmission network. Islington has a 66kV and 33kV grid connection, while Bromley supplies a 66kV grid connection only.

5.2.1.2 Region B GXPs

Islington GXP also supplies a large part of the Region B network including Banks Peninsula, milk processing near State Highway 1, irrigation east of State Highway 1, and the Dunsandel, Rolleston and Lincoln townships. Hororata and Kimberley GXPs supply a significant proportion of inland irrigation load and milk processing. These two GXPs have a connection to the double circuit 66kV line between Islington and the West Coast with generation injection at Coleridge power station. Transpower provides a 66kV connection at Kimberley and a 66KV and 33kV connection at Hororata. Norwood GXP, when operational, will also supply this area.

The remainder of Region B is fed at 11kV from three small GXPs at Arthur's Pass, Coleridge and Castle Hill. Together these supply less than 1% of our customers and load.

5.2.2 Network architecture

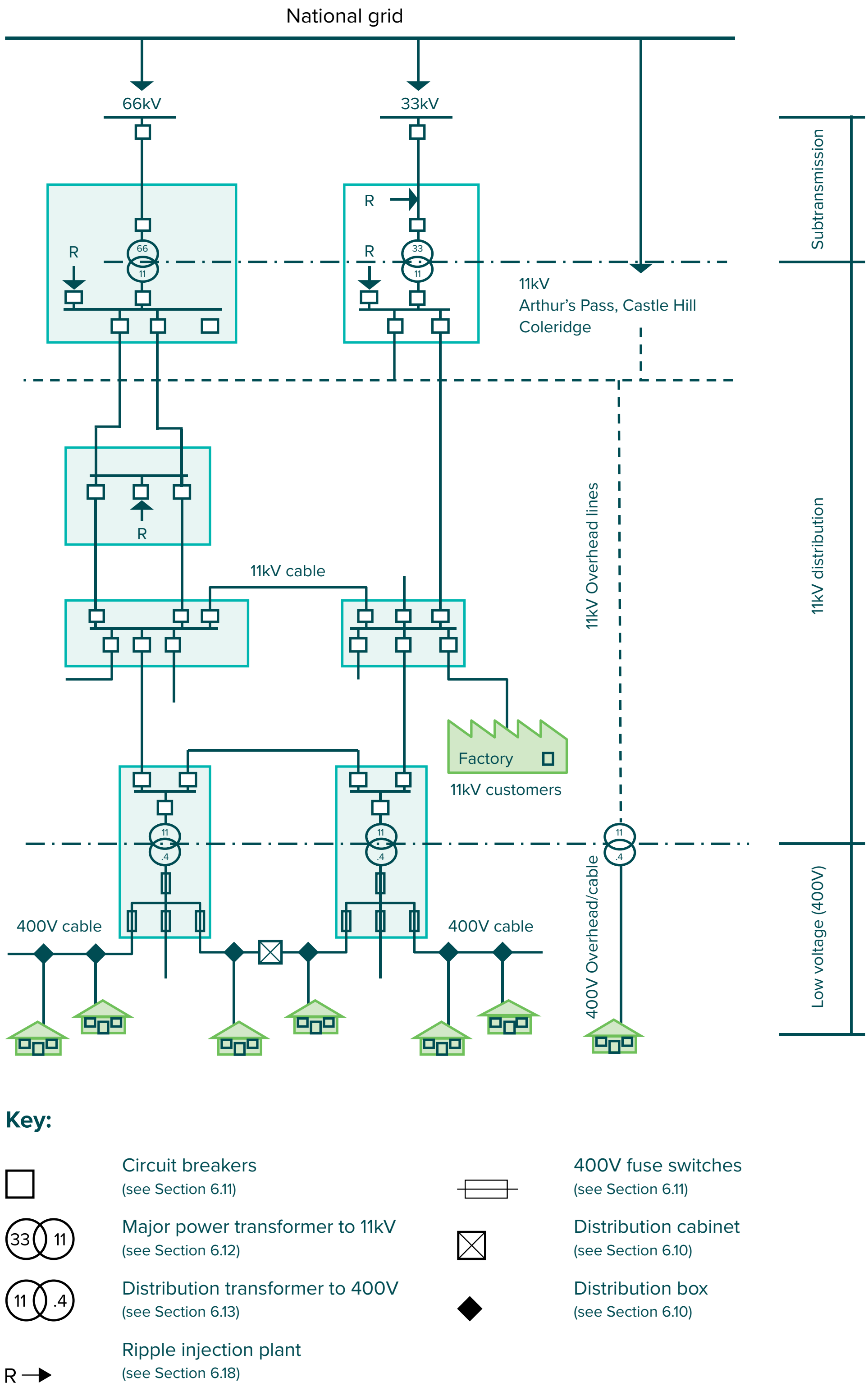
Figure 5.2.2 shows an overview of our network architecture.

Figure 5.2.2 Network voltage level and asset relationships

Transpower GXPs
See Figure 5.2.1

Orion 66kV and 33kV Zone substations
See Section 6

Orion Distribution substations
Building, kiosk and pole
See Section 6



5.2.3 Network resilience and security considerations

When planning our network, we:

- monitor utilisation against thresholds to identify constraints
- compare network capacity against load forecast scenarios to identify capacity limitations
- apply the security standard to identify security limitations
- consider options and develop projects to address constraints and limitations

5.2.3.1 HV Security of Supply Standard

Security of supply is the ability of a network to meet the demand for power in certain circumstances when electrical equipment fails or is damaged. The more secure an electricity network, the greater its ability to continue to perform or the quicker it can recover from a fault or a series of faults.

Our HV network reliability and resilience is underpinned by security of supply. This is grounded in the flexibility we have built into our network that enables Orion to reconfigure it to provide power from alternative sources when needed.

In addition to our HV Security of Supply Standard, where possible major customers are given the opportunity at the time of initial connection to discuss their individual security of supply requirements. We may also make changes to individual security of supply arrangements for existing major customers. Special arrangements are predominantly only provided to essential or high profile customers such as hospitals, Lyttelton Port Company, Christchurch International Airport and public sports venues.

See our HV Security of Supply Standard in Table 5.2.2.

Our HV Security of Supply Standard:

- provides a 'table of rules' that describes our desired level of service after different types of asset failure. The failure could be intrinsic or due to external influence, e.g. weather, or third-party damage
- defines whether an interruption may, or may not, occur following an asset failure and if so, the length of time that customers should expect to be without power
- sets the guidelines by which we build our network. It is one of the key factors behind our reliability performance

The standard does not provide exhaustive detail and has been developed as a first pass guideline for our network development team. It errs on the side of caution by providing a high level of security for customers who place a high value on the supply of electricity. If our network security does not match the level of security required by the security standard, then a gap in security is listed in Section 7.2. Before implementing a major solution to eliminate a security gap, our Network Development team ensures that the solution can be justified with economic analysis and a risk assessment.

Table 5.2.2 HV Network Security of Supply Standard

Security Standard Class	Description of area or customer type	Size of load (MW)	Single cable, line or transformer fault, N-1	Double cable, line or transformer fault, N-2	Bus or switchgear fault
Transpower GXPs					
A1	GXPs supplying CBD, commercial or special industrial customers	15-600	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
B1	GXPs supplying predominantly metropolitan areas (suburbs or townships)	15-600	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
C1	GXPs supplying rural and semi rural areas (Region B)	15-60	No interruption	Restore within 4 hours (Note 1)	No interruption for 50% and restore rest within 4 hours (Note 1)
D1	GXPs in remote areas	0-1	Restore in repair time	Restore in repair time	Restore in repair time
Orion 66kV and 33kV subtransmission network					
A2 (Note 2)	Supplying CBD, commercial or special industrial customers	15-200	No interruption	Restore within 1 hour	No interruption for 50% and restore rest within 2 hours
A3	Supplying CBD, commercial or special industrial customers	2-15	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
B2 (Note 2)	Supplying predominantly metropolitan areas (suburbs or townships)	15-200	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
B3	Supplying predominantly metropolitan areas (suburbs or townships)	1-15	Restore within 2 hours	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
C2 (Note 2)	Supplying predominantly rural and semi-rural areas (Region B)	15-200	No interruption	Restore within 4 hours (Note 1)	No interruption for 50% and restore rest within 4 hours (Note 1)
C3	Supplying predominantly rural and semi-rural areas (Region B)	4-15	Restore within 4 hours (Note 1)	Restore 50% within 4 hours and the rest in repair time (Note 1)	Restore within 4 hours (Note 1)
C4	Supplying predominantly rural and semi-rural areas (Region B)	1-4	Restore within 4 hours (Note 1)	Restore in repair time	Restore 75% within 4 hours and the rest in repair time (Note 1)
Orion 11kV network					
A4	Supplying CBD, commercial or special industrial customers	2-4	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
A5	Supplying CBD, commercial or special industrial customers	0.5-2	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours (use generator)
A6	Supplying CBD, commercial or special industrial customers	0-0.5	Use generator to restore within 4 hours	Restore in repair time	Use generator to restore within 4 hours
B4	Supplying predominantly metropolitan areas (suburbs or townships)	0.5-4	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours (use generator)
B5	Supplying predominantly metropolitan areas (suburbs or townships)	0-0.5	Use generator to restore within 4 hours	Restore in repair time	Use generator to restore within 4 hours
C5	Supplying predominantly rural and semi-rural areas (Region B)	1-4	Restore within 4 hours (Note 1)	Restore in repair time	Restore 75% within 4 hours and the rest in repair time (Note 1)
C6	Supplying predominantly rural and semi-rural areas (Region B)	0-1	Restore in repair time	Restore in repair time	Restore in repair time

Notes:

1. Assumes the use of interruptible irrigation load for periods up to 48 hours.
2. These substations require an up-to-date contingency plan and essential neighbouring assets to be in service prior to the commencement of planned outages. During these outages, loading should be limited to 75% of firm capacity of the remaining in-service assets.

5.2.3.2 Network utilisation thresholds

Historic loading data from our Distribution Management System (DMS) and forecast zone substation and subtransmission utilisation figures are used to prepare our 10 year programme of network maintenance and development. Zone substations, subtransmission and distribution feeder cables are subject to four distinct types of peak load:

- **Nominal load** – the maximum load seen on a given asset when all of the surrounding network is available for service
- **N-1 load** – the load that a given asset would be subjected to if one piece of the network was removed from service due to a fault or maintenance
- **N-2 load** – the load that a given asset would be subjected to if two pieces of the network were removed due to a fault or maintenance
- **N-bus load** – the load that a given asset would be subjected to if a single bus was removed from service due to a fault or maintenance. A bus is part of the configuration of equipment in a substation. The operational flexibility and reliability of a substation greatly depends upon the bus design

As defined in our HV Security of Supply Standard the location and quantity of load has a bearing on whether all or only some of the four peak load categories should be applied to an asset for analysis.

If the nominal peak load reaches 70% or the N-1, N-2 or N-bus load reaches 90% of the asset capacity a more detailed review of the surrounding network is instigated.

5.2.3.3 Network capacity options

When we identify a capacity or security gap on our network we consider different options as solutions. For example, a constrained 11kV feeder can be relieved by installing an additional 11kV feeder to the area. But if the zone substation supplying the area is near full capacity then it may be more cost effective to bring forward the new zone substation investment and avoid the 11kV feeder expense altogether. Where appropriate, we also consider network optimisation strategies such as flexibility to address capacity and security gaps without costly network upgrades. See Section 5.3.1.

When comparing different solutions, we use the Net Present Value (NPV) test. The NPV test is an economic tool that analyses the lifecycle cost of a projected investment or project, converting the value of future projects to present day dollars. NPV analysis generally supports the staged implementation of several smaller reinforcements. This approach also reduces the risk of over-capitalisation which may result in stranded assets.

The design of a zone substation and transformer is based mainly on the forecast load density of the area to be supplied and the level of the available sub-transmission voltage. A secondary consideration is aligning the capacity of new assets with standard equipment and designs.

Table 5.2.3 provides a summary of our standard network capacities.

Table 5.2.3 Standard network capacities

Location	Subtransmission voltage	Subtransmission capacity		Zone substation capacity	11kV feeder size (Notes 1 & 2)	11kV tie or spur (Note 1)	11kV/400V substation capacity	400V feeders (Note 1)
	kV	MVA	Description	MVA	MVA	MVA	MVA	MVA
Region A	66	40	radials (historical approach)	40	7	4	0.2-1	Up to 0.3
		40-180	interconnected network					
Region A	33	23	radials and interconnected network	23	7	4	0.2-1	Up to 0.3
Region B	66	30	radials	10-23	7	2	0.015-1	Up to 0.3
		30-70	interconnected network					
Region B	33	15-23	interconnected network	7.5-23	7	2	0.015-1	Up to 0.3

Notes:
1. Network design requires 11kV and 400V feeders to deliver extra load during contingencies and therefore normal load will be approximately 50-70% of capacity.
2. 11kV feeders in Region B are generally voltage constrained to approximately 3-4MW so the 7MW capacity only applies if a localised high load density area exists.

Developing a network based on standardised capacities provides additional benefit when considering future maintenance and repair. Transformers and switchgear are more readily interchangeable, and the range of spares required for emergencies can be minimised.

When underground cable capacities are exceeded, it is normally most effective to lay additional cables. When overhead line capacities are exceeded, an upgrade of the conductor may be feasible. However, the increased weight of a larger conductor may require that the line be rebuilt with different pole spans and stronger hardware.

In this case it may be preferable to build another line in a different location that addresses several capacity issues. In Region A the installation of a new line will require a Resource Consent under the Christchurch District Plan.

New upper network capacity is installed only once new load growth has or is certain to occur. In the short term, unexpected or accelerated load growth is met by utilising security of supply capacity or procuring flexibility services to manage load. We discuss our approach to increased capacity in our architecture and network design document.

Developing a network based on standardised capacities provides additional benefit when considering future maintenance and repair.

If major customers require extra capacity or to explore options to better manage their energy consumption, we work with them to meet their needs.

5.2.4 Major customers

Orion has approximately 400 customers who are categorised as major customers. We individually discuss their security and reliability of supply requirements in relation to our normal network performance levels at the time of connection or upgrade.

If major customers require extra capacity or wish to explore options to better manage their energy consumption, we work with them to meet their needs. This can mean a change to our network supply configuration, on-site generation options or energy saving advice.

Our delivery pricing structure for major customers gives them the ability to reduce costs by managing their load during peak network demand signal times during the period from 1 May to 31 August.

Our major customers operate across a range of industries and sectors as shown in Table 5.2.4.

Table 5.2.4 Major customers by load size

Load	Industry/Sector	Number	Notes
≤ 2MVA	All	397	Includes heavy manufacturing, hotels, water and wastewater pumping stations, prisons, retail and businesses.
> 2MVA	Food processing	5	In 2022 we worked with two major food processors, Meadow Mushrooms and Silver Fern Farms to support their move to electricity from coal to sustain their operations and reduce their carbon emissions.
	Tertiary Education	1	
	Shopping mall	2	
	Hospital	2	
	Airport/seaport	2	As part of our obligations under the Civil Defence and Emergency Management Act we have on-going discussions with life-line services such as the hospitals, seaport and airport to ensure appropriate levels of service are provided for in our future planning.
	Manufacturing	3	
	Sewerage and Drainage Services	1	

5.3 Tools for managing our network

5.3.1 Network optimisation strategies

Like roads, electricity networks have 'rush hours' where loading levels peak and capacity is heavily utilised. One solution to cope with these relatively short periods of high loading is to expand our network's capacity - much like making roads bigger to handle more traffic. However, building this additional capacity would be very expensive.

To ensure our network investments represent good value for money, Orion explores other, more cost-effective alternatives to optimise utilisation before investing in traditional reinforcement. These may be to:

- influence or control demand using flexibility, hot water load management, and smart network solutions which can benefit customers through more efficient network utilisation, or
- optimise the existing network configuration and enable the measured release of capacity through switching

5.3.1.1 Flexibility

Our customers are looking for greater flexibility and choice in meeting their energy needs and, for Orion, this creates opportunities to better manage the security of supply to our community. For example, through pricing signals we may be able to stimulate changes in the demand or generation patterns of our customers, with the effect of reducing network constraints.

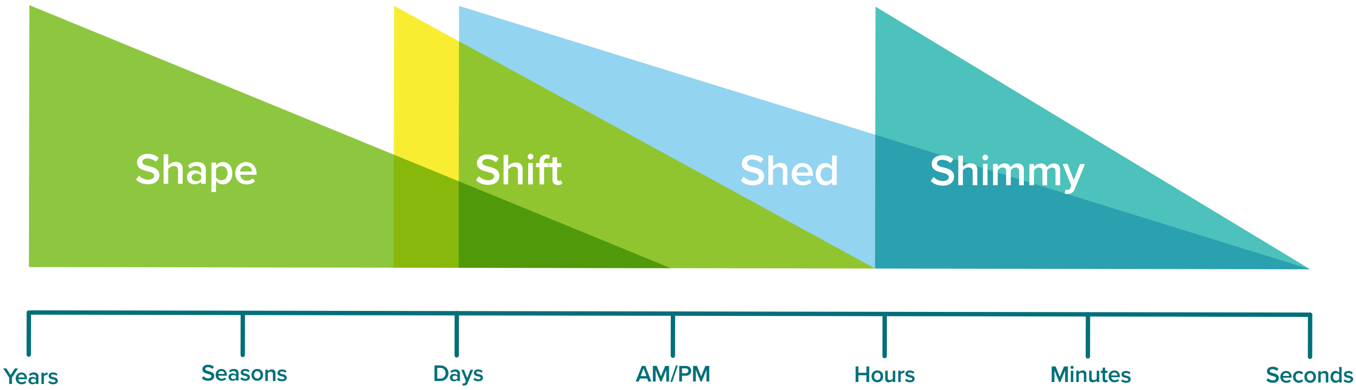
Our customers are looking for greater flexibility and choice in meeting their energy needs and, for Orion, this creates opportunities to better manage our network load.

Customers can also build flexibility into their energy management by using Distributed Energy Resources (DER), such as electric vehicles or battery storage systems. Enabling customers to connect DER to our network and creating opportunities for them to support the electricity system is a critical part of our role in powering a cleaner and brighter future with our community.

Flexibility can be stimulated by price-based mechanisms, such as distribution pricing, or agreed in advance through contractual arrangement or emerging flexibility markets which use near real-time reward mechanisms to adjust electrical energy generation and usage in line with the levels of demand.

The mechanism used to incentivise flexibility depends on the type of constraint and desired response. For the various methods of demand response referred to in the energy sector, see Figure 5.3.1. Orion has or is exploring flexibility mechanisms that cover all of these methods of demand response.

Figure 5.3.1 Methods of demand response – Source: Lawrence Berkeley National Laboratory (LBNL)



Shape – encourage energy efficiency and influence behaviour
Shift – store surplus energy and smooth peaks
Shed – reduce load to manage contingency events
Shimmy – minimise load fluctuations to maintain system stability

Using flexibility to lower costs

Except for our major customers, Orion does not charge each home or business on the network individually. Instead, we charge retailers operating in our region on a wholesale basis for the total electricity used by all of their residential and small business customers. Retailers consider Orion's delivery charges as well as other costs and then 'repackage' them into various pricing plans for their residential and small business customers.

When we review our prices each year, our goal is to set prices that encourage the efficient and cost effective use of our network for the long-term benefit of our customers. These price signals can support and reward customers for being flexible with their energy use to flatten the demand curve. For a residential customer, 'Peak' and 'Off Peak' pricing plans can enable them to save by shifting demand from hot water cylinders, electric vehicles or even delaying putting on the dishwasher. Efficient pricing is important as New Zealand continues on its journey to be Net Zero by 2050 and we engage with retailers on our pricing strategies to shape and shift load.

For major customers, Orion provides control period pricing signals that provide a financial incentive to reduce or delay power usage, and if possible switch power sources. This has the impact of reducing our overall network load in a cost-effective manner. Our service targets are to signal this between 80 to 100 hours per year and this can provide up to 25MW of response, including embedded generation.

Orion offers an Irrigation Interruptibility Scheme where we pay rebates to customers who allow us to interrupt their power supply to designated irrigators during a capacity emergency to help keep the power on for the wider community. This provides up to 15MW of response during contingencies. Although rarely used, the scheme allows Orion to reduce the load to irrigators leaving sufficient capacity remaining in the network to continue to supply electricity to more essential services, such as dairy sheds and medical centres. It also means we do not need to invest in infrastructure to maintain services in an emergency in many rural areas, keeping costs and prices down for customers.

For Orion's larger network projects, we assess the feasibility and viability of flexibility services to avoid or defer network development.

In November 2022, we issued a call for Expressions of Interest to emerging flexibility suppliers to seek cost effective, reliable alternative solutions to building additional network infrastructure in the Lincoln area. Our objective is to defer construction of a new zone substation and other upgrade works in the area, given load growth that is occurring in and around Lincoln.

Orion's ambition is to leverage our expertise and capability in load management to accelerate our development of flexibility services. We are commited to this through our involvement in the South Island Distribution Group (SIDG)

5.3 Tools for managing our network continued

roadmap development and the FlexForum, an industry group focussed on new energy solutions.

We continue to explore opportunities for flexibility with customers and third parties and seek to establish mutually beneficial partnerships in this area.

5.3.1.2. Hot water load management

Orion has a long history of managing peak loading to promote efficient operation of the network and avoid or defer costly transmission and distribution network reinforcement. Currently, the primary mechanism used to facilitate load management on our network is through ripple control relays.

Orion uses ripple control to manage load in two ways:

- **Peak hot water cylinder control** – when network loading is high, usually on the colder winter weekday mornings and evenings, Orion has the ability to temporarily turn off hot water heating to reduce peak demand. This enables customers to take advantage of cheaper retail pricing plans and contributes approximately 50MW of peak load deferment
- **Fixed time control** – Orion uses fixed time control to permanently shift load away from periods of peak demand and to also enable customers to take advantage of the lower electricity costs during nights and weekends. Fixed time control is mainly applied to larger hot water cylinders and contributes an estimated 75MW peak reduction.

In the future, ripple control technology is likely to be displaced by alternative systems such as smart appliances responding to signalling over cellular or fibre telecommunications infrastructure.

This will then allow hot water systems to be more easily controlled for purposes other than peak load management, and potentially contribute to real-time balancing of electricity supply and demand enabling increased growth of intermittent renewable generation.

This form of load management will mean that until regulations and the market are further developed, there is uncertainty on how, when and for what purpose and cost, hot water cylinders will be controlled. This means there is a risk that in the future, Orion may not be able to rely on as much hot water control at peak network times. This may result in network development at considerable cost to our community.

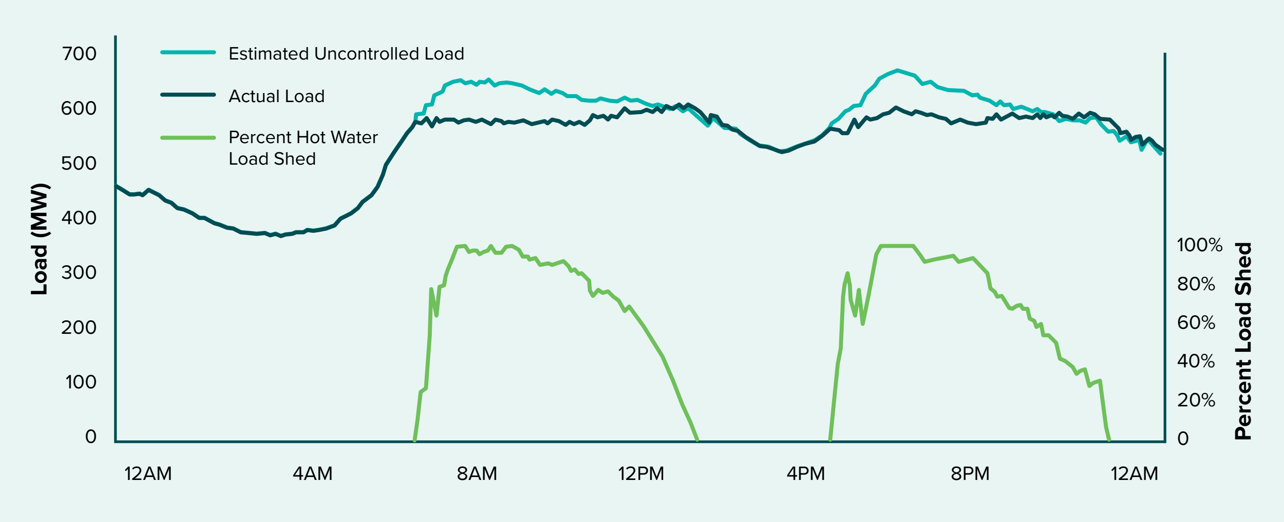
In this AMP, we assume we will need to build our network for an increase in peak load of 31MW by 2035 due to loss of hot water control from 2027.

We will continue to work with regulators, retailers, customers and meter owners to ensure that the benefits of load management are retained during any transition to other technology options.

In addition to controlling hot water in our network area we also provide a service to coordinate the management of hot-water cylinders on other distributors' networks to manage peaks on Transpower's upper South Island network. We do this via a specifically designed upper South Island load manager which communicates with Transpower and all upper South Island distribution network companies. Co-operation and the coordination of upper South Island load management enables us to reduce peaks without excessive control of hot-water cylinders.

A demonstration of the effectiveness of Orion's winter load management, via hot water cylinder control and price signalling, in reducing the overall network load is shown in Figure 5.3.2.

Figure 5.3.2 Example of a winter peak day demand profile



Note: uncontrolled load is our estimate of the loading levels that would have occurred if we had not controlled load.

5.3.1.3 Smart network solutions

In addition to flexibility and load management, we also employ other techniques to optimise network utilisation. These include:

- **Special Protection Schemes, Active Network Management** – to optimise the use of system and to provide greater levels of reliability, we often use multi-feeder parallel networks at a subtransmission or distribution level. These systems sometimes use a Special Protection Scheme (SPS) and work by actively isolating healthy networks to ensure overloads and faults do not result in wider network outages. The situations where SPSs operate are generally very low probability and SPSs are often temporary before a permanent solution is found.
- **Static and Dynamic Operating Envelopes** – in the past where temporary loads have been connected on constrained areas of our network, we have used Dynamic Operating Envelopes (DOE) driven by real-time measurements to signal pending constraints to customers to indirectly manage our zone substation load. DOEs provided a tool to enable the over-allocation of static network capacity to operate within the dynamic capability of, for example, a power transformer. We will look for future opportunities to enhance our DOE capability to enable greater use-of-system and third-party participation.

  We are also looking at ways to enable the use of Static Operating Envelopes to leverage the diversity of load with dynamic capacity allocation for major customers who have flexible capacity requirements. In the future we will also look to utilise dynamic asset ratings to enable greater utilisation of our assets.
- **Phase balancing** – on low voltage networks, circuit loading can become unbalanced over time as new customers are connected to different phases. This can often lead to a constraint on the most heavily loaded phase while other phases still have available capacity.

  Where customer loads on a circuit have a consistent usage profile, additional network capacity can be unlocked by manually reallocating customers to more lightly loaded phases. However, as customer usage patterns change, manually balanced networks can become unbalanced again. Therefore, we are also investigating methods of active phase balancing which can automatically adapt to these changes and optimise network utilisation. This will enable the managed release of latent capacity in our network.
- **Power factor correction rebate** – if a customer's load has a poor power factor then our network and the transmission grid are required to deliver a higher peak load than is necessary. This may lead to the need for an upgrade. Our Network Code requires all customer connections to maintain a power factor of at least 0.95. In the Christchurch urban area the predominately underground network is high in capacitance which helps to improve power factor, and the minimum 0.95 power factor requirement has resulted in an overall 0.99 GXP power factor at times of network peak. This is a good outcome and any further benefit from offering financial assistance to correct power factor in the urban area would be uneconomic.

  However, in the rural area, the predominately overhead network is high in inductance which reduces power factor and we offer a financial incentive in the form of a 'power factor correction rebate' to irrigation customers with pumping loads greater than 20kW. The rebate provides an incentive for irrigators to correct their power factor to at least 0.95.

  The rebate is set at a level where it is economic for the customer to provide power factor correction, which is lower than the avoided network investment cost associated with power factor related network upgrades.

Given Orion's LV networks supply more than 99% of our customers, developing the visibility and capability of these networks is essential to efficiently manage our networks and facilitate customer choice.

5.3.2 Network visibility

Orion has good visibility and control of our HV network through use of SCADA-enabled field devices at most circuit breakers and zone substations. This data is used to assess asset utilisation and performance to inform our network investment.

However, this is not the case with our LV network which were planned for reasonably stable passive household loads with one-way power flow. As more customers adopt technologies such as EVs, and as more multi-unit housing intensification occurs, these street-level LV systems may experience increasing levels of constraint.

Given Orion's LV network supplies more than 99% of our customers, developing its visibility and capability is essential to efficient management of our network and facilitating customer choice.

We have two LV initiatives to increase LV network visibility:

- LV monitoring
- smart meter information gathering

These initiatives will help us to:

- provide information to guide our operational, planning and investment activities
- develop improved forecasting and modelling techniques
- facilitate customer choice by better enabling customers to charge batteries during off-peak times and potentially export power into our network at peak times – thereby lowering their net cost of electricity
- improve customer service through increased real-time identification and location of faults
- identify poor performing feeders and quality of service to individual customers, which will then allow us to target actions to improve customer experience
- reduce capital and operational costs by early warning of power quality problems, such as phase imbalance
- enhance safety as real- or near-time monitoring provides measurements which will better inform us of what is live, de-energised, and outside of regulatory limits
- display constraints in our network online, enabling others to participate in developing solutions

5.3.2.1 LV monitoring

LV monitoring enables us to observe the use of power in near real time, at street level. This low voltage monitoring samples power flows and voltage at 10 minute intervals, generating a wealth of data that will allow us to see and respond to changes of activity on the network. Having visibility of how our network is being used at this granular level will also help us to provide customers with a more flexible, dynamic range of choices for managing their energy needs.

In FY20, we began a 10 year programme to install LV transformer and feeder monitoring at selected sites. We revised this programme in FY21 to target a smaller group of high-risk sites with an accelerated completion in FY26 based on constraint modelling conducted in partnership with the Electric Power Engineering Centre (EPECentre) at the University of Canterbury. In FY22, we installed 202 LV monitors, with our total fleet now covering approximately 26,000 customer connections.

Analysing the data from these monitors is enabling us to develop a better understanding of baseline LV demand and will enable us to see how it changes as adoption of EVs, solar PV, battery storage and energy sharing become more prevalent, and patterns in customer behaviour emerge.

In the long-term, we aim to use this data to monitor trends and demand profiles at the LV feeder level to inform our investment decisions. We are already beginning to use this data to initiate network upgrades in certain areas.

We can also leverage our LV monitoring programme to gain greater visibility of our HV network by using the live LV monitor data in conjunction with the state-estimation capabilities of our Advanced Distribution Management System (ADMS).

With increasing rates of installation, we expect to achieve our target of 1,600 sites by the end of the programme in FY26. See Section 7 for details of this programme.

5.3.2.2 Smart meter information gathering

While the LV monitoring programme will provide us with excellent information on our network's performance at the start of a feeder, information from further downstream is required to fully assess the performance of our LV network.

LV monitoring enables us to observe the use of power in near real time, at street level.

The quality of electricity supply varies depending on where a home is located along the length of a feeder, for example, the last few houses on a line may be more susceptible to voltage performance issues.

To monitor performance of this aspect of our service, we'll require information from one of two sources:

- LV monitors installed further down the feeder on our side of the customer's point of supply, for example on the last power pole or in the distribution box, or
- existing smart meters installed on the meter board at the customer's home

Our preference is to use smart meters already installed on homes as this is likely to be the most cost-effective and efficient option for our customers, compared to Orion installing new standalone monitors.

We are negotiating an agreement with a key meter provider to access smart meter information. This meter provider manages 95% of the meters on our customers' premises. This data will help us prioritise where we should install real-time monitoring. An allowance for procuring this additional smart meter information has been incorporated in our operational expenditure.

5.4 Network investment framework

5.4.1 Project prioritisation

Prioritisation of network capex projects is a complex process that involves considering multiple factors that are both external and internal to Orion.

Key considerations are managing risk, capitalising on opportunity and executing the company strategy. When scheduling our projects, factors we take into account are listed in Figure 5.4.1.

Figure 5.4.1 Factors we consider when prioritising our projects

Customer expectations	We give priority to addressing complaints most likely to impact customer supply through extended or frequent outages, or compromised power quality.
Waka Kotahi and local authority projects	We aim to schedule our projects to coincide with the timing of key infrastructure projects where locations overlap. This may cause us to bring forward or delay capital works projects to avoid major future complications and unnecessary expenditure. The most common activity of this type is coordination of planned cable works with any future road-widening or resealing programmes to avoid the need to re-lay or excavate and then reinstate newly laid road seal.
Service provider resource	We aim to maintain a steady worklflow to service providers and ensure project diversity within a given year. This ensures service provider skills, competence and equipment levels match our capital build programme year-on-year at a consistent level, reducing the risk of our service providers being over or under resourced.
Transpower projects	We endeavor to coordinate any major network structural changes adjacent to GXP with Transpower's planned asset replacement programmes, and provide direction to Transpower to ensure consistency with our subtransmission upgrade plans.
Internal projects	Where practical, we attempt to align scheduling for our network development, asset replacement and asset maintenance works where sites overlap, for example co-ordinating zone substation transformer refurbishment and circuit breaker replacements with reconfiguration networks.
Timing	The final decision to undertake investment in projects for the coming year depends on urgency. Seasonal timing to avoid taking equipment out of service during peak loading periods also applies, and we undertake projects in metropolitan areas in summer and projects in farming areas in winter where possible.

Projects not selected for next year are provisionally assigned to a future year in the 10 year planning window. When next year's project selection process is undertaken all projects are reviewed and, depending on changes in information and priorities, either maintained in the planning schedule, advanced, deferred, modified, or removed. Our objective is to smooth the works programme by deferring where we can or bringing projects forward where appropriate. For more information on deliverability see Section 10.

5.4.1.1 New project prioritisation tool

To bring more rigour to our project prioritisation process, we are developing a tool to help balance the competing priorities for capex investment in our network. The purpose of the project investment prioritisation tool is to help us develop a portfolio of capital projects most aligned with the Orion Group strategy and which meet our asset management objectives. The tool values each project using value drivers to create a value score. This is then used to rank projects by the ratio of value produced per unit cost to create a prioritised list of projects.

Value is defined by more than traditional quantified outcomes such as SAIDI and SAIFI. The value framework includes a wide range of value measures intended to broadly represent all significant sources of value creation that investments bring.

The tool will also capture high level risks and resource requirements for projects and show alignment with the Orion Group strategy and Orion's asset management objectives, see Section 2.13.

5.4.2 Business case development

Once a project/programme scope has been defined in the development stage and prioritised, we document our thought process in business cases and/or Asset Management Reports (AMRs) for leadership team review and in some cases board approval. Business cases support our network development and complex lifecycle management capital projects, and AMRs support our lifecycle management portfolio programmes of work. Business cases are often underpinned by an overarching strategic business case which addresses our security of supply architecture standards.

Orion uses an asset planning decision framework to decide the complexity of a business case based on the network project type proposed, see Table 5.4.1.

Table 5.4.1 Asset planning decision framework

	Level 1	Level 2	Level 3
Project type	Renewal, replacement, AMR	Minor project, renewal, replacement	Security of supply, architecture (reticulation or protection), major project, renewal, replacement
Principal criteria	Single solution	Risk based	Cost benefit analysis of multiple options
Primary driver	Need for routine maintenance / inspection, like for like renewal	Safety, regulatory compliance, obsolescence, renewal / reinforcement	Weighing up options to improve reliability, resilience, future network, renewal / new build, overhead to underground conversion
Customer impact and engagement	Assessing customer impact, talking with customers i.e., from ongoing outage event analysis, customer enquiries, complaints, surveys, workshops, focus groups and Customer Advisory Panel		Specific project engagement and / or consultation

5.4.3 Network investment process

When a network issue is identified, for example a safety risk, capacity or security of supply gap, we start the project development process. During this process, we work through three distinct stages to develop the project scope.

These project scope stages are:

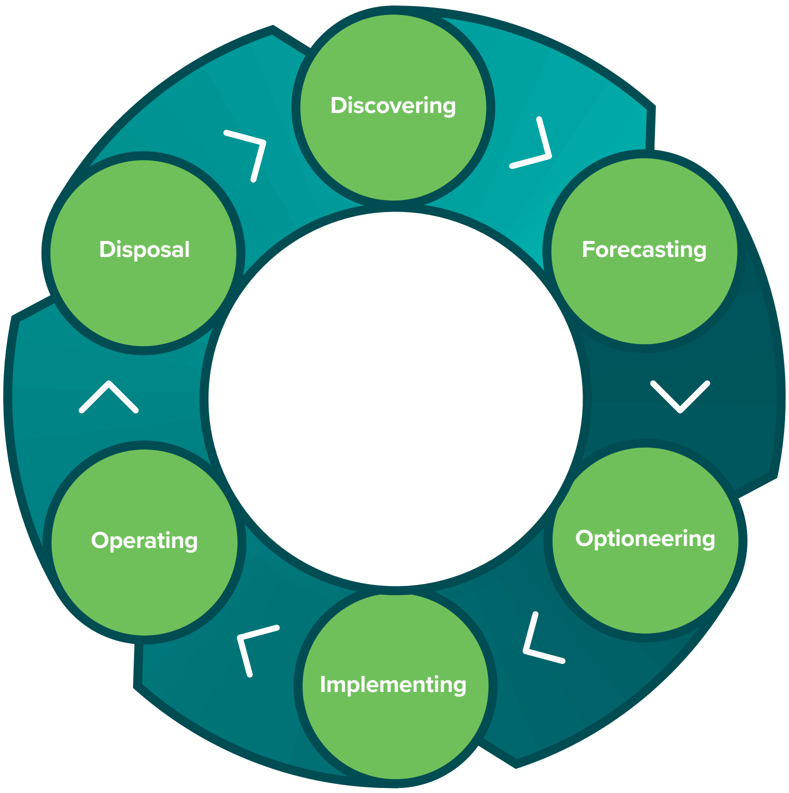
- **Discovering** – developing an understanding of project drivers and customer needs
- **Forecasting** – forecasting future asset related risks and device appropriate asset management strategy
- **Optioneering** – evaluating options to address constraints, including innovative solutions and business case development

Once a new project has been scoped we implement the preferred solution then enter the lifecycle phase of operating, monitoring and maintaining:

- **Implementing** – planning and delivering strategic investments in network and non-network solutions
- **Operating** – day-to-day operation and monitoring of performance
- **Disposing** – assets need to be disposed/replaced when they reach the end of their useful lives and the cycle begins again

See Figure 5.4.1.

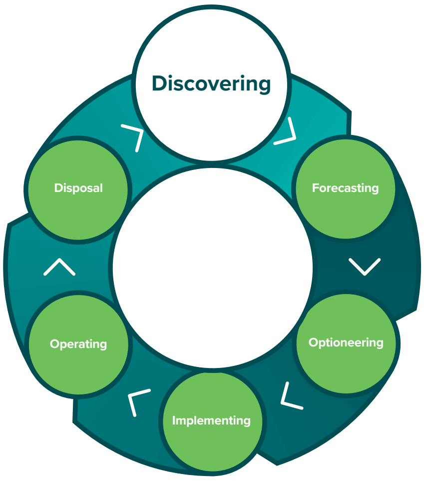
Figure 5.4.2 Six stages of the asset management cycle



5.5. Asset lifecycle management approach

Our customers tell us they want Orion to maintain a safe, reliable, and resilient network, one that is prepared for the future. We deliver this by managing the maintenance and renewal of our existing assets using an asset lifecycle management approach. Asset lifecycle management means taking a long-term view to make informed and sound investment decisions to deliver our service levels at an appropriate cost.

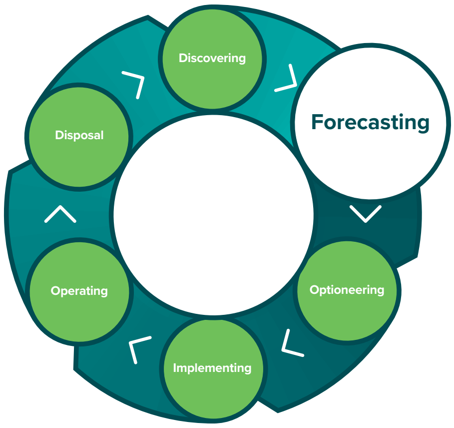
5.5.1 Discovering



The first step in the asset lifecycle management process is to establish customer needs and future network demands. We do this through customer engagement and customer satisfaction research. We also take into account health and safety considerations and regulatory requirements.

With an understanding of what's needed, we set service level targets against which we measure our performance. For details of how our service levels are set, our service level targets and our performance against them, see Section 4.

5.5.2 Forecasting



We know an asset in poor condition underperforms and has a higher risk of failure. For that reason, we forecast the projected asset health condition or asset related risk in ten years' time. We also devise appropriate asset management strategies to maintain or reduce the risk levels to allow Orion to meet our service levels targets.

5.5.2.1 Condition based risk management

We have Condition Based Risk Management (CBRM) models for our critical network assets. CBRM modelling is one of the tools we use to inform our decision making and assists us to build our asset renewal programmes. These models provide a proven and industry accepted means of evaluating the optimum balance between maintaining existing asset performance and the need for future renewals investment. These models help inform us of the health and criticality of our assets and target asset renewal.

5.5.2.2 Asset health

In CBRM, asset health is calculated based on various factors such as asset age, its installed environment, asset failure rates, engineering knowledge and inspection & maintenance data. For publication in the AMP we have aligned CBRM health indices of 0 – 10 into Commerce Commission Health categories H1 to H5 as seen in Figure 5.5.1. We use the H1 – H5 categories in Section 6 and Schedule 12a to help describe the health of our asset fleets.

Figure 5.5.1 Condition Based Risk Management score conversion table

CBRM Health Index	AMP and Schedule 12a grade	AMP and Schedule 12a definition
10+	H1	Replacement recommended
(9-10)		
(8-9)	H2	End of life drivers for replacement present, high asset related risk
(7-8)		
(6-7)	H3	End of life drivers for replacement present, increasing asset related risk
(5-6)		
(4-5)		
(3-4)	H4	Asset serviceable. No drivers for replacement, normal in-service deterioration
(2-3)		
(1-2)	H5	As new condition. No drivers for replacement
(0-1)		

5.5.2.3 Asset criticality

CBRM asset criticality evaluates what the consequence of asset failure would be based on the likely impact to safety of our people and the public, financial loss to customers through loss of supply, the cost of repair work and environmental harm caused by asset failure.

5.5.2.4 Asset risk

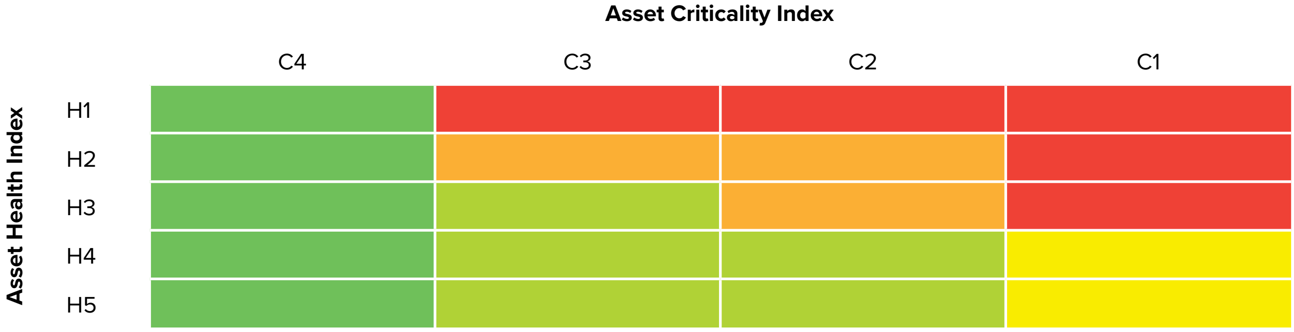
Traditionally our CBRM models quantify risk in a dollar amount, based on the probability of failure (related to the health) multiplied by the consequence of failure. We have found this dollar format lacks some context, so for some models such as for poles, we have developed a risk matrix to help further describe visually the relationship between health, criticality and risk, and the linkage to our asset management strategy as shown in Table 5.5.1 and Figure 5.5.2.

To derive the risk matrix, criticality bands are established from the consequence of failure value, ranging between C1 to C4 where C1 represents the most serious consequence. The risk grade definitions for R1 to R5 are aligned to the EEA Asset Criticality Guide and our corporate risk guideline. See Section 6.6.5 for the application of the risk matrix for poles.

Table 5.5.1 Our risk ratings

Risk ratings	Definition	Strategy
Extreme	Combination of high consequences of failure and reduced HI indicates high risk	Immediate intervention
Very high	Combination of criticality and health indicates elevated risk	Schedule intervention
High	Healthy but highly critical assets	Reduce consequence of failure
Medium	Typical asset in useful life phrase	Monitor and maintain
Low	Low relative consequence of failure	Tolerate increased failure rate

Figure 5.5.2 CBRM risk matrix



5.5.2.5 Asset renewal strategy

We use a number of techniques to ensure our assets are kept in service until their continued maintenance is uneconomic or until they have the potential to pose a health and safety, environmental or reliability risk. This is in accordance with our asset management objective to identify and manage risk in a cost-effective manner and apply a balanced risk versus cost approach to making asset maintenance and renewal decisions. Our renewal strategies are:

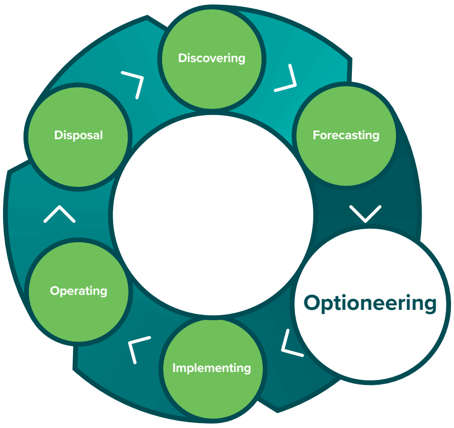
- **Condition and/or risk based** – uses data on the asset, its condition and operating context to model condition related risk and predict renewal needs. This predominately is used on high value assets with a high consequence of failure. This also includes type issues where certain types are scheduled for renewal due to safety or performance issues related to design, quality, or materials
- **Age based** – applies to assets where there is a well defined relationship between time in service and performance, e.g., batteries
- **Run to non-operational** – this strategy is adequate for a portion of some asset classes where the cost of aggressive proactive renewal or maintenance to prevent failure is disproportionate to the consequence of asset failure, e.g., some distribution transformers and non-critical monitoring equipment

5.5 Asset lifecycle management approach continued

Table 5.5.2 Asset management approach for asset class

Asset class (arranged in order of FY23 capex high to low)	Tool	Predominant condition based replacement		Predominant age based replacement	Run to non-operational	Indefinite maintenance and repair
	Approach	CBRM model	Asset condition & performance	Asset data	–	Asset data
HV Switchgear & circuit breaker		✓				
Overhead lines – 11kV		✓				
Distribution transformer					✓	
Power transformer & regulator		✓				
Protection		✓				
Overhead lines – 400V		✓				
Overhead lines – 33/66kV		✓				
Underground cables – 400V			✓			
Communication systems				✓		
Control systems				✓		
Substations						✓
Load management				✓		
Monitoring					✓	
Underground cables – Comms					✓	
Underground cables – 11kV			✓			
Underground cables – 66kV			✓			
Underground cables – 33kV			✓			

5.5.3 Optioneering

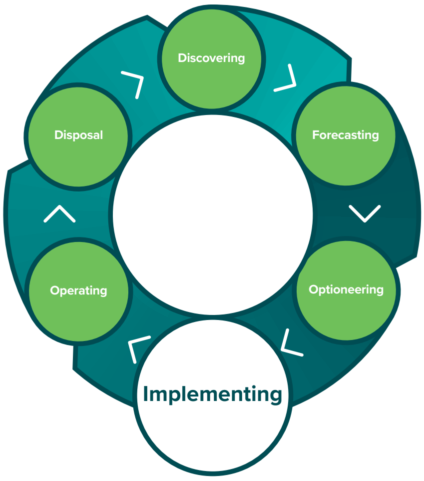


One of the main options that we analyse for our asset renewal programme is around the timing of the renewal. This ensures that customers are getting the best usage and value of our existing assets. The CBRM model can aid us in this process by creating scenarios that model the deterioration of asset condition and projected risk. This information allows us to then decide which scenario is acceptable based on its effect to our service levels.

Another option that factors into our decision making is whether an asset should be replaced like-for-like. Internal review within various working groups, analysis and planning are undertaken for the asset, its interaction with other equipment and its integration into the immediate network based on the following considerations:

- the required functions, and whether the equipment needs to be replaced or can the function be accommodated elsewhere
- manufacturer, standardisation of equipment, failure modes, industry experience with certain models, support from manufacturer
- safety
- whether the timing be linked to other work on the substation, network, or circuit to minimise outages and better utilise resources
- suitability for future change in the network
- lifecycle cost and environmental impact

5.5.4 Implementing



We utilise the project prioritisation process to determine if the work plan can be delivered.

We use service providers for the design, build and maintenance programmes identified in the AMP. To guide them, we have key standards and specifications which are set out below.

5.5.4.1. Safety in Design

The Safety in Design standard is used by Orion and our service providers to identify hazards that could exist throughout the complete lifecycle of assets from concept to disposal. The standard includes a hazard identification and risk assessment process which proposes elimination and control measures to be incorporated in the design for each identified hazard.

5.5.4.2. Design standards

To manage the health and safety, cost, efficiency and quality aspects of our network we standardise network design and work practices where possible. To achieve this standardisation we have developed design standards and drawings that are available to our service providers. Normally we only accept designs that conform to these standards, however this does not limit innovation. Design proposals that differ from the standard are considered if they offer significant economic, environmental, and operational advantages. Design standards are listed in Appendix D against the asset group they relate to.

5.5.4.3. Technical specifications

We provide technical specifications to authorised service providers who work on the construction and maintenance of our network and these refer to the relevant codes of practice and industry standards. Specifications are listed in Appendix D against the asset group they relate to.

5.5.4.4. Equipment specifications

We standardise equipment used to construct components of our network where possible. To support this, we have developed specifications that detail accepted performance criteria for significant equipment in our network. New equipment must conform to these specifications. However, without limiting innovation, equipment that differs from specification is considered if it offers significant economic, environmental, and operational advantages.

New equipment types are reviewed to carefully establish any benefits they may provide. Introduction is carried out to a plan to ensure that the equipment meets our technical requirements and provides cost benefits. It must be able to be maintained and operated to provide safe, cost-effective utilisation to support our supply security requirements.

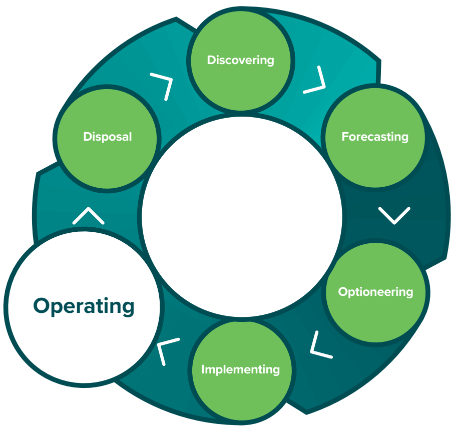
5.5.4.5. Equipment operating instructions

To ensure the wide variety of equipment on our network is operated safely and with minimum impact on our customers, we have developed operating instructions that cover each different equipment type on our network. This means that we create a new operating instruction each time any new equipment type is introduced.

5.5.4.6. Operating standards

To ensure our network is operated safely we have developed standards that cover such topics as the release of network equipment, commissioning procedures, system restoration, worker training and access permit control.

5.5.5 Operating



The operating phase of the lifecycle is in accordance with our maintenance plan. Each asset class is subject to a specific regime for routine inspection and maintenance and also specified asset replacement programmes.

Requirements and scopes of work are developed from these plans in-house and we then use our contract delivery framework to contract out works, see Section 10. Monitoring of assets is against the service levels defined in this AMP, but also against specific requirements of the asset class.

5.5.5.1 Asset maintenance strategy

At Orion, we follow a Reliability-Centred Maintenance (RCM) philosophy that ensures our assets operate in an efficient, cost-effective, reliable, and safe manner. RCM recognises that not all assets are of equal importance, from both safety and network criticality standpoints. This decision-making framework seeks to best match equipment needs with available resources for cost-effective reliability.

The detailed asset management activity of each asset class and the equipment within the asset class are described in Section 6 and in our associated internal Asset Management Reports. We have specific maintenance processes for each of our asset classes and all works generally fall into three categories:

Scheduled maintenance

- **Timed based** – majority of our assets are subjected to a routine time-based programme of inspections, maintenance, and testing. The drivers for time-based maintenance are influenced by regulatory compliance, manufacturer specifications, industry best practice and our engineering knowledge and experience
- **RCM and risk based** – we monitor the condition and performance of our assets through inspections, maintenance, and asset failures. When undesirable performance or high-risk events are identified, we investigate and determine if and what steps are required to bring improve the performance and risk of the asset fleet. This can lead to specific planned and targeted maintenance programmes or if appropriate feed into our renewal programmes

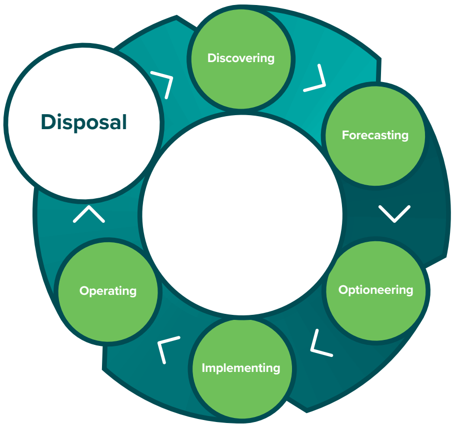
Non-scheduled maintenance

- work that must be performed outside the predetermined schedule but does not constitute emergency work
- investigative inspections and maintenance that can help determine if a scheduled program of work is needed
- follow up remedial work required after emergency maintenance

Emergency maintenance

- initial response to unplanned events that impair normal network operation including a loss of supply event
- work that must be carried out on a portion of the network that requires immediate repair due to the discovery of an immediate high risk to network supply or public safety

5.5.6 Disposing



Disposal of assets is also informed by our Asset Management Reports for each asset class and in accordance with replacement and disposal plans. As with maintenance, requirements and scopes of work are developed in-house and then go through a competitive tender process to contract out the works.

We are committed to being environmentally responsible and we dispose of our assets in an environmentally and sustainable manner that complies with legislation and local authority requirements, and minimises waste. Our service providers are responsible for the disposal of redundant assets, equipment, hazardous substances and spill wastage, including assets that fail in service, unless we specify otherwise in our contract documentation. Our service providers notify us of disposals and we update our asset information systems to record these.

We closely collaborate with our service providers to ensure that the assets are disposed of safely and that hazardous materials are not passed on to any other party without our explicit approval. When we design new assets, our Safety in Design process mandates the identification, risk assessment and control of hazards that could arise during the lifecycle of our assets, inclusive of when we dispose of them. The procedures for the disposal of redundant assets are described in Section 6 under disposal plan.

5.6. Managing growth and change

Our network is facing significant change from increasing electricity demand due to decarbonisation and new ways of managing energy. This presents both challenges and opportunities to Orion in how we manage our network.

One impact of the energy sector's transition is that Orion's historical approach to forecasting is no longer appropriate. Where previously projections of historical trends could form a reliable picture of the future, we now need to forecast emerging and uncertain trends and markets. This leads us to a greater use of scenario modelling.

This section details how we are forecasting currently and how we are improving our forecasting techniques. The improvements we are making are driven by both the greater uncertainty we have around customers' behaviour and how new technology will be used by them, and the greater network visibility we will have particularly at low voltage level.

The network development projects listed in this 10 year AMP ensure we can maintain capacity, quality and security of supply to support the forecast growth rates. Actual growth rates are monitored on an annual basis and any change will be reflected in next year's development plan.

We take a four-step approach to making decisions on investments in our infrastructure to deliver customer benefits over our AMP planning period. Each of these steps is discussed below.

5.6.1 Discovering

During the discovery phase, we uncover and analyse the drivers of growth and change, and the range of uncertainties of each.

This section sets out how we consider these drivers and include them in our forecasting process.

5.6.1.1. Growth drivers

Orion's network feeds both high density Christchurch city loads and diverse rural loads on the Canterbury Plains and Banks Peninsula.

Growth in electricity consumption in Christchurch and on Banks Peninsula historically matched growth in population. Peak electricity consumption growth on the Canterbury Plains was driven by changes in land use rather than population growth.

Changes in technology and customer behaviour, the drive to decarbonise, and recent government rule changes regarding housing intensification, mean forecasting growth in peak network demand, and where the growth will occur, has more facets to it. As most of these facets carry uncertainties, accurate forecasting of peak future demand is more difficult. This is leading the industry towards more sophisticated scenario planning, where we attempt to predict the many possible paths for demand growth and make asset investment decisions based on least regret actions.

Here we summarise the main drivers of future demand growth and set out how we include them as inputs to our demand forecasting process.

Population increases

Stats NZ provides national level population forecasts. When the national forecast is broken down to a regional level, the accuracy is less reliable. At a regional level, we derive our load forecast from a combination of bottom-up inputs, such as household growth forecasts by Christchurch City Council and Selwyn District Council.

Historical population growth forecasts have underestimated actual growth particularly in the Rolleston and Lincoln area.

Detailed data analysis of our customer connections undertaken in FY23 has identified that for the past four years Orion's customer connections have grown by around 5,000 per year, and this level of growth is forecast to be sustained within this AMP.

Adding to uncertainty around the amount and location of population growth in our region is the possible impact of recent housing intensification rules. In December 2021 the Resource Management Amendment Act was passed into law. The impact of this law if applied to Christchurch would be that we would likely see an increased rate of infill housing and subdivision. This could significantly affect our network as instead of a low voltage feeder supplying 20 standalone homes, a number could be replaced by multiple apartment units, increasing electrical load and triggering network reinforcement.

The cost to upgrade infrastructure to service infill housing in older established areas is typically greater on a per-house basis than the cost to connect a new standalone house in a new subdivision.

Customer actions

How customers respond to national concerns about peak electricity usage and respond to calls for more efficient energy consumption is unknown. Also, government rules may change given carbon neutral targets. A focus on decarbonisation could lead to improved house insulation, greater appliance efficiency, and customers responding to reduce peak load. We have assumed up to 0.5% peak reduction in some of the range of forecasts.

For the past four years Orion's customer connections have grown by around 4,000 per year, and this level of growth is forecast to be sustained.

Electric vehicles

Three of the key factors influencing the impact of electric vehicles on our network are:

- **The speed of adoption of electric vehicles** – the speed with which EVs will appear in our region over the next 30 years is very uncertain. The two biggest influences on the rate of uptake are likely to be the cost of EVs and government policy – both of which Orion does not have control over. We use various EV uptake rate scenarios modelled by government departments in our forecasting.

  To date, the number of EVs on our roads has increased steadily. See Figure 5.6.1.

  Before the number of EVs becomes substantial, clustering of EVs due to neighbourhood demographics may impact areas of Orion's low voltage network. Data from vehicle registrations indicates the suburbs with a relatively higher concentration of EVs currently are Cashmere and Halswell.
- **Charging location** – we anticipate around 85% to 90% of EV charging will occur at home in our network area, and the vast majority of this will be off-street charging.
- **Charging time** – when drivers will charge their EVs at home is a critical factor in estimating the impact of EVs on our network. Electricity networks worldwide are anticipating a significant portion of EVs will charge up in the early evening when drivers get home from work. We have a different perspective, based on the latest information coming through from international and New Zealand sources.

  Through clever pricing, education, and flexibility offerings we believe we can encourage most EV drivers to charge up overnight. This will significantly reduce the effect of EVs on our network peak demand but care will be needed to avoid creating new peaks on the low voltage network.

5.6. Managing growth and change continued

A further factor that may significantly affect the impact of EVs on networks, and the balancing of supply and demand of electricity given an increasing intermittent generation mix, is Vehicle-to-Grid (V2G) technology.

V2G technology is still emergent and expensive. Considerable uncertainty still exists on how popular it will become. For this AMP we have not included V2G technology in our baseline scenarios and expenditure forecasts.

Solar PV

Solar PV uptake in terms of connections and capacity has climbed steadily from 2008, see Figure 5.6.2. Currently only around 2% of homes and businesses in our network have solar installed, and these contribute less than 1% of the total energy delivered into our network.

Figure 5.6.1 Electric vehicle uptake in New Zealand and Canterbury

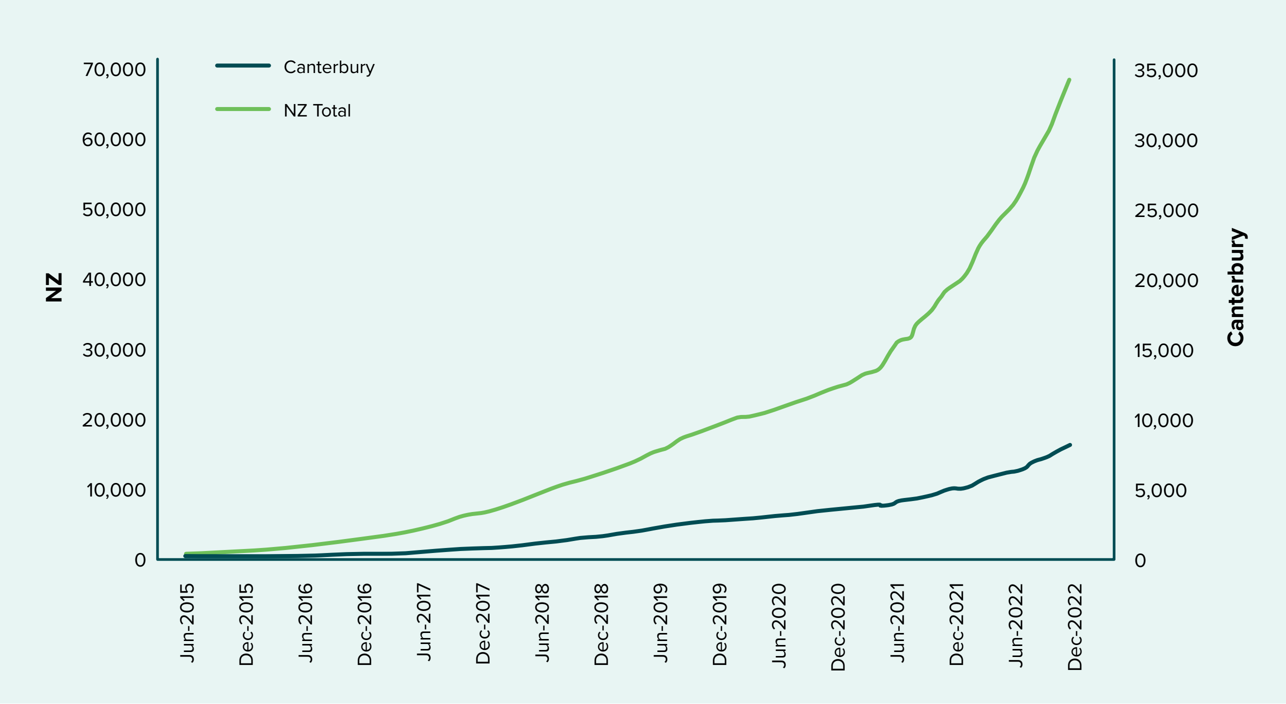


Figure 5.6.2 Current level of solar PV uptake on our network

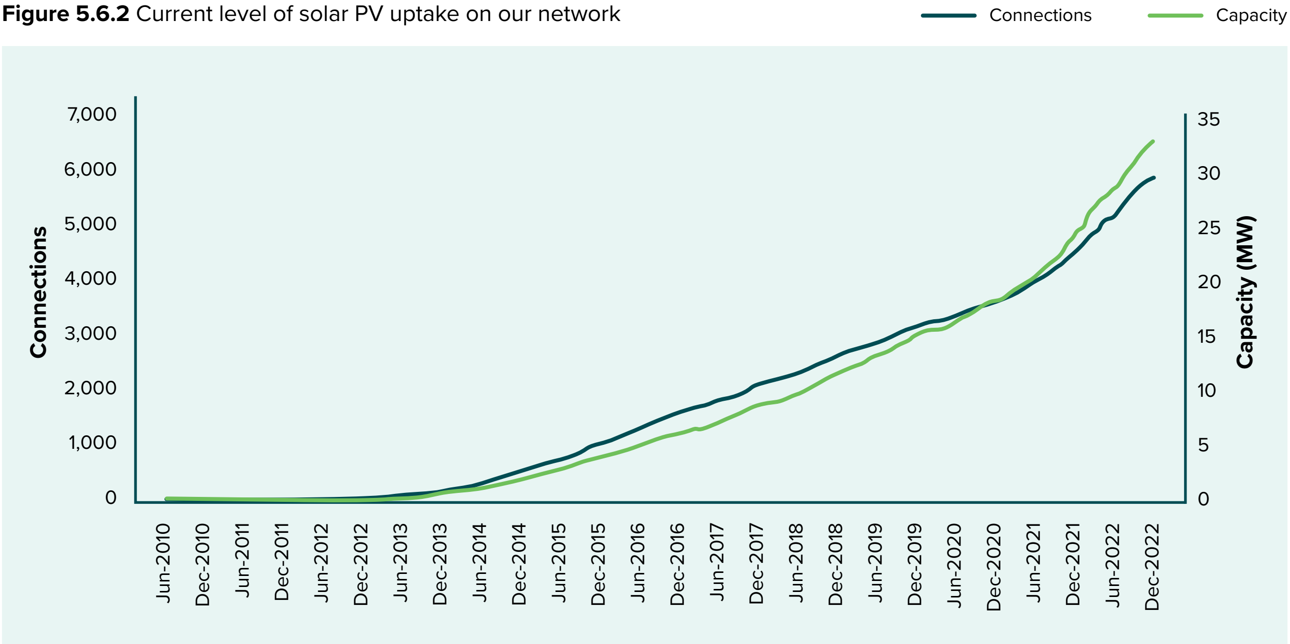
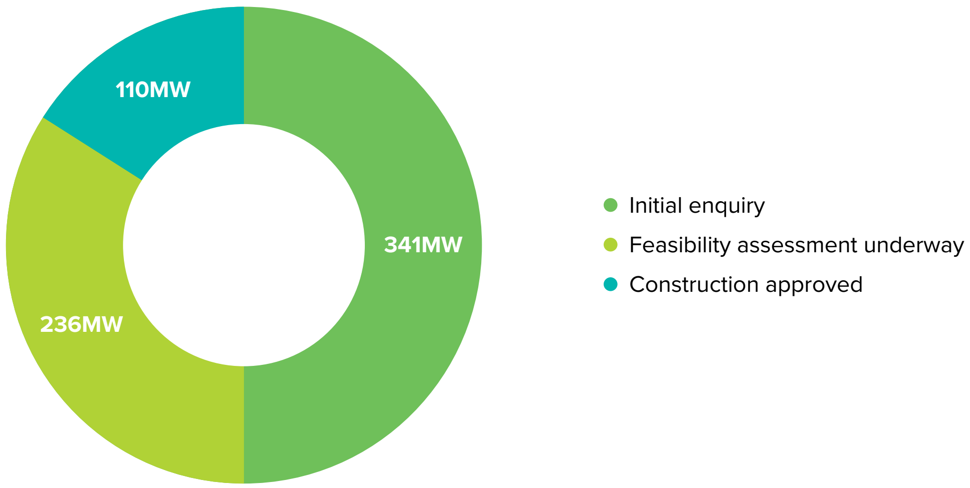


Figure 5.6.3 Utility scale solar applications – total 687MW



In the next few years we expect to see considerable utility scale solar installed on our network. Interest in utility scale solar connections is high with the number and capacity of potential applications on our network shown in Figure 5.6.3.

The impact of solar on our network depends on whether the solar is installed at household, business, or utility scale level.

In the next ten years we expect significant network investment to be driven by solar connections. This includes network upgrades to facilitate solar installs and mitigating potential voltage impacts. We will also need to monitor all types of solar installations for real time energy flows.

Process Heat Conversions

As part of the drive to decarbonise, businesses are moving away from fossil fuels to electricity and biomass for industrial processes and heating. To discover the likely extent of future electrical conversion, Orion engaged DETA Consulting in 2021 to identify and survey large thermal fuel boiler sites within the Orion region. DETA, in partnership with Orion and with the support of other key stakeholders Transpower, MBIE and EECA, discussed with each business the size of their loads and forecast what they were likely to convert to electricity or biomass.

In May 2022 this work estimated 55MW to 215MW of commercial and industrial load is likely to convert to electricity by 2035. The range of expected load conversions is due to uncertainty in the availability of biomass in commercial quantities in Central Canterbury. Virtually no biomass is produced locally.

Within this AMP, our forecasts for expenditure are based on a midpoint of 135MW.

We are working closely with the business owners identified in our study to find pathways to decarbonise their process heat systems and better understand their likely electrical requirements and timing.

In the next few years we expect to see considerable utility scale solar installed on our network.

5.6.1.2 Non-growth drivers of change

Climate adaption

Our infrastructure will be subject to more extreme weather conditions in the future due to climate change. This means we need to make some parts of our network more resilient if we are to maintain current levels of customer service.

Orion's report, Climate Change Opportunities and Risks, sets out how climate change will impact our business, and what we are doing to prepare for a changed future. Significant climate effects will be more frequent higher speed wind-storms, drier conditions increasing the risk of fire, sea level rise, and increased temperatures.

Within this AMP we have included climate adaption expenditure related to increased expenditure on tree trimming and overhead networks, to mitigate some risks in relation to wind and fire. The increased spend on overhead networks is a result of changes in overhead design standards that are required.

Longer term, we expect sea level rise will affect the planning, maintenance and replacement of our coastal assets, and higher temperatures will impact the performance of some equipment. These longer-term effects of climate change have not been included in this AMP. We are currently examining potential impact so costs associated with these matters may be included in the FY25 AMP. Some impacts from sea level rise on Orion depend on Government and Council positions on managed retreat versus mitigation such as building of sea walls.

Also, our climate adaption costs may change in the future given changing climate research. The latest research is indicating a decreased probability that temperature change will be kept to +1.5°C. Consequently, we are currently in the process of reviewing what changes would need to occur to our overhead design standard if temperature change was +3°C to +4°C, and what the cost would be if we needed to replace more of our higher altitude located poles due to worsening climate conditions.

Significant climate effects will be more frequent higher speed wind-storms, drier conditions increasing the risk of fire, sea level rise, and increased temperatures.

Community energy resilience

As our community becomes more reliant on electricity our customers will increasingly need a resilient electricity system. Coupled with the growing impact of climate change and the liklihood of an Alpine Fault earthquake, this means we need to consider whether reliance on a electricity network system alone is good enough.

In addition to reinforcing existing network assets and designs, decentralised designs must be considered as a complementary solution to reduce reliance on a central point of network failure. Microgrids and other distributed energy resources are likely to be an important tool for some communities to reduce the risk posed.

Orion will seek out and support alternative solutions for community energy resilience. This may involve such things as providing batteries and/or solar at emergency community hubs, and emergency EV charging facilities.

Batteries

Batteries could create opportunities to assist with network management. The way our customers use these could influence how we build the network. For example, customers may discharge batteries at expensive evening peak times, and recharge the batteries at cheaper times, reducing the network peak load.

Customer battery storage connected to our network has been increasing at ~2MWh/year since January 2019 with the average capacity per installation being 8kWh, see Figure 5.6.4. Although this is currently not significant, the flexibility battery storage can provide will influence the observed system peak as the installed capacity grows. Figure 5.6.5 shows the uptake rate of batteries picked up in 2022.

As the price of vehicle to grid technology declines, the need for standalone batteries in homes is expected to reduce.

Figure 5.6.4 Current level of battery storage uptake on Orion network

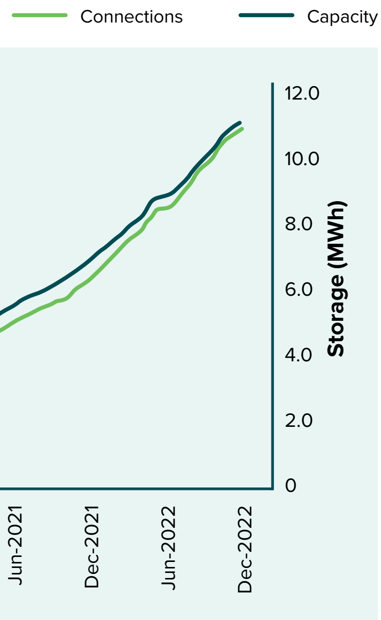
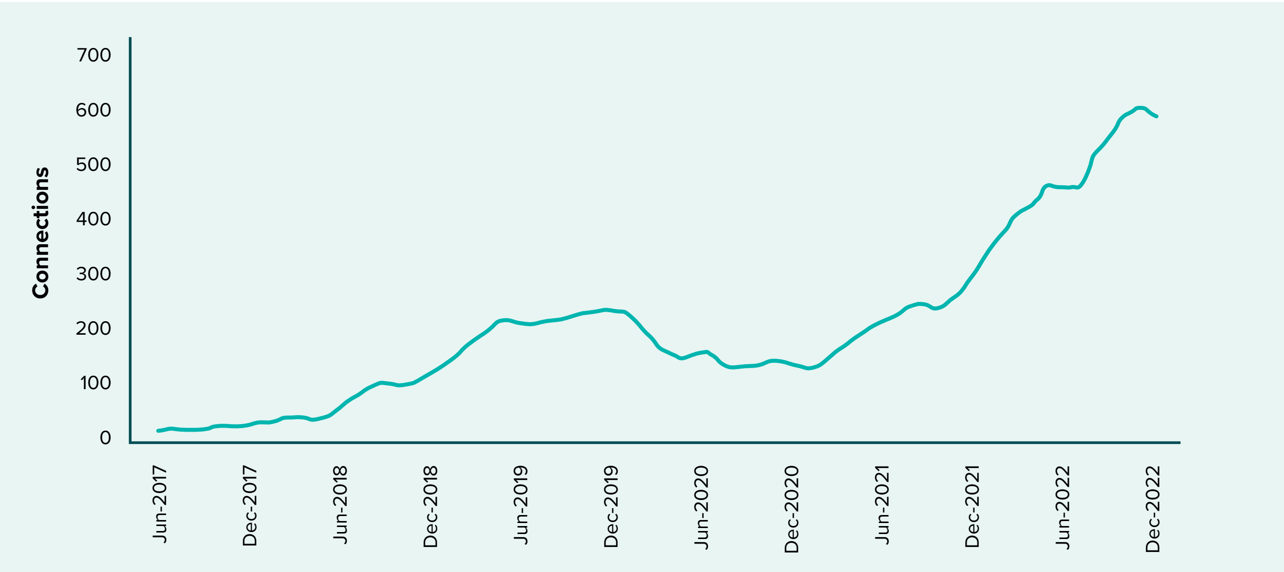


Figure 5.6.5 Rolling 12 month increase in battery connections



Smart systems

Transitioning to a future where customers can participate in electricity markets will require considerable effort and investment in smarter systems and controls. Lower cost alternatives to network build will need to be enabled, two-way flow of power seamlessly managed, and the network operated efficiently.

To meet these challenges, Orion has developed a Network Transformation Roadmap to deliver the following high-level outcomes by 2030:

- significant enhancement of the sustainable connection of new technology to our distribution network
- trading of energy and capacity between customers and market participants via an open network framework is enabled
- our planning, investment and operational capabilities in service of the above are significantly augmented

To achieve these outcomes, improvements in our systems are targeted in the planning period, including:

- enhanced network monitoring such as installing low voltage monitoring equipment on our transformers and feeders, and receipt of and analysis of smart meter network data
- digital platforms that reduce the cost and improve the efficiency and effectiveness of our core network operations
- improved network condition and utilisation monitoring
- communicating/interfacing with customer owned equipment, such as batteries and EVs
- deterministic and probabilistic modelling, with advanced scenario-based forecasting
- dynamic operating systems
- enhancing our Advanced Distribution Management System (ADMS) to enable improved grid efficiency and resiliency to allow us to remotely respond to outages and other grid conditions quickly and safely

The cost to develop and operate these smarter systems and controls is included in this AMP.

5.6.1.3 Scenario planning

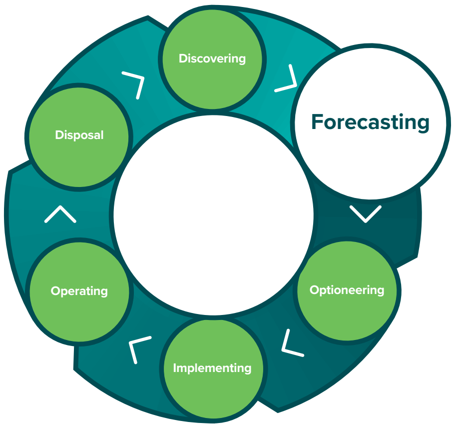
We are widening our future energy scenario planning to a greater range of growth drivers to examine a variety of possible futures.

Projections for future growth based on historical trends is no longer suitable for asset management planning. We now need to forecast emerging and uncertain trends and new markets. As it is not possible to forecast these with any certainty, we consider the range of uncertainty and the spread of potential pathways for each growth driver.

Orion is developing a set of high-level future energy scenarios of the different potential pathways for energy sector transition and industry development. Our scenarios will be consistent with those developed across the rest of the energy sector, in particular, Transpower's Te Mauri Hiko report and The Ministry of Business Innovation and Employment's demand and generation scenarios.

Scenario modelling will allow Orion to better plan for future changes to the network. By modelling different pathways we will develop a deeper understanding about the potential range of outcomes, and the drivers or inflection points for shifting between pathways. It will lead us to least regrets network planning actions we can take that will be useful under many, or all, of the different future pathways.

5.6.2 Forecasting



Our network development forecasts project future demand for electricity on our network from the inputs analysed in the 'Discovering' phase. Our forecasting process is evolving as we look to improve our scenario-based approach. Our forecasting is both at a system level, total energy growth and total network maximum demand, and at a local level.

5.6.2.1. Energy growth

Energy usage forecasts are used by Orion to assist in determining our prices. Our average system energy throughput for the past 30 years is shown in Figure 5.6.6.

5.6.2.2 Maximum demand

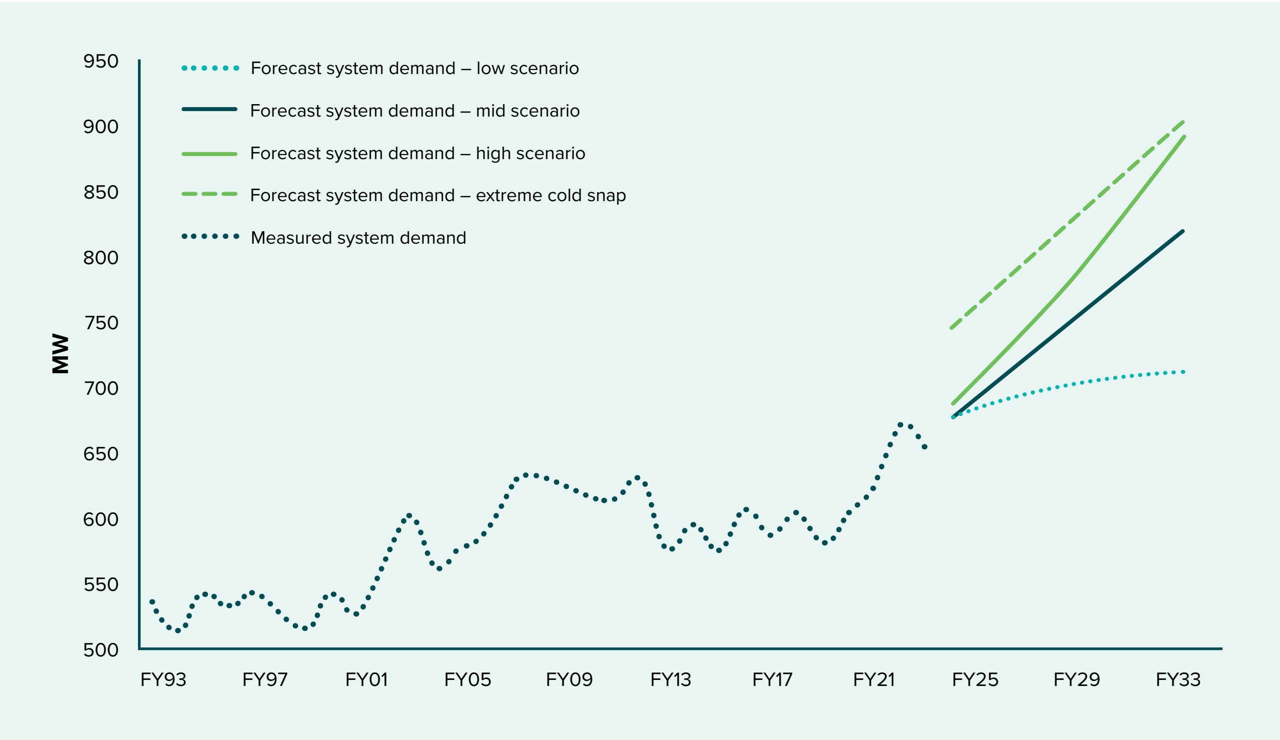
As maximum demand is the major driver of investment in our network, it is important for us to forecast it as accurately as we can. For this reason, we forecast maximum demand across all levels of our network.

On a year-to-year basis, maximum demand is volatile and can vary by up to 10% depending on winter weather. Our network maximum half hour demand for FY23 was 654MW during the evening peak that occurred on 11 July 2022, down 18MW from the evening peak in the previous year.

For long-term forecasts, we produce low, mid, high, and extreme cold snap maximum demand forecasts as shown in Figure 5.6.7. These forecasts consider our expectations for several different growth drivers, including those set out in Section 5.6.1.1. Our maximum demand forecast assumes solar photovoltaics have no effect on the network peak, as we forecast our peak will continue to occur on a winter evening, when the sun isn't shining.

Figure 5.6.6 Energy throughput on Orion network

Figure 5.6.7 Overall maximum demand trends on the Orion network



5.6. Managing growth and change continued

Winter peak demand on our network is anticipated to increase by approximately 170MW (26%) over the next 10 years. This is based on the mid scenario forecast for system demand shown in Figure 5.6.7.

Descriptions of the four scenarios forecast for system demand are:

- **Low** – the low forecast is based on continued customer actions reducing load by 0.5% per annum and battery storage, in either stationery or mobile form, being used to counter the impact of electric vehicle charging at peak – that is batteries inject power at peak. The rate of coal boiler conversions to electricity is half that used in the mid forecast
- **Mid** – this indicates underlying growth from new residential households, industrial uptake and commercial rebuild. For EVs we have used Ministry of Transport potential uptake figures as a baseline. This assumes ~16% of the region's vehicle fleet will be electric in 10 years and we have assumed 20% charging at peak times.

  Customer actions continue to reduce peak demand by 0.5% per annum. We expect new business and residential buildings will be more energy efficient than the older buildings they replace. An allowance for coal boiler conversions has been included as discussed in Section 5.6.1.1.

  This forecast does not include the effects of batteries.
- **High** – this high forecast shows the consequences of further energy efficiency gains becoming unattainable, coal boiler conversions matching the mid forecast and a trebling of the electric vehicle impact to match the highest scenario from the Climate Change Commission.
- **Extreme cold snap** – this forecast is based on events like those in 2002 and in 2011 when a substantial snowstorm changed customer behaviour. We experienced a loss of diversity between customer types. There was significant demand from residential customers due to some schools and businesses remaining closed. When planning our network, it is not appropriate to install infrastructure to maintain security of supply during a peak that may occur for two or three hours once every 10 years. This forecast is therefore used to determine nominal – all assets available to supply – capacity requirements of our network only.

5.6.2.3. Low voltage constraints

Over the past four years Orion has worked in collaboration with, and commissioned various studies from EPECentre at the University of Canterbury to forecast the potential impact of electric vehicles and residential batteries on our low voltage network, down to street level.

The studies focussed on residential areas which were more likely to experience residential infill and EV clustering.

Constraints were defined as:

- Transformers operating above 100% rated current
- Cables/Lines operating above 100% rated current
- Cables/Lines operating outside voltage regulations (230V ± 6%)

The results from this work enabled us to identify LV feeders which will be most vulnerable to load changes arising from the adoption of EVs and residential batteries. A summary of the constraints identified are shown in Figure 5.6.8.

Our EV modelling to date indicates most of our low voltage network has sufficient capacity to meet demand in the short to medium term.

In the longer term, as EV adoption increases, our region's population grows and housing intensification increases, reinforcing our network will be required.

We are currently reviewing our LV strategy and have increased our forecast reinforcement budget to address expected constraints in the future.

Our forecasts of capacity and constraints on our LV network will be reviewed and adjusted with the knowledge we gain over the next few years from increased data on our LV network and information on how new technology is being used in homes.

In the longer term, as EV adoption increases, our region's population grows and housing intensification increases, reinforcing our network will be required.

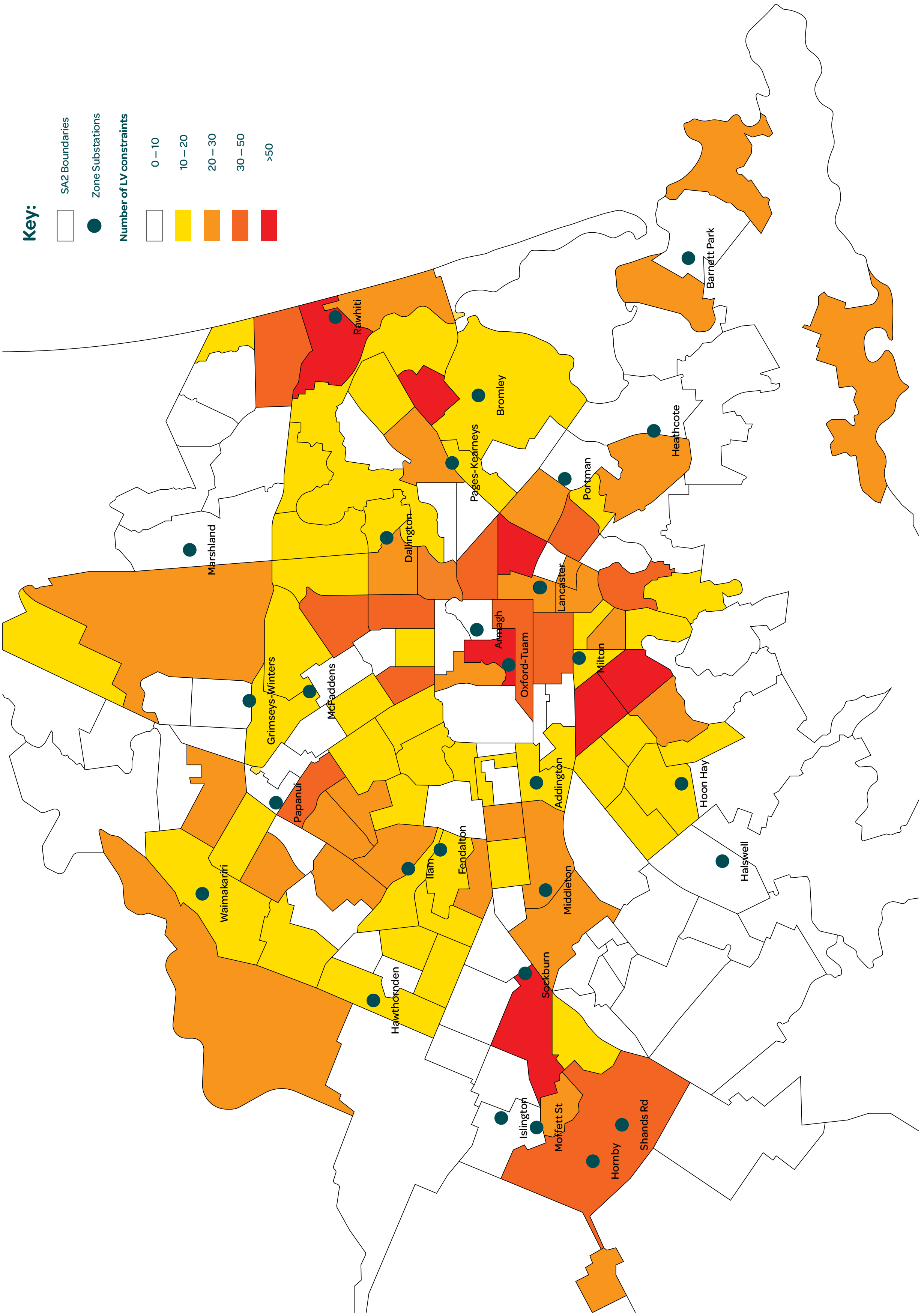
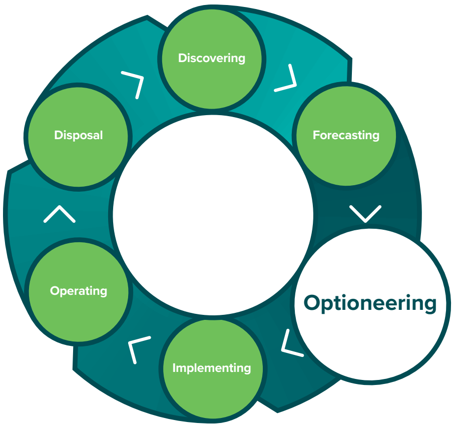


Figure 5.6.8 Projected LV urban network constraints in 2030 grouped by Statistics NZ SA2 definitions

5.6.3 Optioneering



When preparing for growth, we consider a variety of solutions to address forecast constraints on the network, including traditional reinforcement and alternative solutions as set out in Section 5.3.1. When we determine which option delivers the best value for consumers we consider the technically feasibility, cost and wider system impacts.

One of the first steps in weighing up our options is to consider the type of constraint that has been forecast including where it occurs, when and how long it is expected to happen. Some constraints will be very location specific, for example an LV feeder, and others widespread. Some constraints may only be forecast for several hours per year; and others will be frequent.

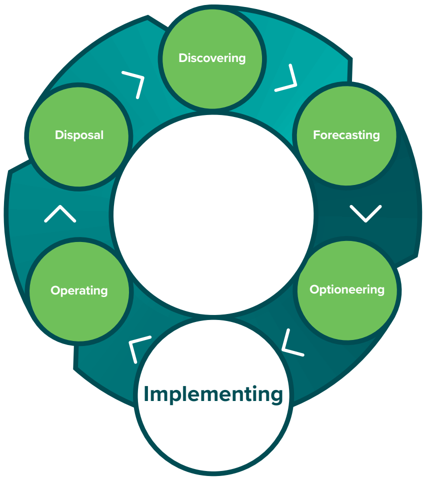
With the constraint identified, we assess the options to address it. Once an option has been selected, projects are prioritised as per the framework set out in Section 5.4.2.

The decision tree in Figure 5.6.9 demonstrates some of the factors considered when optioneering.

Some options deliver social, environmental, and whole-of-system benefits that are difficult to quantify. At times, this means the best option for our customers overall may not align with the lowest cost option for Orion. We also recognise that decarbonisation is causing a fundamental change to the way we operate, and we increasingly seek to consider the 'whole-of-system' impact in our decision-making approach.

The market for contracted flexibility services in New Zealand is still being developed, as is the framework for assessing these against traditional solutions. We are collaborating with other EDBs through the FlexForum and Electricity Network Association to develop a common framework to support evaluation of flexibility service options.

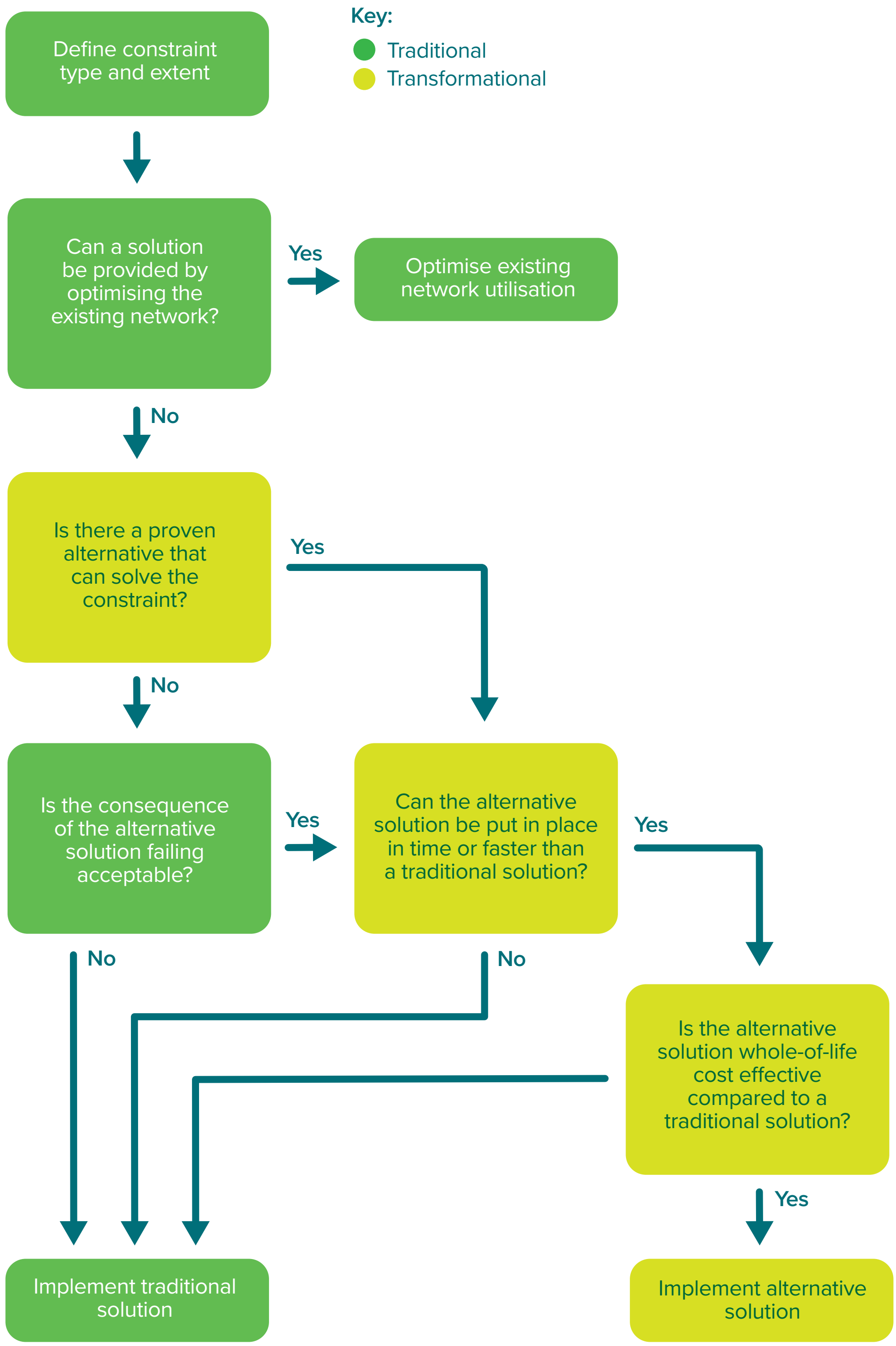
5.6.4 Implementing



In order to implement our network development plans, we follow the same processes and procedures laid out for our asset lifecycle programmes, see Section 5.5.4.

Section 7 outlines our network development projects we plan to deliver over the next 10 year period to meet our network and customer needs to support an accelerated energy transition to meet New Zealand's decarbonisation goals.

Figure 5.6.9 Optioneering process



6 Managing our assets

Photo: Orion's Hawthornden substation.

Contents

Contents continued

6.1 Introduction

We take a whole of life approach to managing our assets. In the process we develop maintenance plans and replacement plans which are discussed in Section 5.5.

The price quality trade-off is important when developing our forward works programme. We have engaged with our customers in a number of forums, see Section 4, and the consensus is that they are satisfied with our current levels of network performance.

Orion has taken a proactive approach to managing our assets with our maintenance and replacement programmes. We believe a planned approach is in the long-term interest of our customers as it minimises outages, addresses assets on a risk basis and is more cost effective. A secondary advantage is that a consistent flow of work maintains the competencies of our people and service providers which means our customers benefit during adverse events through the quality and timeliness of emergency repairs.

Replacement programmes for our poles and switchgear assets dominate our capital expenditure forecast.

The driver for these programmes is to continue addressing the potential safety consequences of asset failure.

Events that materially impact our network are caused by weather, vegetation and plant failure. We reduce the impact of these events by conducting regular proactive programmes where approximately 70% of our network operational expenditure is spent on inspections, maintenance and vegetation management. The remaining 30% is spent on responding to service interruptions and emergencies, the majority of which occur on our overhead network and are due to weather related causes.

Both operating and capital expenditure for managing our assets is forecast to increase over the planning period, see Figures 6.1.1 and 6.1.2. This will ensure our network can withstand the effects of climate change as we face changes in temperature, rainfall, extreme weather events, wind and increased fire risk due to weather. Our expenditure forecasts include allowance for vegetation maintenance, and climate adaptation of our distribution kiosks and overhead system.

Our planned expenditure on programmes to ensure our network is equipped to meet a changed future will enable us to maintain the current service levels for our customers.

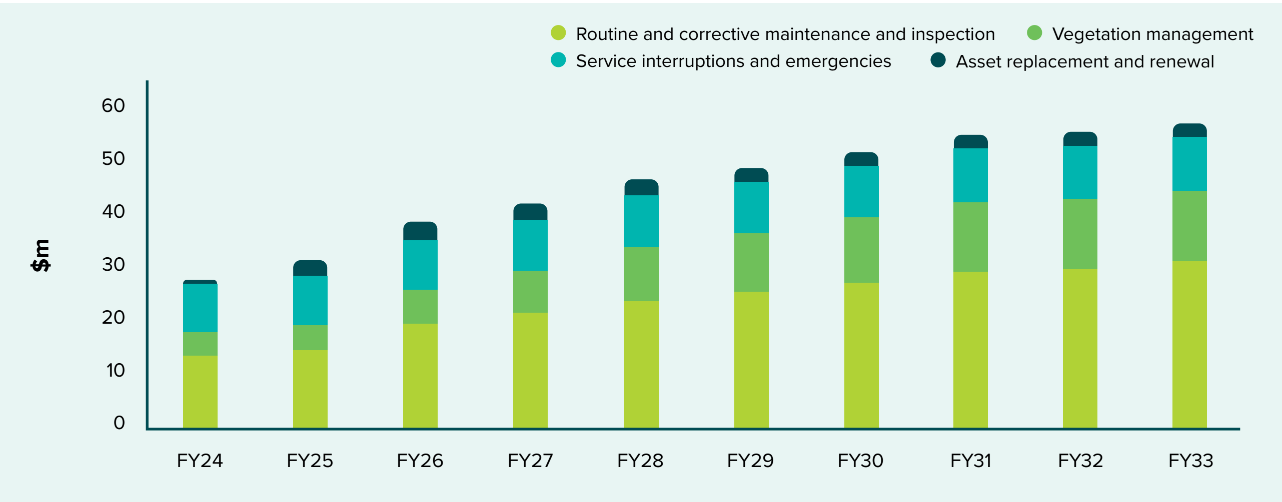
We will continue to gather improved information on the condition of our assets to make better informed investment decisions on our ageing end of life fleet.

A component of the increase in our expenditure is also due to upward pressure on costs because of supply chain issues, and increased safety and traffic management requirements. These increases, while substantial, are unavoidable.

Our planned expenditure on programmes to ensure our network is equipped to meet a changed future will enable us to maintain the current service levels for our customers.

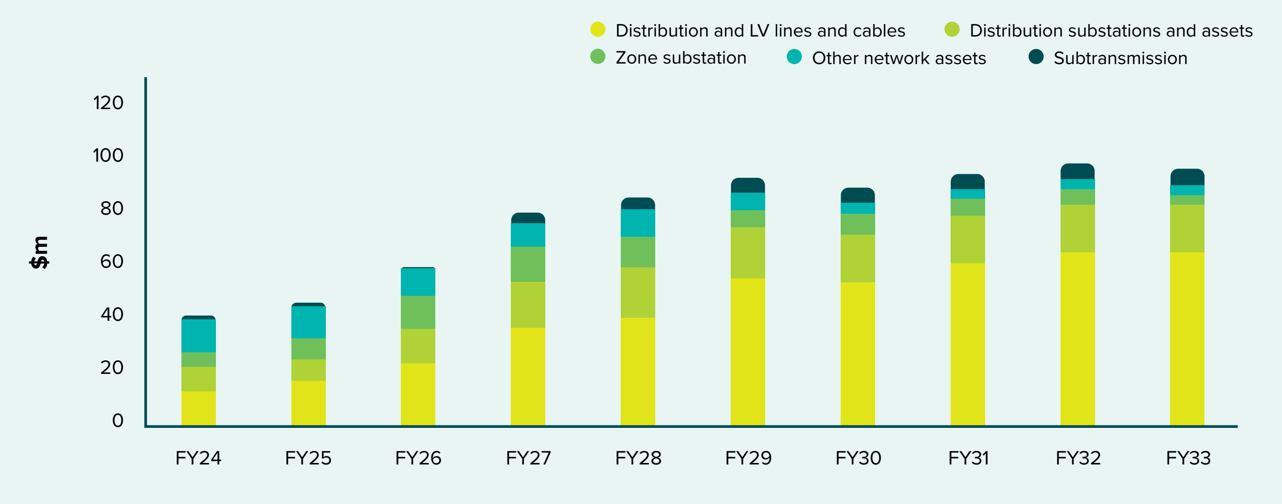
This section only includes operational costs relating to physical assets. Refer to Section 8 for other business support expenditure.

Figure 6.1.1



6.1 Introduction continued

Figure 6.1.2



6.2 How this section is structured

In the following Sections 6.3 to 6.20 for each asset class we have taken a consistent approach to describing the assets, their current health and our plans for inspection, maintenance and replacement. For each asset class we provide:

Summary

A summary of the current state, any issues and plans for the asset class.

Asset description

A brief description giving the type, function, voltage levels and location and distinct components of each asset class. The number of units will also be provided together with the age profile.

Asset Health

Condition

The health of an asset represents the asset's current condition as a Health Index (HI) profile. An age profile is also provided if not already outlined in the asset description. We use the CBRM models to calculate the HI and Probability of Failure (PoF) of each individual asset.

The Health Index definitions are:

- **H1:** replacement recommended
- **H2:** end of life drivers for replacement present, high asset related risk
- **H3:** end of life drivers for replacement present, increasing asset related risk
- **H4:** asset serviceable, no drivers for replacement, normal in-service deterioration
- **H5:** as new condition, no drivers for replacement

Reliability

We look at the performance of the asset class, in relation to its contribution to SAIDI and SAIFI or faults per 100km.

Issues and controls

A table is provided to outline the failure causes and mitigation or control measures for the asset category. This provides context for the asset condition, maintenance and replacement plans.

Maintenance plan

Here we provide the scheduled maintenance work plans that keep the asset serviceable and prevent premature deterioration or failure. A summary of the asset class' maintenance strategy, the maintenance activity and frequency is also provided. Maintenance expenditure forecasting is based on known historical maintenance costs and our projected maintenance programmes.

Replacement plan

These are major work plans that do not increase the asset's design capacity but restore, replace or renew an existing asset to its original capacity. We also briefly outline the options we explore in optimising the replacement work if they are additional to those described in Section 5.6.2. A summary of upcoming programmes and work is also included. Replacement expenditure forecasting is based on known historical replacement costs and projected replacement volumes.

Disposal

We list any of the activities associated with disposal of a decommissioned asset.

This section covers more than 12,000 buildings, substations, kiosks and land assets that form an integral part of Orion's distribution network.

6.3 Network property

6.3.1 Summary

This section covers more than 12,000 buildings, substations, kiosks and land assets that form an integral part of Orion's distribution network. Our distribution substation buildings vary in both construction and age. Around 150 of our substations are incorporated in a larger building that is often customer owned.

The capital expenditure for this AMP period is focusing on replacing ageing high top kiosks and climate adaptation of distribution substations and kiosks in areas that are vulnerable to increased flooding or higher summer temperatures.

6.3.2 Asset description

6.3.2.1 Zone substation

A zone substation is a site housing high voltage infrastructure that is an important hub in our network.

It includes buildings, switchgear, transformers, protection and control equipment used for the transformation and distribution of electricity. Majority of the building construction types are concrete block, followed by modular, tilt slab and brick. Orion's zone substations, see Table 6.3.1, generally include a site where one of the following takes place: voltage transformation of 66kV or 33kV to 11kV, two or more incoming 11kV feeders are redistributed or with ripple control plant is installed.

Table 6.3.1 Zone substation description and quantity

Voltage	Quantity	Description
66kV	1	Marshland is a 66kV indoor switching station and future zone substation located in Region A
33kV	1	Islington is a 33kV GXP connected switching station and zone substation that supplies the Region A 33kV / 11kV zone substations
66kV / 11kV	28	Of the 28 there are 19 in Region A. 9 of those are urban substations and have an exposed bus structure. The Armagh, Dallington, Lancaster, McFaddens, Waimakariri and Belfast structures are inside a building. 9 in Region B are supplied by overhead lines (Brookside, Dunsandel, Highfield, Killinchy, Larcomb, Kimberley, Greendale, Te Pirita and Weedons). All have outdoor structures
66kV / 33kV & 66kV / 11kV	1	Springston rural zone substation is supplied by an Orion tower line from Transpower's Islington GXP
33kV / 11kV	16	These are mainly in the Canterbury rural area and on the western fringe of Christchurch city. Most have some form of outdoor structure and bus-work Zone substations at Annat, Bankside and Little River have 66kV structures but are currently operating at 33kV
11kV	4	These are all in Region A. They are directly supplied by either three or four radial 11kV cables and do not have power transformers. None of the 11kV zone substations have any form of outdoor structure or bus-work. We have had the opportunity to decommission some 11kV zone substations rather than replace them due to the changing load profile in certain parts of the network
Total	**51**	

6.3 Network property continued

6.3.2.2 Distribution substation

The different types of our distribution substations are shown in Table 6.3.2. Where our equipment is housed in buildings, many of these are owned by our customers.

Table 6.3.2 Distribution substation type

Type	Quantity	Description
Customer building	205	Customer substations are typically Orion substations contained within a customer's building. They usually contain at least one transformer with an 11kV switch unit and 400V distribution panel. There may also be 11kV circuit breakers or ring main units
Orion building	250	Orion owned substation buildings are normally stand-alone buildings. They vary in size and construction
Kiosk	3,323	Our kiosks are constructed of steel to our own design and manufactured locally. The majority fall into two categories; an older high style, and the current low style Full kiosks vary in size and construction but usually contain a transformer with an 11kV switch unit and a 400V distribution panel
Outdoor	870	These vary in configuration, but usually consist of a half-kiosk with 11kV switchgear and a 400V distribution panel as per a full kiosk. An outdoor transformer is mounted on a concrete pad at the rear or to the side of the kiosk
Pole	6,409	Single pole mounted substations usually with 11kV fusing and a transformer
Pad transformer	839	These are a transformer only, mounted on a concrete pad and supplied by high voltage cable from switchgear at another site. Transformers are generally uncovered
Switchgear cabinet	193	Cabinets that contain only 11kV switchgear
Totals	**12,089**	

6.3.3 Asset health

6.3.3.1 Condition

Our zone substation buildings are well designed and mostly constructed with reinforced and concrete filled blocks.

Prior to the Canterbury earthquakes in 2010 and 2011 we undertook a 15-year programme to seismically strengthen our zone and distribution substation buildings. We completed the programme before the Canterbury earthquakes and recognised an almost immediate benefit for our community.

Our kiosks are generally in reasonable condition. Steel kiosks in the eastern suburbs nearer the sea are more prone to corrosion and we will replace these kiosks much sooner than those in the remainder of our network. We attend to these kiosks as needed, based on information from our condition surveys, and we now have a stainless-steel design option to guard against corrosion. The age profiles are shown in Figures 6.3.1 and 6.3.2.

Steel kiosks in the eastern suburbs nearer the sea are more prone to corrosion and we will replace these kiosks much sooner than those in the remainder of our network.

Figure 6.3.1 Substation buildings age profile by zone substation and distribution substation

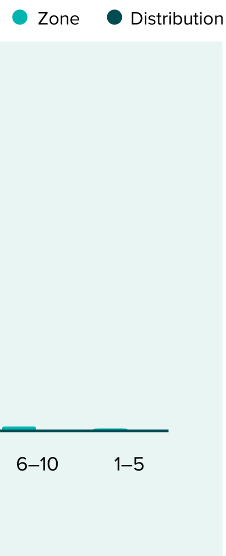
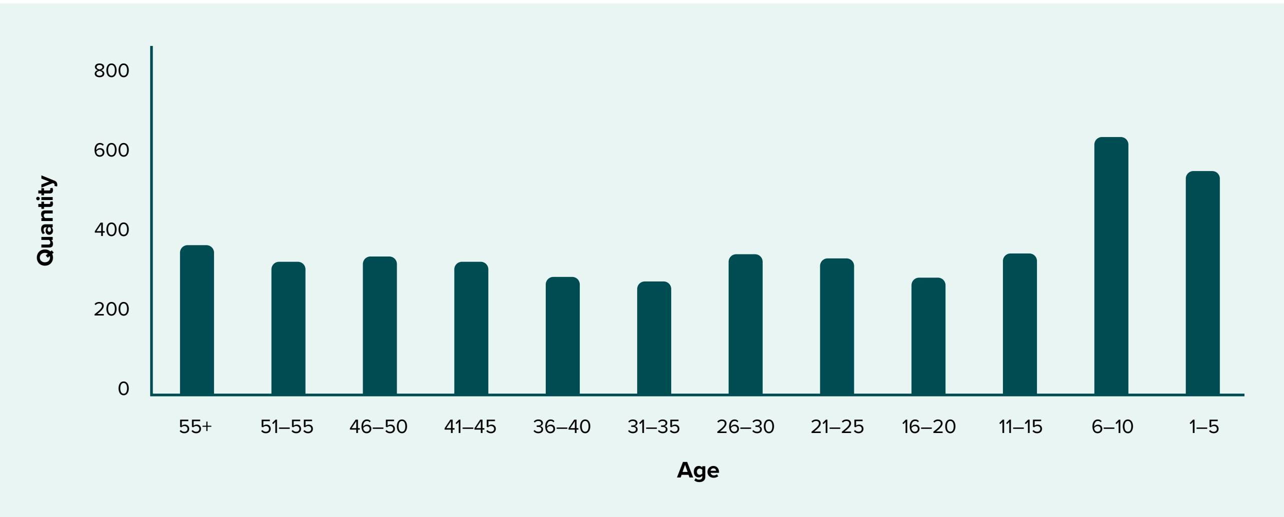


Figure 6.3.2 Kiosk age profile



6.3 Network property continued

6.3.3.2 Reliability

The reliability of the equipment is not impacted by the buildings or housings, providing they are kept secure. Orion rigorously controls security and entry to its substations, with regular monitoring of site security.

6.3.3.3 Issues and controls

Table 6.3.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 6.3.3 Network property issues / controls

Common failure cause	Known issues	Control measures
Third party interference	Unauthorised and illegal entry onto our sites poses a risk to the persons health and safety	Substation access is controlled via a hierarchical key system, with users being issued access levels based on their competencies. Zone substations have an additional outer boundary barrier such as locked gates, fencing and walls to reduce unauthorised access. Switchyard fencing have additional entry deterrents including tall fencing with electrified top wires or razor/barb wires. Some critical sites are also monitored with security cameras. Switchyard and building doors are monitored via SCADA for "left open" status. As part of our regular inspection routine, we verify the security and entry systems at all substation sites
	Lost or stolen substation keys could be used for illegal access	To enhance the security of zone substation sites, we will implement a program to upgrade access systems with electronic access and identification technology
	Vegetation in and around our assets poses an operational safety hazard	We conduct planned and reactive grounds maintenance programmes
	Graffiti, which is generally visually unappealing to the public	Graffiti is managed through a ground maintenance and graffiti removal programme
Structural and environmental issues	Access to our assets can be restricted if contained within buildings susceptible to earthquake damage	We have completed a seismic strengthening programme
	Asbestos in Orion and privately owned sites contained within the building materials poses a risk to the health of our staff and service providers	Asbestos management plan and asbestos registers, training and education. Procedures and Accidental Discovery Processes (ADP) established
	Work on contaminated land poses a health risk to our people and public and can cause more harm to the environment	ADP are established to control health and environmental risks
Deterioration	Water-ingress into buildings can damage our assets	We conduct routine building inspections and maintenance
	Old wooden substation doors require more maintenance and are not as secure as newer aluminium doors	We replace old wooden doors with aluminium doors

6.3.4 Maintenance plan

The substation monitoring and inspection programmes are listed in Table 6.3.4. Our forecast operational expenditure, Table 6.3.5, is in the Commerce Commission categories.

Table 6.3.4 Network property maintenance plan

Maintenance activity	Strategy	Frequency
Zone substation maintenance	Substation Building Condition Assessments are carried to identify the substation maintenance requirements	2 years
Zone substation grounds maintenance	Grounds are adequately maintained, switchyard is free of vegetation and gutters and downpipes are free of any blockages	Each site is visited once every 3 weeks
Distribution substations	Visual inspection of all the components and includes recording any transformer loading (MDI) value. Vegetation issues are also reported and cleared	6 months
Graffiti removal	We liaise with the local authorities and community groups in our area to assist us with this problem. We also now have in place a proactive graffiti removal plan where our service providers survey allocated areas of the city and remove graffiti as they find it	The sites which go through the reporting process are attended usually within 48 hours
Kiosks	Inspection rounds identify any maintenance requirements Grounds maintenance ensuring clear and free access to kiosks is undertaken on urban sites Grounds maintenance on rural sites is undertaken We maintain and repaint our kiosks as required with more focus to deter rust on the coastal areas	6 months 2 years As required As required
Substation earthing	A risk-based approach has been taken for the inspecting and testing of our site earths. In general, earth systems in our rural area are subject to deterioration because of highly resistive soils, stony sub-layers of earth and corroded earthing systems	Between 2,000 and 2,600 sites are tested in any year and those sites requiring repairs are scheduled for remedial work in the following year
Roof refurbishment programme	A number of our substation buildings were constructed with a flat concrete roof with a tar-based membrane covering. These have been prone to leaking when cracks develop in the concrete. We upgrade these buildings by constructing a new pitched colour steel roof over the top	Roof replacement is scheduled and prioritised as required, based on survey data

6.3 Network property continued

Table 6.3.5 Network property operational expenditure (real) – $000											
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	120	120	120	120	120	120	120	120	120	120	**1,200**
Routine and corrective maintenance and inspections	2,921	2,918	3,018	3,033	3,043	2,998	3,018	2,998	3,018	3,008	**29,974**
Asset replacement and renewal	95	95	95	95	95	95	95	95	95	95	**950**
Total	**3,136**	**3,133**	**3,233**	**3,248**	**3,258**	**3,213**	**3,233**	**3,213**	**3,233**	**3,223**	**32,124**

6.3.5 Replacement plan

Due to the outdated design of certain older high top kiosks, additional site modifications will be required to replace them with more modern counterparts. As a result, additional funds have been allocated as more of this type come up for replacement. Budgetary allocation has also been placed from FY27 onwards for the adaptation of distribution substations and kiosks to mitigate the effects of climate change, specifically for locations that are vulnerable to increased flooding or higher summer temperatures.

Other replacement programmes covered in Table 6.3.6 are:

- Ongoing replacement of our substation ancillary equipment such as battery banks and battery chargers
- Replacement programme to address safety and seismic risk of some older pole substation sites by upgrading the substation design to current standards
- Upgrade security fencing
- Targeted replacement of steel kiosks located near the coast due to rust
- Upgrade access systems to include electronic access and identification to enhance security at zone substation sites

Table 6.3.6 Network property replacement capital expenditure (real) – $000											
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Zone substations	380	100	100	100	100	100	100	100	100	100	**1,280**
Distribution substations and transformers	739	572	572	1,966	1,756	1,756	1,756	1,756	1,756	1,756	**14,385**
Other network assets	434	377	261	261	261	261	261	261	261	261	**2,899**
Other reliability safety and environment	320	700	700	700	-	-	-	-	-	-	**2,420**
Total	**1,873**	**1,749**	**1,633**	**3,027**	**2,117**	**2,117**	**2,117**	**2,117**	**2,117**	**2,117**	**20,984**

6.3.5.1 Disposal

We assess ownership of interests in a property, in particular easements on unused sites. We will relinquish ownership of these sites as and when required. The procedures for disposal are shown in Table 6.3.7.

Table 6.3.7 Procedures for disposal

Disposal type	Controls and procedures
Land	Prior to disposing of land, we undertake due diligence investigations on environmental and property matters as considered appropriate
Asbestos	We have guidelines and a management plan for the disposal of asbestos which mandate the appropriate disposal of asbestos as part of our service provider's safe work methods
Contaminated Land	Our asset design standards for substations contain information on how to risk assess works in and around potentially contaminated land and mandates the use of suitably qualified and experienced personnel to advise on appropriate disposal options where required. A network specification details disposal requirements and options for all work relating to excavations, backfilling, restoration and reinstatement of surfaces

More than 50% of our 66kV poles are less than 20 years old and are well within their life expectancy.

6.4 Overhead lines – subtransmission

6.4.1 Summary

Our subtransmission network spans 506 kilometers and is the backbone of our service to customers. These lines are supported by 396 towers and 5,405 poles. Any failure of our subtransmission network has the potential to severely affect our safety and performance objectives, and disrupt our customer's lives.

Overall, Orion's subtransmission lines are in serviceable condition. Our asset management strategy and practices for our tower fleet ensure we achieve the best possible lifecycle outcomes.

We are developing a painting programme for our towers to extend their lifecycle. This makes up majority of the maintenance expenditure, together with regular condition inspections. Each year we reconstruct parts of our subtransmission network which are near end of life by replacing poles and end of life components such as insulators, crossarms and conductors.

6.4.2 Asset description

Here we describe our 33kV and 66kV overhead line asset components. For a map and detailed description of our subtransmission network configuration see Section 7.

Our subtransmission overhead asset has three distinct components; towers and poles; tower and pole top hardware; and conductors.

Towers

Our towers are steel lattice type, supported by different foundation types to maintain the stability and functionality of our overhead subtransmission network. Most are a mixture of concrete footings and grillage. Grillage is a framework of crossing beams used for spreading heavy loads over large areas. Used in the foundations of towers, steel grillage was buried directly into the ground for tower foundations in the 50s and 60s, and more recently it is encased in concrete.

Poles

We use three types of poles:

Timber – hardwood and softwood. Hardwood has superior strength over softwood poles due to its dense fibre characteristics. The expected life of hardwood poles depends on timber species, preservative treatment and configuration. Timber poles in areas in areas of harsh environment conditions have a reduced service life

Concrete – prestressed concrete poles have superior tensile strength compared to precast concrete. We no longer install precast poles on our network

Steel – we have 16 steel monopoles specifically designed to suit their location and span length

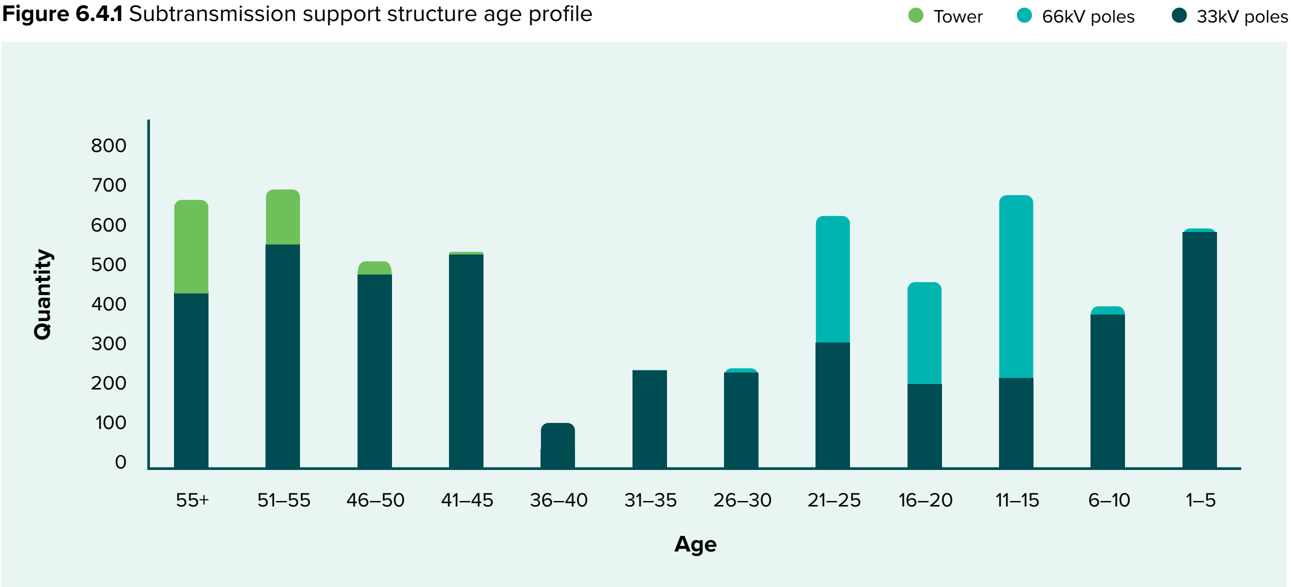
For a detailed table of poles by type see Table 6.4.1.

The age profile is shown in Figure 6.4.1. More than 50% of our 66kV poles are less than 20 years old and are well within their life expectancy. The life expectancy for timber poles is 45 to 55 years, 80 years for concrete poles and 60 years for steel poles.

Table 6.4.1 Subtransmission support structure type

Type	66kV	33kV	
	Quantity	Quantity	Total
Hardwood pole	998	2,305	3,303
Softwood pole	35	426	461
Concrete pole	25	1,599	1,624
Steel pole	15	2	17
Steel tower	396	-	396
Total	**1,469**	**4,332**	**5,801**

Figure 6.4.1 Subtransmission support structure age profile



Tower hardware
Tower hardware is attached directly to the steel lattice structure. It consists of mainly glass disc assemblies in strain and suspension configurations along with some polymer post insulators.

Pole top hardware
Pole top hardware supports the overhead conductors on the pole. It consists of crossarms and braces, insulators, binders and miscellaneous fixings. Crossarms are constructed of hardwood timber or steel. Orion uses hardwood timber crossarms which have an expected life of 40 years.

We have porcelain, glass disc and composite insulators installed on our network as well as line post, pin and strain types.

Conductors
The conductor types used in our subtransmission overhead network are largely aluminum conductor steel reinforced cable (ACSR) and hard drawn copper (HD). Their different attributes are:

ACSR – a stranded conductor used extensively on our HV network. This conductor is chosen for its high strength good conductivity and lower cost when compared to copper. It performs well under snow, wind and ice environments.

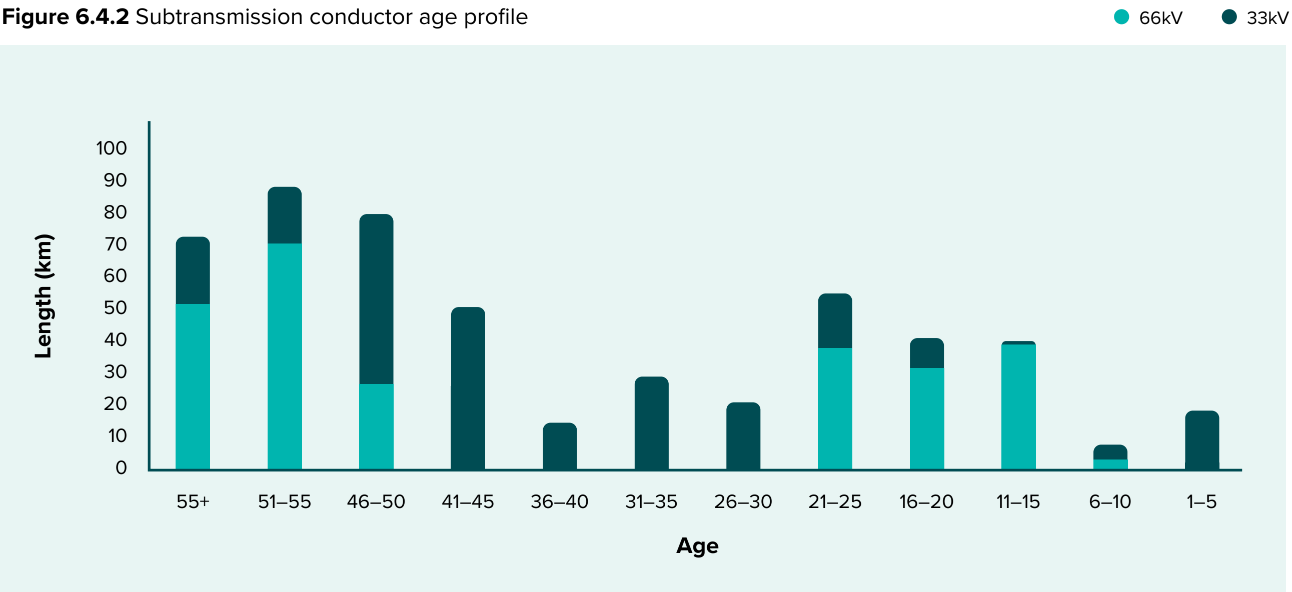
HD – hard drawn stranded copper conductors are installed on our LV and HV networks, excluding 66kV. Due to its cost and other modern alternatives we now only install it on our LV network when we do replacement works.

Details of conductor type and age profile can be found in Table 6.4.2 and Figure 6.4.2.

Table 6.4.2 Subtransmission conductor type

Type	66kV	33kV	
	Length (km)	Length (km)	Total
ACSR	244	206	450
HD copper	15	36	51
Total	**259**	**242**	**501**

Figure 6.4.2 Subtransmission conductor age profile



6.4.3 Asset health

6.4.3.1 Condition

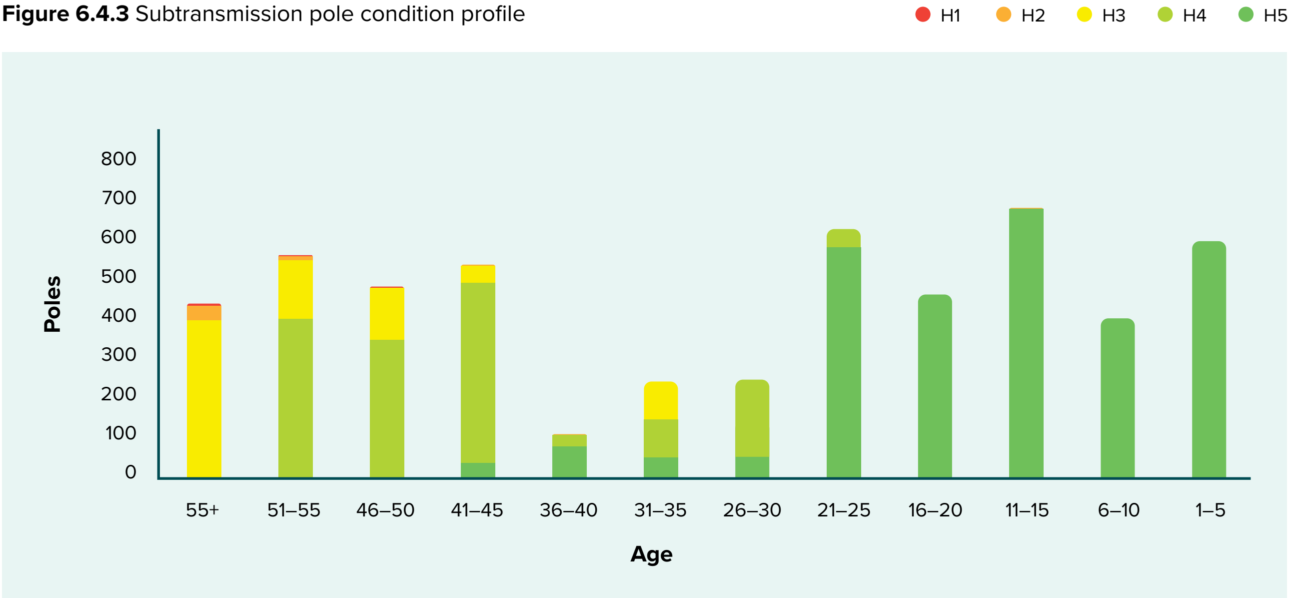
Towers

The Transpower spur assets - Addington and Islington to Papanui - were purchased with no additional paint protection which we are addressing with our painting programme. We have a foundation refurbishment and concrete encasement programme to address the condition of these towers.
The condition of the tower grillage foundations below ground level is satisfactory and as a result this work has been deferred and budget moved to FY26.

Poles

As shown in Figure 6.4.3 the overall condition of most subtransmission poles is good (H4 - H5). More than 50% of our 66kV poles are less than 20 years old and therefore are in near new condition. Most of the 33kV poles are older but are also in serviceable condition, with some mainly timber pole age-related deterioration. These are being prioritised for replacement.

Figure 6.4.3 Subtransmission pole condition profile

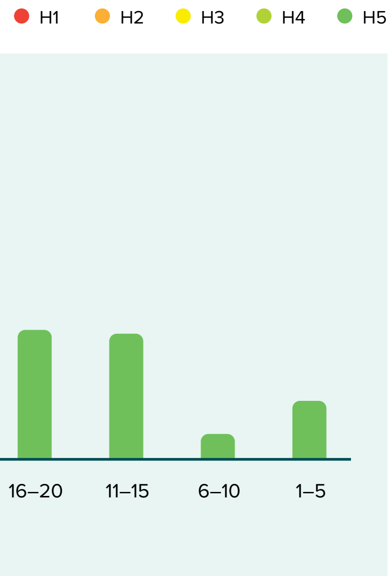


Conductors

The conductors on our overhead subtransmission network are performing well, see Figure 6.4.4. The copper conductors on some 33kV lines are older and showing some signs of wear and is being monitored during routine maintenance. The ACSR conductors on the tower lines are generally in good condition.

We have undertaken detailed testing of some tower line conductors. The Bromley to Heathcote line is in fair condition due to its age, circa 1957, and coastal location. We expect to replace this conductor in FY30 but this may be deferred based on the results of testing in FY28. We will retest these conductors in the interim to assess the rate of deterioration and better determine end of life.

Figure 6.4.4 Subtransmission conductor condition profile

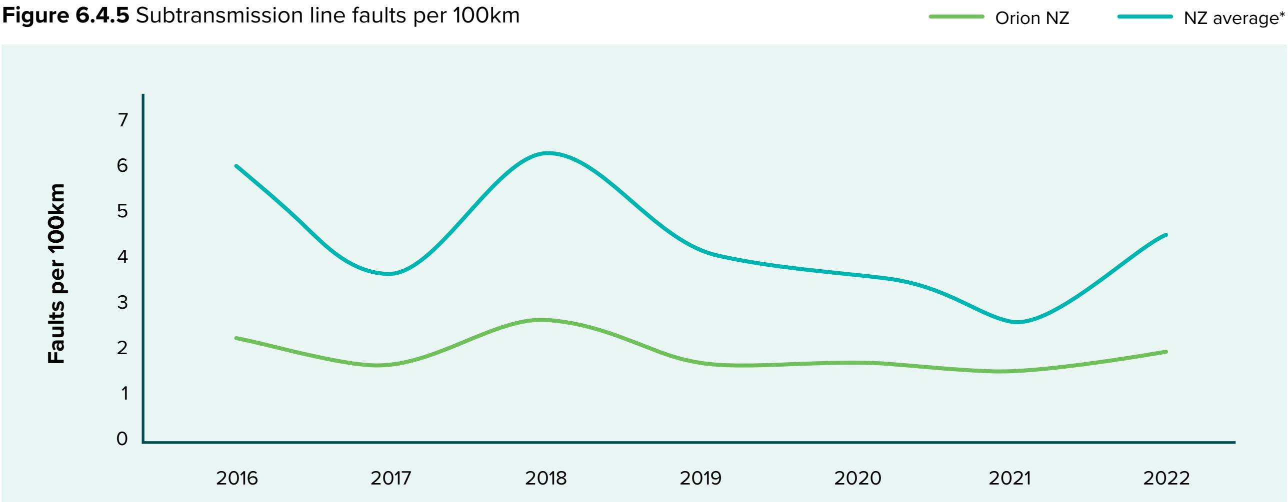


6.4.3.2 Reliability

Our subtransmission lines failure rate has been lower than the industry average for the last seven years. See Figure 6.4.5.

Our subtransmission lines failure rate has been lower than the industry average for the last seven years.

Figure 6.4.5 Subtransmission line faults per 100km



* Source: PwC Electricity Line Business Information Disclosure Compendium 2016-2022

6.4 Overhead lines – subtransmission continued

6.4.3.3 Issues and controls

Table 6.4.3 lists the common causes of overhead line failure and the controls implemented to reduce the likelihood of these failures.

Table 6.4.3 Subtransmission overhead line failure controls

Common failure cause	Known issues	Control measures
Material deterioration	**Timber poles** – lose strength over time **Conductors** – degrade over time, fretting, corrosion, loss of cross-sectional area **Hardware** – binders fatigue and insulators fail over time. Wooden crossarms can fail due to decay/rot. Insulators on wooden crossarms may loosen due to shrinkage or rot	Robust design standards exceed AS/NZS7000-2016 Pole inspection programme and replacement programme Conductor visual inspection Maintenance inspections and re-tightening programme
Third party interference	**Poles** – third party civil works haves the potential to undermine pole foundations **Conductors** – working near power lines can be fatal or lead to serious injury **Conductors** – clearance from the road surface may change over time because of road resurfacing, vehicle contact with poles or conductors sagging too low **Conductor** – trees in contact with conductors can cause damage to the conductor and heighten the risk of electrocution to anyone coming into contact with them or environmental impacts	Reflective markers are attached to all roadside poles in the rural area A consent is required to work within 4m of overhead power lines. Signage and media advertising campaign to raise awareness A High Load consent is required when transporting loads with an overall height of 4.8 meters and higher along the road corridor Conductor crossing height inspected and maintained for compliance (NZECP34) Tree regulations Vegetation control work programme Tree cut notices are sent to tree owners Public information advertising campaign
Environmental conditions	**Timber poles** – ground conditions can contribute to pole structure decay **Conductors** – snow and ice loads on conductor can cause excessive sagging. Lines can clash in high winds leading to conductor damage causing outages **Hardware** – intense vibrations from high wind and weather can cause stress on insulators	Robust design standards exceed AS/NZS7000-2016 Maintenance inspection (including corona camera inspection) and replacement programme Conductor sag is addressed through the line re-tightening programmes and reduces lines clashing

6.4.4 Maintenance plan

Our maintenance activities as listed in Table 6.4.4, are driven by a combination of time-based inspections, maintenance and reliability centred maintenance.

Table 6.4.4 Subtransmission maintenance plan

Maintenance activity	Strategy	Frequency
Pole inspection	Visual inspection of poles and line components for defects	5 years
Conductor testing	Non-destructive x-ray inspection Tower lines have sections of conductor removed and tested	As required
Subtransmission thermographic survey	This technology can detect localised temperature rise on components which can be due to a potential defect	2 years
UV corona camera inspection	This technology can detect excessive discharge on line insulators not normally detectable by other means. It is used to locate faults and assess the general condition of insulators	2 years
Vegetation management	We have a proactive programme in place to trim trees within the corridor stated in the tree regulations. We also consult with land owners with trees that pose a risk to our assets, but are outside the trim corridor. For more information see Section 6.7	2 years
Retightening / refurbishment programme	Retightening of hardware components for pole lines only and the replacement of problematic assets if required; e.g. insulators, dissimilar metal joints, HV fuses, hand binders and crossarms	12 – 18 months from new (retighten); 20 years (retighten); 40 years (refurbish)
Tower painting	Condition assessments are carried out during inspections to identify tower maintenance requirements. We monitor steel condition and we undertake further investigation when issues are highlighted. The ongoing painting programme is designed to protect good steel prior to any issues arising, and the coatings systems are then maintained to optimise this protection	Approx. 30 – 40 years from new, dependent on environmental factors
Tower foundations	Tower foundation maintenance is focused on the concrete encasement programme for the existing grillage foundations, and once this is complete only the above ground interfaces will need ongoing attention	One off
Tower inspection	Visual and lifting inspections provides condition assessment of the tower steel, bolts, attachment points, insulators, hardware and conductors	10 years for visual and lifting inspections 20 years each circuit (10 years each line)

6.4 Overhead lines – subtransmission continued

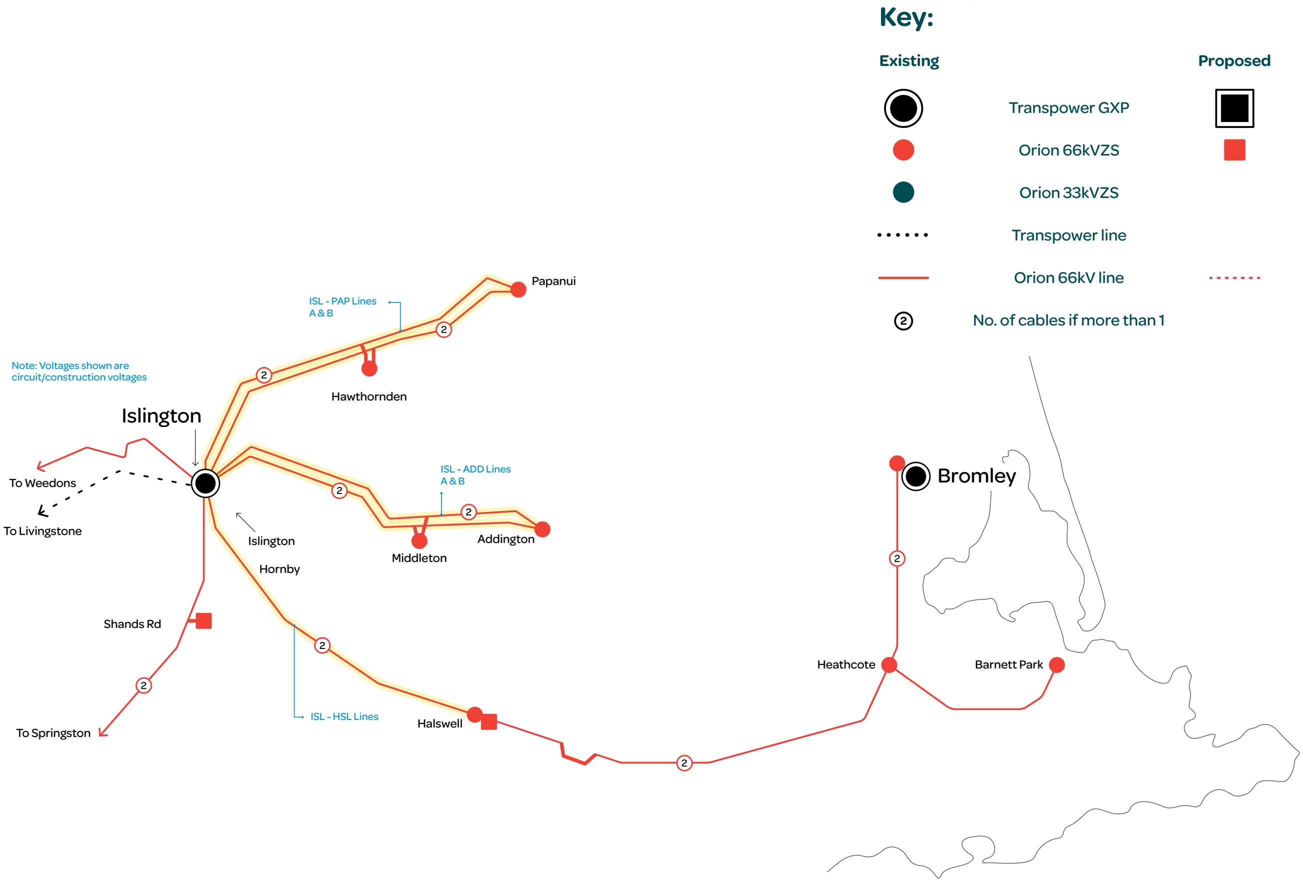
6.4.4.1 Light Detection and Ranging trial

In FY24 we are planning to run a trial of a “Digital Twin”, incorporating Light Detection and Ranging (LiDAR) capture for 5 of our sub transmission tower circuits. We will model these lines to monitor ground clearances and vegetation clearance violations. We will compare our visual condition assessment results, climbing inspection and UAV (Unmanned Aerial Vehicles/drone) inspections. The aim of the trial is to understand if it is cost-effective for us to collect better data for analysis using this method which is safer than asking service providers to climb towers.

The lines we are planning to inspect are highlighted in Figure 6.4.6:

- ISL – ADD (A & B)
- ISL – PAP (A & B)
- ISL – HSL

Figure 6.4.6 LiDAR trial lines



We have chosen the highlighted lines in Figure 6.4.6 for our LiDAR trial for several reasons. We only need to notify 3 sets of landowners regarding our inspection method and the area around these lines enables us to use either UAVs (Unmanned Aerial Vehicles/drones), helicopter or fixed wing aircraft. These lines are also predominantly urban and most likely to be impacted by in-fill housing and land use changes which may affect line clearances. In addition, these lines have the highest load variations, and the LiDAR data will enable us to run maximum line sag scenarios.

If the trial is successful in delivering value, we plan to extend the LiDAR inspection programme to the rest of our tower circuits and sub transmission network. Future plans to use LiDAR to monitor vegetation and ground clearance violations of the 11kV and LV network are in development and will be integrated with any future asset management system.

6.4 Overhead lines – subtransmission continued

A breakdown of subtransmission overhead opex in the Commerce Commission categories is shown in Table 6.4.5. The annual operational expenditure forecast is expected to maintain our current good performance for this asset class.

Table 6.4.5 Subtransmission overhead operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	155	155	155	155	155	155	155	155	155	155	**1,550**
Routine and corrective maintenance and inspections	507	715	1,732	1,679	1,637	1,639	1,637	1,680	1,667	1,680	**14,572**
Asset replacement and renewal	-	-	250	250	250	250	250	250	250	250	**2,000**
Total	**662**	**870**	**2,137**	**2,084**	**2,042**	**2,044**	**2,042**	**2,085**	**2,072**	**2,085**	**18,122**

6.4.5 Replacement plan

Towers

Currently we have not seen any evidence to suggest any of our towers require replacement.

Poles

Our replacement strategy is based on a combination of our risk-based approach to replacement and our new pole inspection programme. We have set an asset class objective to maintain a pole failure rate of less than one in ten thousand poles and reduce our faults per km rate. In setting this objective we considered two scenarios 'do nothing' and 'targeted intervention'.

'Do nothing' involves regular maintenance only, but our chosen solution identifies and prioritises poles based on condition and criticality.

We plan to continue replacing our 33kV poles at a steady rate. The replacement rates have been projected with consideration for cost vs benefit and constraints on resource requirements. We continue to monitor our performance and safety to ensure the optimum levels of replacement are delivered. Based on our projected pole replacement plan, the current and future pole health scenarios are shown in Figure 6.4.7.

We have set an asset class objective to maintain a pole failure rate of less than one in ten thousand poles and reduce our faults per km rate.

6.4 Overhead lines – subtransmission continued

While our asset management approach is risk based historically it has been difficult to produce a visual representation of this. In 2019 the Electricity Engineers Association (EEA) released an asset criticality guide which gives industry-led guidance on how to determine an asset's criticality and provides descriptions and grades of risk. As mentioned in Section 5.6, we have produced a risk matrix for our pole assets fleet based on the EEA Asset Criticality Guide. Figures 6.4.7 and 6.4.8 show the risk matrix profiles and the summarised risk scenarios for our subtransmission poles. They compare our current risk profile, with a counterfactual do nothing, and proposed targeted intervention profiles over the next 10 years. It shows that if we do nothing, there is a significant increase in the risk of pole failures, and that the forecast replacement program is appropriate to manage this risk.

Figure 6.4.7 Subtransmission pole risk matrix

Current matrix

Asset criticality index (columns) / Asset health index (rows)

	C4	C3	C2	C1	Total
H1	0	1	38	0	39
H2	0	17	2	0	19
H3	0	136	610	49	795
H4	0	318	1,178	60	1,556
H5	0	472	2,282	241	2,995
Total	0	944	4,110	350	5,404

Risk grade definitions

R5	Low relative consequence of failure. Tolerating increased failure rates or running asset to failure may be viable strategies
R4	Typical asset in useful life phase. Strategy is to monitor and maintain
R3	Healthy but highly critical assets. Operating context would need to be changed if consequence of failure are to be reduced
R2	Combination of criticality and health indicates elevated risk. Appropriate intervention measures should be scheduled
R1	Combination of high consequences of failure and reduced health indicates high risk. Immediate intervention required

Do nothing matrix by Y10

Asset criticality index (columns) / Asset health index (rows)

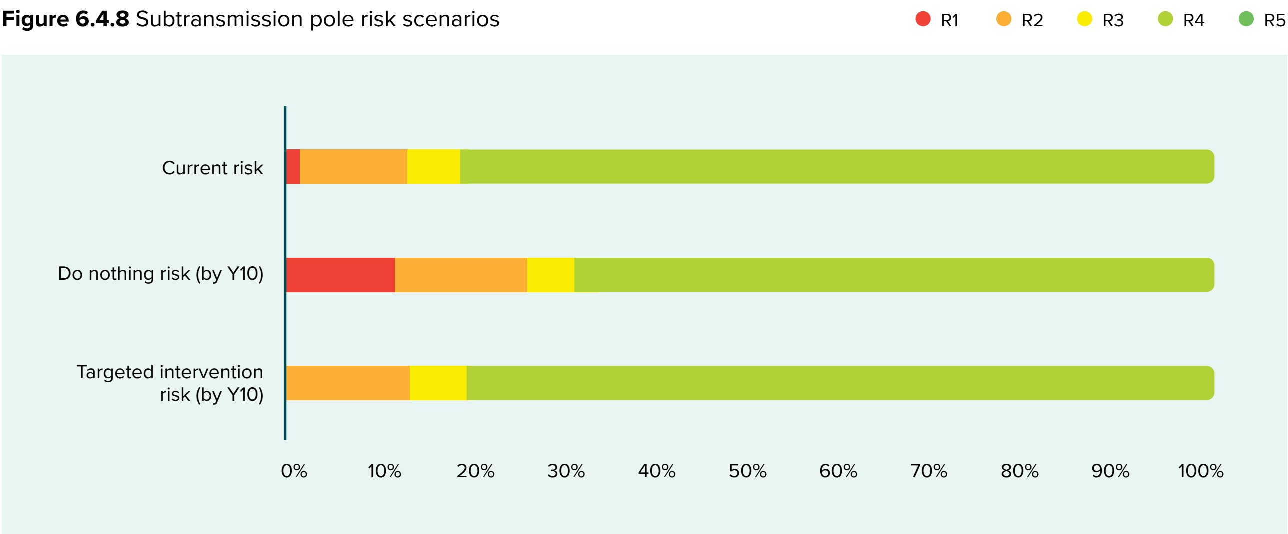
	C4	C3	C2	C1	Total
H1	0	69	482	46	597
H2	0	3	107	3	113
H3	0	255	674	32	961
H4	0	292	1,586	129	2,007
H5	0	325	1,261	140	1,726
Total	0	944	4,110	350	5,404

Targeted intervention matrix by Y10

Asset criticality index (columns) / Asset health index (rows)

	C4	C3	C2	C1	Total
H1	0	0	0	0	0
H2	0	3	105	0	108
H3	0	255	590	0	845
H4	0	291	1,543	123	1,957
H5	0	395	1,872	227	2,494
Total	0	944	4,110	350	5,404

Figure 6.4.8 Subtransmission pole risk scenarios



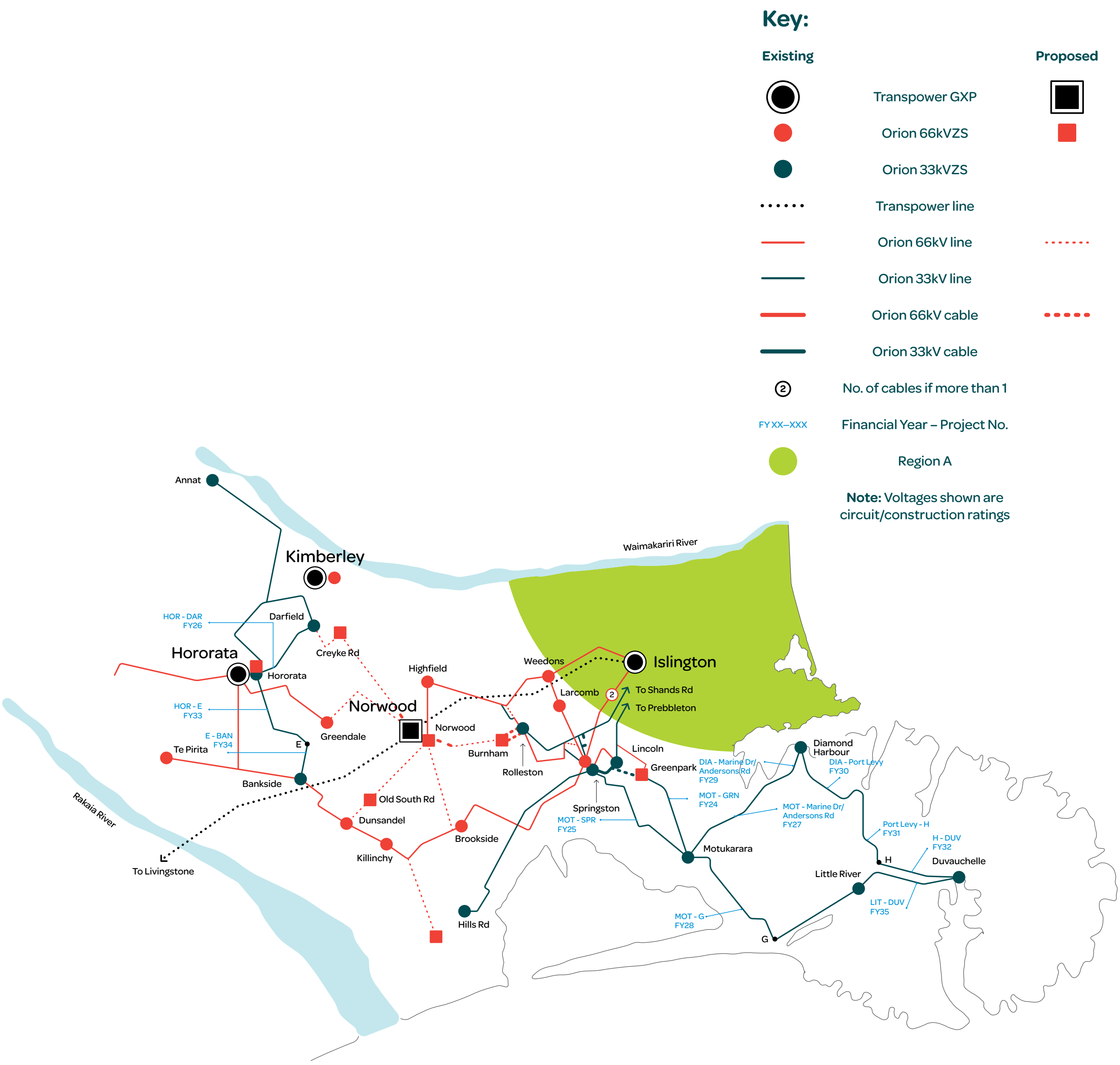
6.4 Overhead lines – subtransmission continued

A significant amount of our 33kV subtransmission on Banks Peninsula is nearing an age when it requires refurbishment and in some cases, upgrades to meet current design standards. The subtransmission on Banks Peninsula is a critical part of our network and supports local communities on the Peninsula such as Diamond Harbour, Little River, Duvauchelle and Akaroa.

The refurbishment work is planned over the next 10 years to efficiently manage resource, budgets, and limit disruption to communities where possible. We will engage with the communities impacted over the next year and maintain engagement throughout the whole project.

For the areas we plan to refurbish over the coming years, see Figure 6.4.9.

Figure 6.4.9 Areas of our 33kV subtransmission lines on Banks Peninsula to be refurbished



Replacement forecast

The 33kV feeders on the Peninsula form a crucial part of the network to support our local communities. These feeders are exposed to the weather elements more than other parts of the network. It is important that we prioritise the maintenance for these feeders. Most of this work is reinsulating the feeder where insulators on the wooden cross arms start to lean over time. Many of the crossarms on these feeders will also be replaced as well as some poles where required. We expect the conductor on most of these feeders will still be in good condition and will continue to provide a reliable service, however some sections may need replacing if significant deterioration is found when completing the reinsulating work.

6.4 Overhead lines – subtransmission continued

Pole top hardware

For economic efficiency crossarms and insulators are replaced or refurbished in conjunction with the pole replacement programme, the line retightening programme and targeted programmes if required.

Conductors

We have tested conductor samples from our Bromley to Heathcote, Islington to Halswell and Heathcote to Barnett Park lines to determine end of life. Our testing confirmed we may need to replace the conductor on our Bromley to Heathcote line. We plan on retesting the Bromley to Heathcote line to measure the rate of deterioration.

The results will inform our replacement strategy but most likely the line will be redesigned in FY27-FY28 and replaced in FY29-FY30.

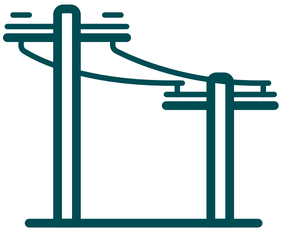
Condition data and work package optimisation for high-risk poles enables us to be more efficient in delivering our target number of pole replacements and maintain a safe and reliable network. Traditionally, historical unit rates have been used to forecast capital expenditure. However, with supply chain issues, and increased safety and traffic management requirements, basing expenditure estimates on historical costs is no longer acceptable. We now use a unit rate based on the most up-to-date cost engineer estimates.

Table 6.4.6 Subtransmission replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Subtransmission	1,129	1,208	1,029	4,294	4,794	5,294	5,794	5,294	6,294	6,294	**41,424**
Total	**1,129**	**1,208**	**1,029**	**4,294**	**4,794**	**5,294**	**5,794**	**5,294**	**6,294**	**6,294**	**41,424**

6.4.5.1 Disposal

All poles are disposed of by our service providers in a manner appropriate to the pole type. A lifecycle analysis carried out in 2020 confirmed recycling of poles for another use is the best outcome – where possible in non-structural community projects. Examples of where our old poles have been re-used include playgrounds and mountain bike tracks. Poles may be recycled, sold as scrap, on sold for non-commercial purposes or dispatched to landfill. Metal materials are disposed of through members of the Scrap Metal Recycling Association of New Zealand (SMRANZ).



Our 11kV distribution overhead system has 3,146km of lines servicing central Canterbury, Banks Peninsula and outer areas of Christchurch city.

6.5 Overhead lines – distribution 11kV

6.5.1 Summary

Our 11kV overhead lines are the workhorse of our distribution network in Region B and outer Christchurch city. Their failures have the potential to negatively affect our safety objectives, and disrupt the lives of the community. We are increasing 11kV lines expenditure over the next 10 years, mainly to obtain better conductor condition information and minimise pole failures, but also to maintain overall reliability and asset condition. The increased expenditure will also allow for adaptation of our network to ensure it is built to withstand climate change.

6.5.2 Asset description

Our 11kV distribution overhead system is 3,100km of lines servicing the rural area of central Canterbury, Banks Peninsula and outer areas of Christchurch city. These lines are supported by 47,500 timber and concrete poles, some of which also support subtransmission and 400V conductors.

Our 11kV lines are supplied from zone substations. Supply is also taken directly at 11kV from the GXPs at Coleridge, Castle Hill and Arthur's Pass. We have 100km of single wire earth return (SWER) lines used to supply power to remote areas on Banks Peninsula. The 11kV system includes lines on private property that serve individual customers.

The 11kV overhead asset class comprises three distinct assets: pole, pole top hardware and conductor.

Poles

The 11kV poles provide support for the 11kV line assets and other classes of network assets, such as pole-mounted transformers, low voltage lines and associated hardware. There are four types of poles used on our network:

- **Timber** – comes in hardwood and softwood. Hardwood has superior strength over softwood poles due to its dense fibre characteristics. The expected life of hardwood poles depends on the timber species, preservative treatments and configuration. Timber poles in areas exposed to harsh environmental conditions have a reduced nominal service life
- **Concrete** – pre-stressed concrete poles which have superior tensile strength compared to precast concrete. We no longer install precast poles on our network
- **Steel** – we have four steel monopoles specifically designed to suit their location and span length. We have installed concrete pile foundations to support these poles
- **Steel pile** – we have 44 steel pile structures to support the hardwood poles in or near riverbeds

Today, we predominantly install timber poles due to their dynamic loading characteristics and sustainability benefits. Table 6.5.1 shows the pole types and quantities installed on our network.

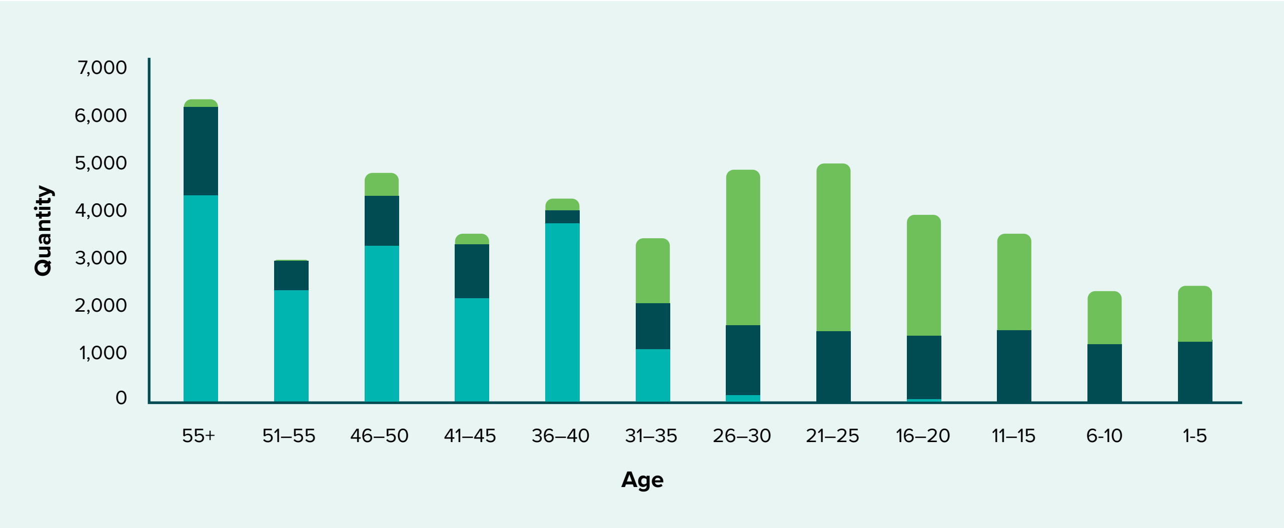
Table 6.5.1 11kV pole quantities by type

Pole type	Quantity
Timber (Hardwood)	14,102
Timber (Softwood)	16,116
Concrete	17,179
Steel pole and piles	48
Total	**47,445**

6.5 Overhead lines – distribution 11kV continued

Figure 6.5.1 age profile shows a transition in the 1990s from concrete poles to timber poles. This change was made based on a combination of lifecycle economics and engineering considerations. It also shows that the majority of our older poles are concrete and steel.

Figure 6.5.1 11kV pole age profile



Pole top hardware

Pole top hardware are components used to support overhead conductors on the pole. This consists of crossarms and braces, insulators, binders and miscellaneous fixings. Crossarms are constructed of either hardwood timber or steel. We use hardwood timber crossarms which have an expected life of 40 years. We have porcelain, glass and polymer insulators installed on our network. We do not have complete records of the ages of these components.

Conductors

A variety of conductor types are used for the 11kV overhead network. The decision as to which conductor type is used is influenced by economic considerations, the asset location, environmental and performance factors. The number of conductor types we use is listed in Table 6.5.2.

They are:

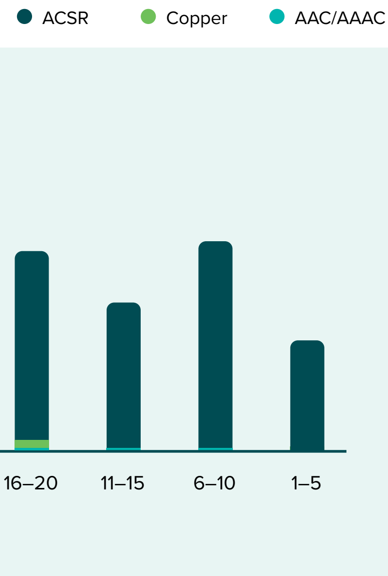
- **HD Copper –** hard drawn stranded copper conductor, which is no longer installed on our 11kV network
- **Aluminium conductor-steel reinforced (ACSR) –** a stranded conductor used extensively on our HV network. This conductor is chosen for its high strength good conductivity and lower cost when compared to copper. It performs well in snow, wind and ice environments
- **Other aluminium –** all Aluminium Conductors (AAC) are made up of stranded aluminium alloy. All Aluminium Alloy Conductors (AAAC) have a better strength to weight ratio than AAC and also offer improved electrical properties and corrosion resistance

Table 6.5.2 11kV conductor quantities by type

Conductor type	Length (km)
HD Copper	272
Aluminium (ACSR)	2,803
Other Aluminium (AAC & AAAC)	58
Total	**3,133**

The age profile in Figure 6.5.2 shows that our conductor population is predominantly ACSR, with hard drawn copper the second most prevalent conductor type.

Figure 6.5.2 11kV conductor age profile



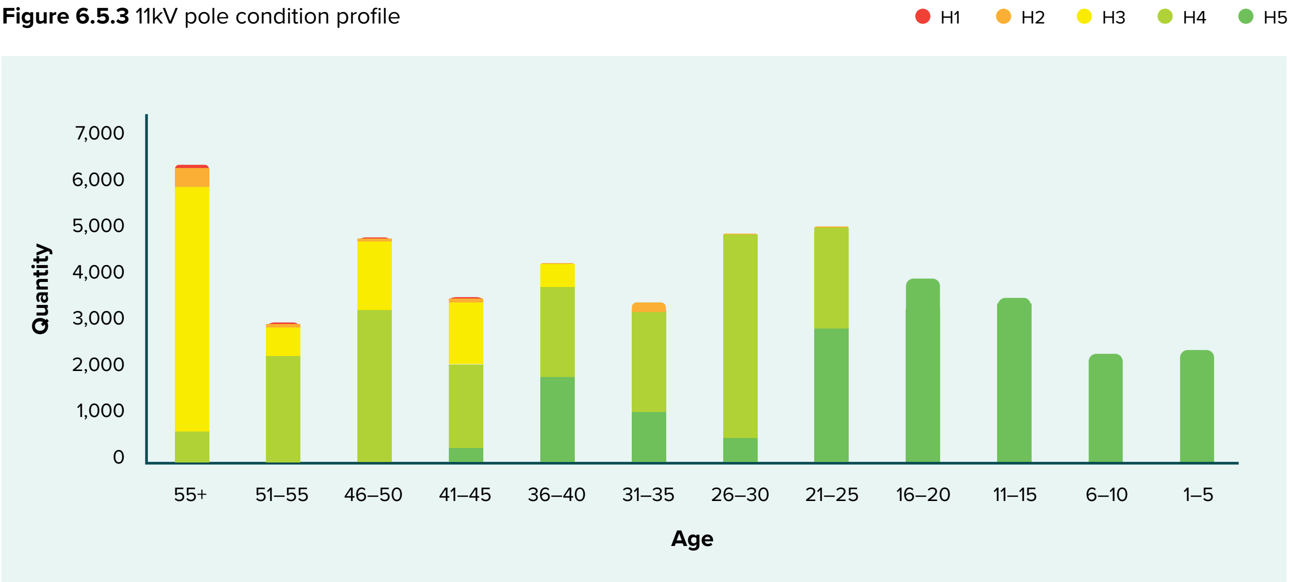
6.5.3 Asset Health

6.5.3.1 Condition

Poles

The condition of our 11kV network has been modelled using CBRM. Figure 6.5.3 shows the current age and condition profile for our overhead 11kV poles. Our poles are predominantly in serviceable condition.

Figure 6.5.3 11kV pole condition profile



Conductor

Across our wide range of conductor types and ages we have identified a number of poorer performing conductor types. A replacement programme has targeted the worst performing (7/16 Cu) conductors. Once that has been completed, we will replace a range of small and end-of-life ACSR conductors.

6.5 Overhead lines – distribution 11kV continued

6.5.3.2 Reliability

Figure 6.5.4 is compiled using information disclosure data. It shows our 11kV lines fault rate per 100km has been higher than the industry average and has also exceeded our target of 18 faults per 100km. The increase in overhead fault rate is due to wildlife climbing onto the power lines, vegetation and lightning strike.

A contributing factor may be warmer weather conditions which caused a mega mast year 2019/2020 creating exceptionally high levels of plant seeds, stimulating higher breeding rates of wildlife such as possums and rats. These conditions are also favourable to faster growth rates for vegetation.

Lightning Strikes

We have seen a significant increase in lightning strikes in recent years particularly in spring and summer with warmer temperatures. These happen predominantly in the rural and Banks Peninsula areas and are sporadic in nature.

Wildlife

Over the last four years we seen an increase of possums coming into contact with our overhead lines. Orion has been installing possum guards on the concrete poles that have significant outage issues. We have also partnered with the Department of Conservation to help eradicate possums in our most affected areas in Banks Peninsula.

Vegetation

Although we have an extensive vegetation management programme some tree species grow faster than our regular tree trimming rounds. We work with land owners to manage their trees. We have also initiated a project to target areas with fast growing vegetation issues.

While the number of faults is increasing, our reliability with regards to SAIDI and SAIFI is improving. This is likely to as a result of our installation of remote line switches on our network that enable us to switch and restore the network faster in response to faults. For more information on vegetation management, see Section 6.7.

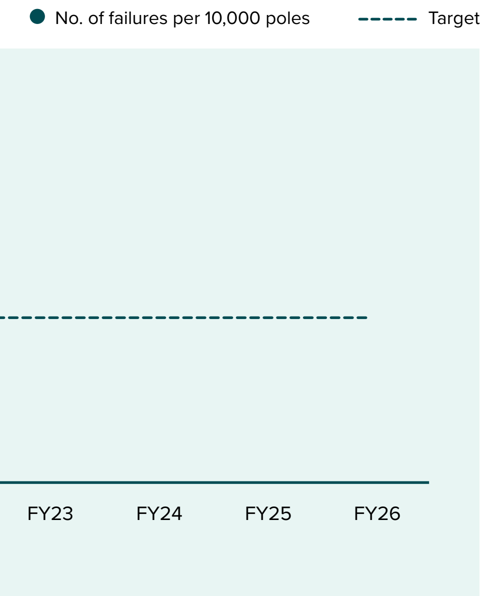
Figure 6.5.4 11kV line faults per 100km

* Source: PwC Electricity Line Business Information Disclosure Compendium 2015-2022

Pole failure rate

To support public safety and network reliability we have established a pole failure rate[1] target of less than one failure per 10,000 of all pole voltage classes combined. In 2016 we established a more robust definition of 'pole failure' along with a renewed approach to identifying and reporting suspect poles. Since taking effect, five years of comparable data has been reviewed under this benchmark. Figure 6.5.5 shows we met our asset class objective for the last five years.

Figure 6.5.5 Pole failure rate (all voltage classes)



[1] "Pole Failure" is where the pole has failed to be self-supporting under normal load conditions and has fallen or is sufficiently unstable that it is posing a risk to people's safety or damage to property. The term does not cover events where a pole has fallen due to an "Assisted Failure", such as impacts from vehicles or trees. It also does not cover "red tag" poles that are replaced immediately when found to be at risk of failure under normal structural loads. We have monitored our poles according to this definition since 2016.

Table 6.5.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 6.5.3 11kV overhead line failure controls

Common failure cause	Known issues	Control measures
Material deterioration	**Pole** – loss of strength over time **Conductor** – degrades over time, fretting, corrosion, loss of cross–sectional area **Hardware** – binders fatigue and insulators fail over time. Wooden crossarms can fail due to decay/rot. Insulators on wooden poles may loosen due to shrinkage	Robust design standards exceed AS/NZS7000–2016 Pole inspection programme and replacement programme Conductor visual inspection Maintenance inspections and re-tightening programme
Environmental conditions	**Pole** – poor ground conditions can contribute to wooden pole structure decay **Conductor** – snow and ice loads on conductor can cause excessive sagging. Lines can clash in high winds leading to conductor damage causing outages **Hardware** – intense vibrations from earthquakes and weather can cause stress on insulators	Robust design standards exceed AS/NZS7000–2016 Maintenance inspection (including corona camera inspection) and replacement programme Conductor sag is addressed through the line re–tightening programmes and reduces lines clashing
Third party interference	**Pole** – third party civil works has the potential to undermine pole foundations	We have a Close Approach consent process and measures for temporary pole stabilisation (NZECP34)
	Vehicles vs poles	Reflective markers are attached to all roadside poles in rural areas
	Conductor – working near power lines can be fatal or lead to severe injury **Conductor** – clearance from the road surface may change over time because of road re-surfacing, vehicle contact with poles or soil disturbances caused by nature **Conductor** – tress in contact with conductors can damage the conductor and heighten the risk of electrocution to anyone coming into contact with them or environmental impacts	A Close Approach Consent is required to work within 4m of overhead power lines Signage and public information advertising campaign to raise awareness A high load consent is required when transporting loads with an overall height of 4.38 metres and higher along the road corridor Conductor height inspected and maintained for compliance (NZECP34) Tree regulations Vegetation control work programme Tree cut notices are sent to tree owners Public information advertising campaign

6.5.4 Maintenance plan

Regular inspections are carried out to ensure the safe and reliable operation of our assets. This supports Orion's asset class objectives to maintain our overhead network performance in balance with risk and cost to meet customer expectations.

We anticipate that fit for purpose maintenance and replacement strategies will need rich data collection to make better asset management decisions. For this reason, we are planning to focus on obtaining accurate condition data of our overhead conductors to assist with future end of life and climate adaptation renewal programme.

Our maintenance activities, as listed in Table 6.5.4, are driven by a combination of time based inspections, and reliability centred maintenance.

Table 6.5.4 11kV overhead maintenance plan

Maintenance activity	Strategy	Frequency
Pole inspection	Detailed inspection of poles and lines including excavation for some types	Five years
UV corona camera inspection	This technology can detect excessive discharge on line insulators not normally detectable by other means. It is used to locate faults and assess the general condition of insulators	Two years
Vegetation management	We have a proactive programme in place to trim trees within the corridor stated in the tree regulations. We also consult with land owners with trees that pose a risk to our assets, but are outside the trim corridor. Refer to Section 6.7 for more information	Two years
Retightening / refurbishment programme	Retightening of hardware components, replacement of problematic assets if required e.g. insulators, dissimilar metal joints, HV fuses, hand binders and crossarms	Initially at 12 – 18 months from new (retighten), then at 20 years (retighten/refurbishment), then again at 40 years (refurbishment)

An annual forecast of 11kV overhead operational expenditure in the Commerce Commission categories is shown in Table 6.5.5.

Table 6.5.5 11kV overhead operational expenditure (real) $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	**12,050**
Routine and corrective maintenance and inspection	2,830	3,315	5,548	5,778	8,631	11,598	12,560	14,563	13,508	15,512	**93,843**
Asset replacement and renewal	-	1,573	2,907	2,240	2,240	2,240	2,240	2,240	2,240	2,240	**20,160**
Total	**4,035**	**6,093**	**9,660**	**9,223**	**12,076**	**15,043**	**16,005**	**18,008**	**16,953**	**18,957**	**126,053**

6.5.5 Replacement plan

Poles

As a pole's age increases, so too does its probability of failure, and defects and condition driven failures are likely to increase. To meet our asset class objective to maintain a pole failure rate of less than one in 10,000 poles and to reduce our faults per km rate we have considered these options:

- **Targeted intervention –** the chosen solution which identifies and prioritises poles based on condition and criticality
- **Do nothing –** regular maintenance only, but does not prevent material deterioration in condition
- **Underground conversion –** an option that is normally uneconomical

The optimised replacement approach options are shown in Figure 6.5.6 and Figure 6.5.7.

As mentioned in Section 5.6, we have produced a risk matrix for our poles fleet based on the EEA Asset Criticality Guide. Below is an example of our current, do nothing and targeted intervention risk profile over the next 10 years. It shows that if we do nothing it poses a significant risk to us in the future where we would struggle to avoid catastrophic failures of poles.

Figure 6.5.6 11kV pole risk matrix

Current matrix

Asset health index \ Asset criticality index	C4	C3	C2	C1	Total
H1	1	417	20	1	439
H2	0	243	12	1	256
H3	149	8,392	541	14	9,096
H4	254	16,948	778	21	18,001
H5	233	17,994	1,300	32	19,559
Total	637	43,994	2,651	69	47,351*

Risk grade definitions

Grade	Definition
R5	Low relative consequence of failure. Tolerating increased failure rates or running asset to failure may be viable strategies
R4	Typical asset in useful life phase. Strategy is to monitor and maintain
R3	Healthy but highly critical assets. Operating context would need to be changed if consequence of failure are to be reduced
R2	Combination of criticality and health indicates elevated risk. Appropriate intervention measures should be scheduled
R1	Combination of high consequences of failure and reduced health indicates high risk. Immediate intervention required

Do nothing matrix by Y10

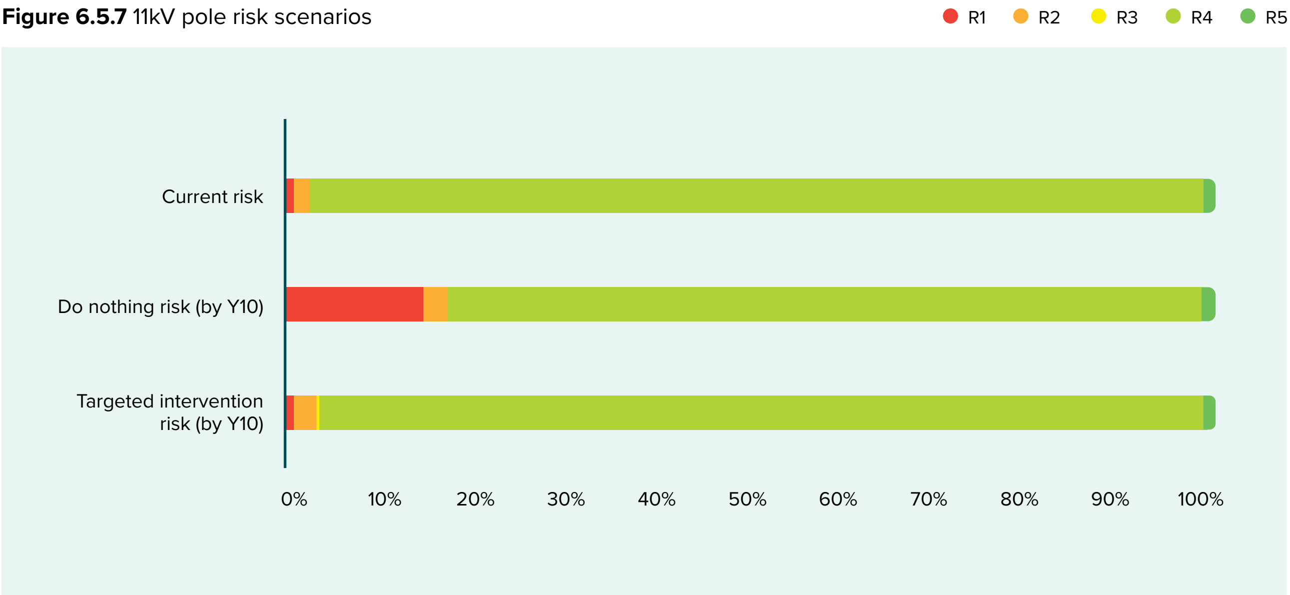
Asset health index \ Asset criticality index	C4	C3	C2	C1	Total
H1	140	6,478	499	15	7,132
H2	10	770	31	0	811
H3	145	12,752	463	12	13,372
H4	284	16,663	1,109	33	18,089
H5	58	7,331	549	9	7,947
Total	637	43,994	2,651	69	47,351*

Targeted intervention matrix by Y10

Asset health index \ Asset criticality index	C4	C3	C2	C1	Total
H1	11	371	6	1	389
H2	10	687	30	0	727
H3	145	12,699	463	12	13,319
H4	284	16,607	1,096	30	18,017
H5	187	13,630	1,056	26	14,899
Total	637	43,994	2,651	69	47,351*

* Numbers may vary slightly from Table 6.5.1 depending on the timing of data extracts.

Figure 6.5.7 11kV pole risk scenarios



We believe our targeted replacement plan is appropriate as it achieves our asset class objective to maintain a safe, reliable, resilient system. While the targeted intervention risk in Figure 6.5.7 shows some poles as orange (R2) or "high" risk the overall risk profile remains largely the same.

This replacement programme, in conjunction with subtransmission and LV pole replacement supports our asset class objective to maintain less than one in 10,000 failure.

As a result, we are planning a steady increase in the replacement of our mainly timber poles, as shown in Figure 6.5.8.

Figure 6.5.8 11kV pole replacement plan

Pole inspections

Orion's biggest asset risk in terms of the reliability of our network and public safety lies in our overhead network. An overhead network is exposed, more susceptible to unfavourable weather conditions, and is in the midst of our community.

Orion takes the risk of pole failure very seriously and we track and monitor rare pole failures via managed reports and dashboards. Pole inspections are critical to reducing the risk of pole failures and allow us to make informed decisions about what poles to replace before they have the potential to fail. To ensure we are making the most accurate data driven investment decisions in FY21 we reviewed our inspection process to identify any gaps and areas for improvement.

Our review determined that the existing visual inspection process had three fundamental improvement opportunities:

- was not repeatable
- did not accurately capture our most common failure mode for a wooden pole which is decay below ground level
- did not provide us with enough detail about a pole's condition or its defects

The most significant change we made to our inspection process was to introduce the excavation of Orion owned poles that are at higher risk of below ground rot. These are untreated hardwood and softwood larch poles of which there are around 12,700 in our network. Under the new process, we excavate to a maximum depth of 300mm in sealed pavement, asphalt, and grass and inspect the underground conditions of these poles. If needed, reinstatement follows promptly.

Since we began excavations in April 2021, Orion has significantly reduced the number of high risk poles on our network. As part of the new process, we tailored a digital field capture platform to record our pole inspection data and send it back to our engineers for assessment. This platform enables our service providers in the field to capture photos and make annotations to the photos which helps with decision making when assessing defects and poles for replacement. The photos will also provide us with an historic reference to measure deterioration rates the next time a pole is inspected.

Since we began excavations in April 2021, Orion has significantly reduced the number of high risk poles on our network.

In FY23 we decided to take a risk-based approach to our inspections and have focused our efforts on inspecting all untreated hardwood and softwood larch poles. As a result of the new inspection programme, we have been able to find and replace high risk poles with more urgency. At risk poles are identified by a two-coloured tag system:

Orange tag – to be replaced within three months

Red tag – for immediate replacement

Our accelerated pole inspection process has resulted in planned pole replacements being deferred in favour of the more immediate risk posed by the red and orange tagged poles.

The new inspection process is enabling Orion to better plan our replacement programme more efficiently and effectively, based on a deeper understanding of our pole fleet condition.

The new pole inspection process gives Orion better quality of data but requires pole inspectors to take more time per pole inspection due to excavation required at the base of some poles. This has led to an increase of expenditure for pole inspections. We expect that the long-term benefits will enable Orion to make more effective forecasts and optimal planning decisions for pole replacement which will reduce the need for some reactive works and reduce unnecessary costs.

Climate change adaption

Climate change is likely to have a significant impact on our overhead network if we are not able to mitigate its effects. As part of Orion's asset management strategy, we are starting to build an adaptation plan to manage the physical risks climate change may pose to our network. The overhead network is exposed to the elements and has the greatest potential to be affected by the physical risks of climate change. Orion's Climate change Opportunities and Risks for Orionreport identifies Orion's approach to climate change overall.

As Orion becomes more mature in understanding our risks in relation to climate change we will factor these into our strategic decisions for the future maintenance and replacement work across our network.

Pole top hardware

For economic efficiency, crossarms and insulators are replaced or refurbished in conjunction with the pole replacement programme, the line retightening programme and targeted programmes if required. Recently we have been focusing on reliability improvement for rural townships by targeting feeders through a combination of insulator and crossarm replacements and installation of automated line switches.

Conductor

We aim for asset standardisation where possible, so unless demand or capacity reasons dictate otherwise, the standard like-for-like when replacing conductors will be Dog or Flounder ACSR.

Overhead to underground conversion

An option to consider for replacing end of life 11kV overhead lines is the possibility of converting to underground cables. As the cost per meter is significantly lower for overhead lines it is normally not economically justifiable to do so. However we are considering a programme from FY27 onwards to convert approximately 4km of overhead lines to underground in the western suburbs of Christchurch per year. The drivers for this replacement are a mixture of condition based replacement, safety, resilience and reliability improvement. A business case including cost benefit analysis will be completed to assess the viability of this project.

A breakdown of 11kV overhead capex in the Commerce Commission categories is shown in Table 6.5.6.

The capex expenditure forecast is expected to contribute to improving our asset class reliability performance while maintaining our pole failure rate to less than one failure per 10,000 poles.

As an outcome of reviewing our pole replacement processes, we identified that replacing all the poles we needed to in a particular area, irrespective of the voltage of the lines, was more efficient than our previous approach of focusing on one asset class at a time.

As a result, the replacement capex for LV poles is combined with 11kV poles and the total capex is shown in Table 6.5.6.

The capex expenditure forecast is expected to contribute to improving our asset class reliability performance while maintaining our pole failure rate to less than one failure per 10,000 poles.

The capital expenditure for this asset class also includes the installation cost for replacing end of life Air Break Isolators (ABI). The material cost is captured in section 6.11 Switchgear.

Condition data and work package optimisation for high-risk poles enables us to be more efficient in delivering our target number of poles and maintain a safe and reliable network. Traditionally, historical unit rates have been used to forecast capital expenditure. However, with supply chain issues, and increased safety and traffic management requirements, basing expenditure estimates on historical costs is no longer acceptable. We now use a unit rate based on the most up-to-date cost engineer estimates.

We know the impacts of climate change will require significant investment to ensure current levels of service are maintained. There will be more emphasis on mitigating the effects of increased wind speeds and temperature variations when replacement decisions are required. Additional expenditure has been allowed from FY28 to develop mitigation measures for climate adaptation.

Table 6.5.6 11kV overhead replacement capital expenditure (real) $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Distribution & LV Lines	12,030	15,930	20,920	31,350	32,670	37,470	35,450	37,150	37,150	38,150	**298,270**
Distribution switchgear	390	390	910	910	540	540	520	520	520	520	**5,760**
Total	**12,420**	**16,320**	**21,830**	**32,260**	**33,210**	**38,010**	**35,970**	**37,670**	**37,670**	**38,670**	**304,030**

6.5.5.1 Disposal

See section 6.4.5.1.

Our low voltage 400V distribution overhead network is 2,345km of lines mainly within Region A, delivering power from the street to customer's premises.

6.6 Overhead lines – distribution 400V

6.6.1 Summary

Our low voltage 400V distribution overhead network is 2,345km of lines mainly within Region A, delivering power from the street to customer's premises. The lines are supported by timber, concrete and steel poles. To counteract our aging pole population and maintain our performance we are increasing the pole replacement rate and expenditure over the AMP period.

6.6.2 Asset description

The 400V overhead asset comprises three distinct components; poles, pole top hardware and conductors.

Poles

There are three types of poles on our LV network:

- **Timber – hardwood and softwood** – hardwood has superior strength over softwood poles due to its dense fibre characteristics. The nominal service life of hardwood poles depends on the timber species, preservative treatments and configuration. Timber poles in areas exposed to harsh environmental conditions have a reduced nominal service life.
- **Concrete – pre-stressed concrete** – have superior tensile strength compared to precast concrete. We no longer install precast poles on our network.
- **Steel poles** – we have three steel monopoles specifically designed to suit their location and span length.

Many of our older timber poles have estimated ages as no install date or manufacture date was recorded or available circa pre-2000. The new pole inspection process introduced in FY22 will address this within a five year period. Table 6.6.1 shows the pole type and quantities on our network.

Table 6.6.1 400V pole quantities by type

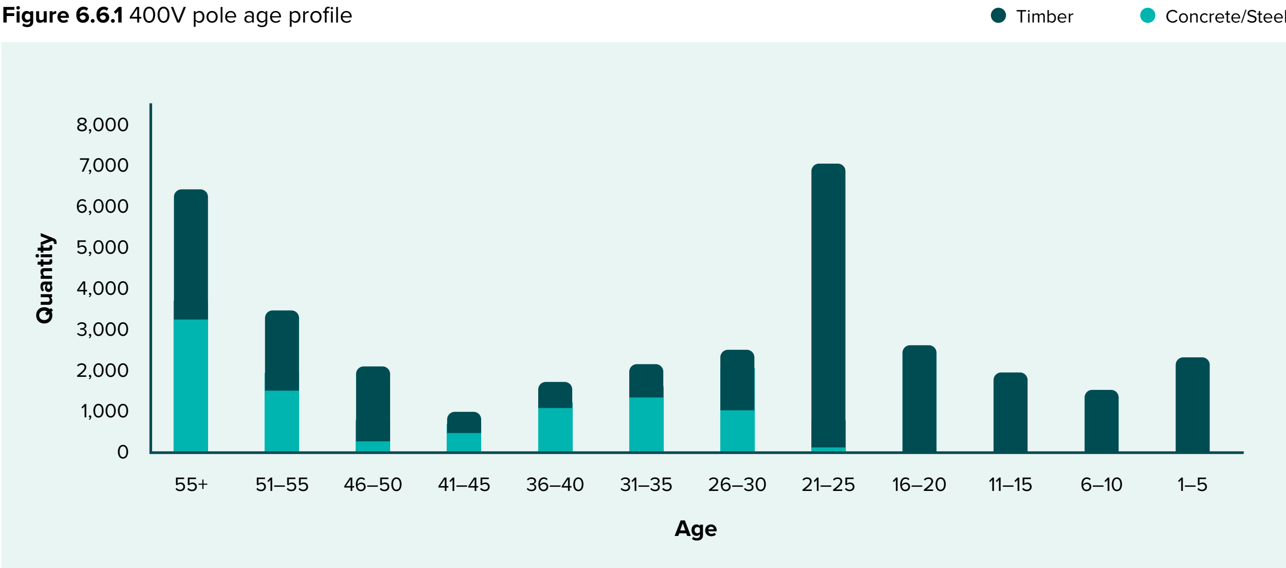
Pole type	Quantity
Timber (hardwood)	10,516
Timber (softwood)	15,122
Concrete	8,992
Steel	3
Total	**34,633**

6.6 Overhead lines – distribution 400V continued

The profile in Figure 6.6.1 shows that our older poles are a mix of timber and concrete types. The age profile shows a transition in the 1990s from concrete pole types to timber pole types. This change was made based on a combination of lifecycle economics and engineering considerations.

The age profile also shows a large population of poles aged 16-20 years, which replaced existing poles when a telecommunications network was installed on our poles.

Figure 6.6.1 400V pole age profile



Pole top hardware

Pole top hardware are components used to support the overhead conductor on the pole. This consists of crossarms and braces, insulators, binders and miscellaneous fixings. We use hardwood timber crossarms which have a nominal asset life of 40 years. We have porcelain insulators installed on our network. We collect pole top hardware data on condition and record the age and type for new insulators.

Conductor

We use a variety of mainly covered conductor types for the LV overhead network. The conductor type chosen is influenced by economic considerations, asset location, environmental and performance factors. The different conductor categories are listed in Table 6.6.2.

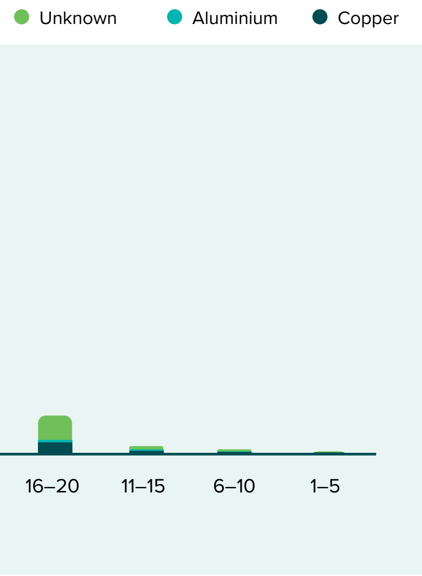
Table 6.6.2 400V conductor quantities by type

Conductor type	Length (km)
Copper (Cu)	793
Aluminium (Al)	148
Unknown	507
Streetlighting (Cu)	896
Total	**2,344***

* Total figure excludes adjustment for road crossings and back section lines.

The age profile in Figure 6.6.2 shows that the majority of our conductors are greater than 40 years old. Our conductor population is predominantly copper, with a large proportion where the type is unknown. Our operators are tasked with identifying the unknown conductor where possible. Only a relatively small proportion are recorded as aluminium.

Figure 6.6.2 400V conductor age profile



6.6.3 Asset health

6.6.3.1 Condition

Poles

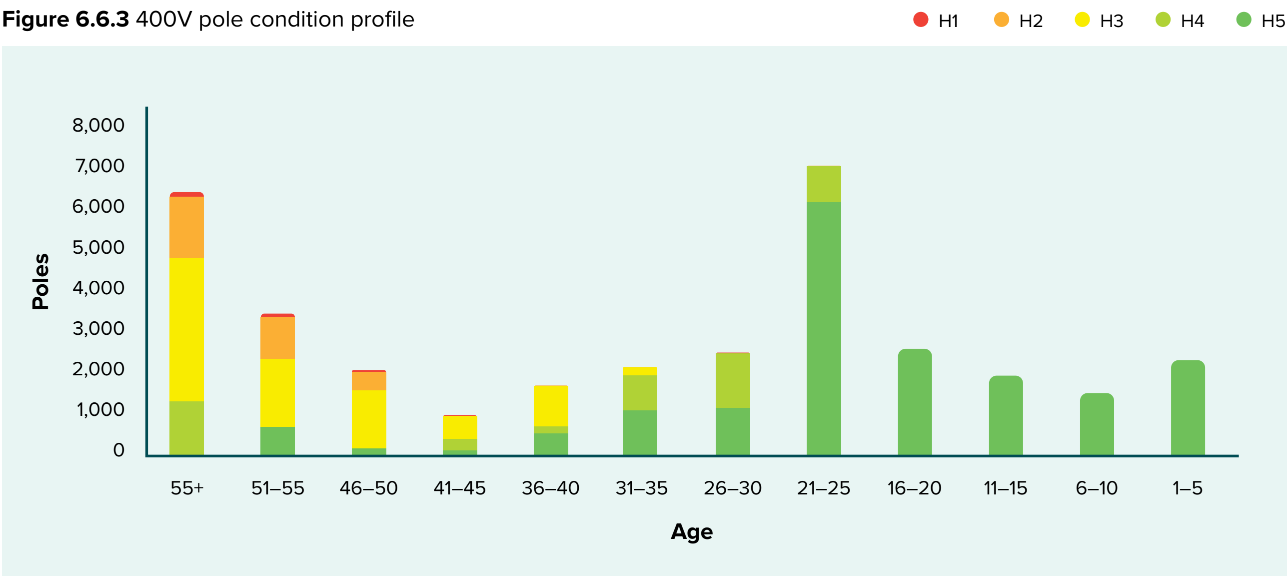
The condition of the low voltage poles has been modelled using the process of CBRM. Figure 6.6.3 shows the condition profile for our overhead LV poles. It can be seen that the pole population is predominantly in serviceable condition, with a smaller amount approaching end of life.

Conductors

Recent modelling of our LV networks has indicated that some conductor spans are operating above rated capacity. Consequently, we have allocated additional budget for upgrading network in these areas to relieve constraints. See Section 6.6.2.2 for details.

Low voltage conductors are predominantly PVC covered with typically shorter spans and tensions of about 5% of Conductor Breaking Load.

Figure 6.6.3 400V pole condition profile



6.6.3.2 Reliability

We are not required to record SAIDI or SAIFI for our LV network. However, to ensure prudent asset management we collect performance data on our LV system. The level of defective equipment has been trending downwards over the last four years. We have also improved our data analysis to separate weather and vegetation events down to their root causes.

Historically some events categorised as weather may have been vegetation related. We will continue to improve the distinction between weather and vegetation related faults to identify areas with vegetation issues to be addressed. Third party related incidents are slowly trending upwards. The majority of these are due to contractor vehicles and excavators coming into contact with overhead lines.

6.6.3.3 Issues and controls

The controls for reducing the likelihood of failure for 400V overhead asset is the same as 11kV overhead assets, see Table 6.5.3.

6.6.4 Maintenance plan

Regular inspections are carried out to ensure safe and reliable operation of our assets. Our maintenance activities are driven by a combination of time based inspections and reliability centred maintenance.

An annual forecast of 400V overhead operational expenditure in the Commerce Commission categories is shown in Table 6.6.3.

We will continue to improve the distinction between weather and vegetation related faults to identify areas with vegetation issues to be addressed.

Table 6.6.3 400V overhead operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	**10,000**
Routine and corrective maintenance and inspection	1,876	2,077	3,288	4,455	4,455	2,955	3,455	3,455	4,955	4,455	**35,426**
Total	**2,876**	**3,077**	**4,288**	**5,455**	**5,455**	**3,955**	**4,455**	**4,455**	**5,955**	**5,455**	**45,426**

6.6.5 Replacement plan

Poles

In recent times our replacement rate for LV poles has been moderately low. This was in part due to our large investment in the replacement of poles in 2000 and 2001 which brought the condition of our poles up to a very good level. The buffer that this created has now reduced. We plan to increase our replacement rate to maintain the health and failure rate of our LV poles.

As mentioned in Section 5.6, we have produced a risk matrix for our poles fleet based on the EEA Asset Criticality Guide. Below is an example of our current, do nothing and targeted intervention risk profile over the next 10 years. It shows that if we do nothing it poses a significant risk to us in the future where we would struggle to avoid catastrophic failures of poles.

Figure 6.6.4 400V pole risk matrix

Current matrix

Asset health index	Asset criticality index C4	C3	C2	C1	Total
H1	28	1,184	21	0	1,233
H2	15	148	3	0	166
H3	112	7,878	53	0	8,043
H4	36	5,558	49	0	5,643
H5	209	19,066	218	0	19,493
Total	400	33,834	344	0	34,578*

Risk grade definitions

Grade	Definition
R5	Low relative consequence of failure. Tolerating increased failure rates or running asset to failure may be viable strategies
R4	Typical asset in useful life phase. Strategy is to monitor and maintain
R3	Healthy but highly critical assets. Operating context would need to be changed if consequence of failure are to be reduced
R2	Combination of criticality and health indicates elevated risk. Appropriate intervention measures should be scheduled
R1	Combination of high consequences of failure and reduced health indicates high risk. Immediate intervention required

Do nothing matrix by Y10

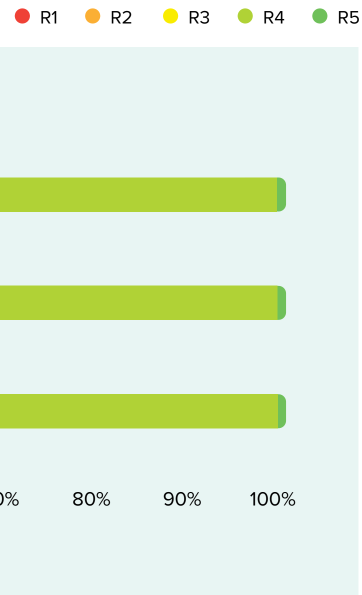
Asset health index	Asset criticality index C4	C3	C2	C1	Total
H1	44	1,695	28	0	1,767
H2	99	5,659	35	0	5,793
H3	15	3,541	24	0	3,580
H4	124	13,158	189	0	13,471
H5	118	9,781	68	0	9,967
Total	400	33,834	344	0	34,578*

Targeted intervention matrix by Y10

Asset health index	Asset criticality index C4	C3	C2	C1	Total
H1	19	802	13	0	834
H2	15	136	3	0	154
H3	112	7,877	53	0	8,042
H4	36	5,558	49	0	5,643
H5	218	19,461	226	0	19,905
Total	400	33,843	344	0	34,578*

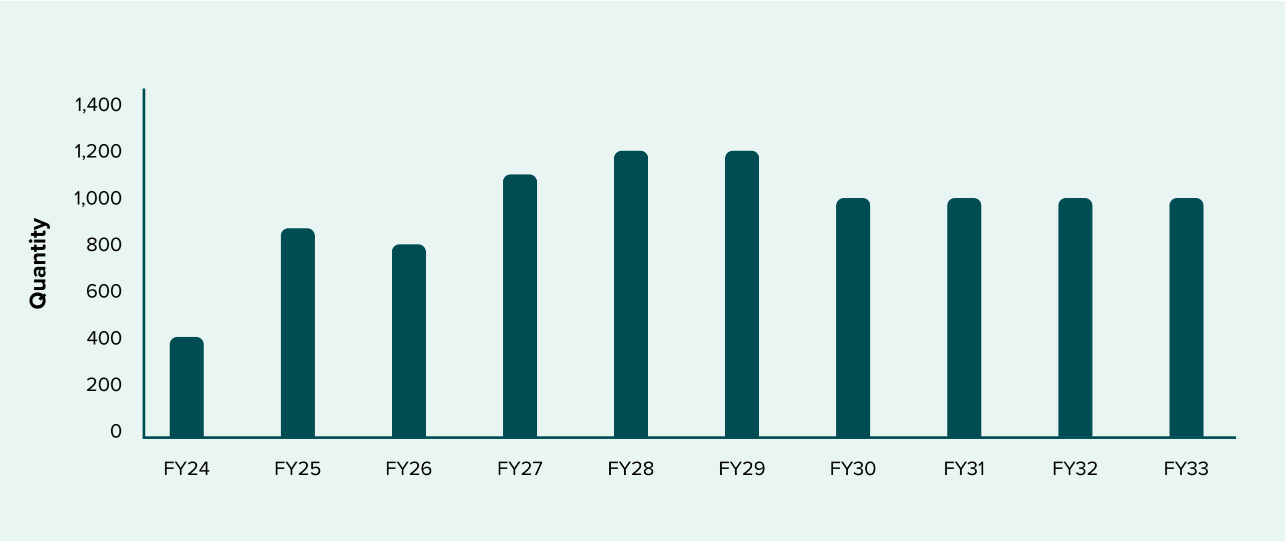
* Numbers may vary slightly from Table 6.6.1 depending on the timing of data extracts.

Figure 6.6.5 400V pole risk scenarios



As a result, we are planning a steady increase in replacement of our mainly timber poles as shown in Figure 6.6.6. This steady increase is necessary to allow time for our service providers to resource appropriately for the work programme.

Figure 6.6.6 400V pole replacement plan



6.6 Overhead lines – distribution 400V continued

Pole top hardware
For economic efficiency crossarms and insulators are replaced in conjunction with the pole replacement programme, the line retightening programme or targeted programmes if required.

Conductor
We do not have a proactive scheduled replacement plan for LV conductor. Any isolated sections requiring repairs or replacement are repaired or replaced under emergency maintenance or non-scheduled maintenance.

Overhead to underground conversion
An option to consider for replacing end of life overhead lines is the possibility of converting to underground cables. As the construction cost for overhead lines is significantly lower than that for undergrounding it is normally not economically justifiable to do so. Most underground conversions are driven and partially funded by third parties such as councils, developers or roading authorities.

Table 6.6.4 shows the replacement expenditure in the Commerce Commission categories.

As mentioned in Section 6.5, the pole replacement budget for this asset class has been included in the 11kV overhead capex.

Condition data and work package optimisation for high-risk poles enables us to be more efficient in delivering our target number of poles and maintain a safe and reliable network. Traditionally, historical unit rates have been used to forecast capital expenditure. However, with supply chain issues, and increased safety and traffic management requirements, basing expenditure estimates on historical costs is no longer acceptable. We now use a unit rate based on the most up-to-date cost engineer estimates.

As mentioned in section 6.5.5, additional expenditure has been allowed from FY29 to implement mitigation measures for climate adaptation on the LV overhead network.

Table 6.6.4 400V overhead replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Distribution & LV Lines	-	300	579	3,510	3,750	13,000	12,250	17,500	21,750	21,000	**93,629**
Other network assets	70	70	70	70	70	70	70	70	70	70	**700**
Other reliability, safety and environment	221	221	221	221	221	221	221	221	221	221	**2,210**
Total	**291**	**591**	**870**	**3,791**	**4,041**	**13,291**	**12,541**	**17,791**	**22,041**	**21,291**	**96,539**

6.6.5.1 Disposal

A lifecycle analysis carried out in 2020 confirmed recycling of poles for another use is the best outcome – where possible in non-structural community projects. Examples of where our old poles have been re-used include playgrounds and mountain bike tracks. Poles may be recycled, sold as scrap, on sold for non-commercial purposes or dispatched to landfill or through members of the Scrap Metal Recycling Association of New Zealand (SMRANZ).

Our vegetation management programme varies slightly to address the different risks associated with voltage levels, type of customers and the challenges of different geographic areas.

6.7 Vegetation management

6.7.1 Summary

At Orion, we are responsible for keeping our network safe and reliable. Under our annual vegetation trimming programme we are permitted to cut trees inside specific zones which are stipulated in the Tree Regulations. However, most of our network faults are due to vegetation outside these zones and which are often out of Orion's control. In 2020, we reviewed our strategy to improve the reliability outcomes for our customers. We introduced a new programme to address vegetation outside of these specified zones – vegetation that poses a significant risk to network safety and reliability. The programme involves Orion working with vegetation owners to remove or lower the risk that they pose to the network. To increase the efficiency and targeting of our vegetation management, we have also implemented electronic platforms to manage programme data collection, reporting and the accountability of our service providers.

Our strategy also includes notifying tree owners if their trees are a potential hazard and conducting public information advertising campaigns. We continue to proactively work with landowners to educate them on the importance of vegetation management around the power network and identify and remove vegetation that is at risk of impacting the network both inside and outside the Notice Zone.

Vegetation has the potential to cause significant damage, outages, and safety risks for our people and the community. These risks will only be increased because of climate change. We recognise prevention is better than cure and have increased our investment in vegetation management. This investment reflects recent changes to traffic management requirements and safety regulation which have led to increases in our costs. It also reflects our heightened focus on managing vegetation in problematic areas to eliminate the risks where possible.

6.7.2 Impact of vegetation on our network

Orion's network has 6,000km of overhead lines that are more susceptible to the risks posed by vegetation growth. Many of these lines run parallel to property fence lines and in rural areas, they are often lined with hedges and trees for shelter belts. These hedges and trees, along with other vegetation encroaching on the power network pose significant risks to our overhead line assets and our service providers and the public who are near them. Without regular vegetation maintenance trees and hedges begin to encroach on the overhead network and can cause power outages, damage, injury and fires.

Considering the impacts of climate change on weather patterns, we expect the current level of vegetation management will not be adequate for future risks.

In some cases, outages caused by tree colliding with our lines can cause lengthy outages, with widespread impact on communities.

We endeavour to identify and remove trees/vegetation that is at risk of impacting the network both within and outside of the Notice Zone as set out in the Tree Regulations. Our vegetation management programme varies slightly to address the different risks associated with voltage levels, type of customers and the challenges of different geographic areas.

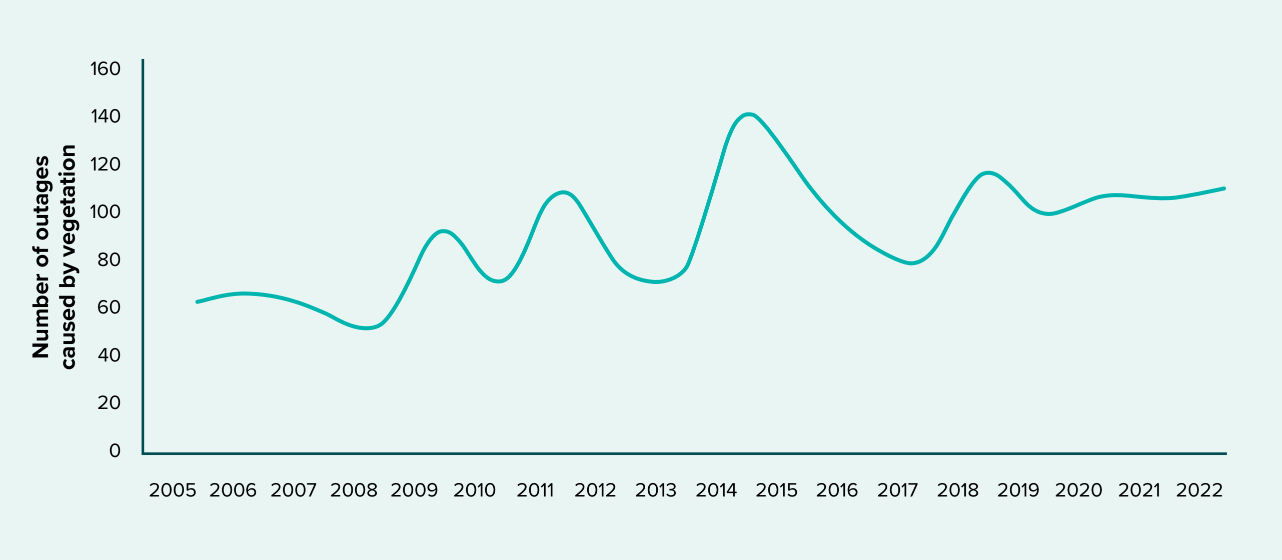
6.7.3 Reliability

Vegetation near the overhead network can have a significant impact on the network's reliability for customers. Risks highlighted as a part of the Orion Climate Change Opportunities and Risks report indicate the growth rates for vegetation are likely to increase due to warmer and wetter conditions because of climate change. The report also indicates an increase in the frequency of severe weather events and higher wind speeds. Considering the impacts of climate change on weather patterns, we expect the current level of vegetation management will not be adequate for future risks.

6.7.4 Issues and controls

The number of outages caused by vegetation has continued to trend upward despite our increasing investment in our vegetation programme, see Figure 6.7.1. Many of these outages are caused by vegetation outside of the cut zones and this has prompted our decision to take a proactive approach to minimise or eliminate the vegetation outside these zones that could have an impact on the network.

Figure 6.7.1 Number of outages caused by vegetation



6.7.5 Maintenance plan

Orion's overhead HV network has significantly higher risk levels than our LV network. To ensure we maintain acceptable performance of the HV network, in conjunction with an inspection/notice regime, we cut pre-existing vegetation around our HV network on a two-yearly basis. We also undertake inspections on the HV network in alternate years to the programmed cut, to address vegetation that grows within the regulatory notice regime. This inspection programme identifies trees that may cause a significant risk to the network due to branches or trees falling from outside of the notice regime.

We have several programmes aimed at meeting our responsibilities as under the Tree Regulations and to minimise risks. These include:

- inspection of vegetation around the network and appropriate notification to vegetation owners
- safety cuts around our LV and HV network
- targeted negotiations for the management of high-risk vegetation
- communication with land and vegetation owners to outline responsibilities and possible low-impact planting
- communication with vegetation contractors regarding the above and also safe working practices

To deliver our tree management programme, we employ the services of competent, experienced authorised service providers who have formal consent and approval to perform work near Orion's network. These are arborists who are familiar with the Orion requirements and can perform their work with minimal disruption to the community. All work is performed in accordance with the tree regulations and Orion's Technical Specification NW72.24.01 – Vegetation Work Adjacent to Overhead Lines. Orion also brings the potential electrical hazards that may exist for themselves, the general public, property and equipment to the attention of landowners, contractors and others working on trees/vegetation in proximity to the electricity distribution network.

Examples of tree/vegetation activities may include, but are not limited to, tree and hedge trimming, forestry, harvesting operations, mobile plant and equipment, loading and transport, land clearance, aerial spraying, silviculture, and helicopter harvest operations. It is envisaged that, over time, this combined approach will identify any potential hazards and significantly remove the issues that problematic trees/vegetation can cause to the network and minimise unscheduled power outages.

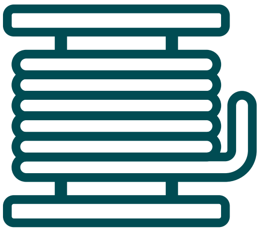
6.7 Vegetation management continued

Since vegetation has the potential to cause significant damage, outages and safety risks to our network our people and the community we have prioritised investment in vegetation management. This investment captures recent changes to traffic management and safety regulation that have led to an increase in costs, and our heightened focus on problematic areas of the network to eliminate the risks where possible.

Table 6.7.1 Vegetation management operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
LV vegetation management	300	300	600	1,000	1,500	2,500	2,500	3,500	3,500	3,500	**19,200**
HV vegetation management	4,000	4,200	5,500	6,500	8,500	8,500	9,500	9,500	9,500	9,500	**75,200**
Total	**4,300**	**4,500**	**6,100**	**7,500**	**10,000**	**11,000**	**12,000**	**13,000**	**13,000**	**13,000**	**94,400**

An additional benefit from introducing an electronic platform to manage data, reporting and service providers has been improved visibility and responsiveness to customers impacted by our maintenance programme. Greater visibility has made it easier for our customer support team and vegetation contract managers to access job information to provide a timely response to vegetation issues.



Our subtransmission underground cable network delivers electricity from Transpower's GXPs to substations across the region.

6.8 Underground cables – subtransmission

6.8.1 Summary

Our subtransmission underground cable network is a combination of 66kV and 33kV cables. Their main purpose is to deliver electricity from Transpower's GXPs to zone substations across the region. We have undertaken a risk assessment of our 66kV oil filled cables and 33kV XLPE cable joints. Our conclusion was that we should continue with our plans to replace our 66kV oil filled cables due to the Alpine Fault risk. For our 33kV cables our risk assessment recommended replacement of the joints which is largely complete.

6.8.2 Asset description

Table 6.8.1 shows that 66kV underground cable consists of older oil-filled cables and more recent XLPE cables. 40km of three core oil filled cables were installed between 1967 and 1981. XLPE cable has been installed since 2001 and it is still our current 66kV cable standard.

We have 37km of 33kV underground cable. It is mostly situated in the western part of Christchurch city, with sections of cable in Rolleston, Lincoln, Prebbleton and Springston. In recent years we have replaced an increasing amount of 33kV overhead line with underground cables as land has been developed and road controlling authorities have requested removal for road upgrades.

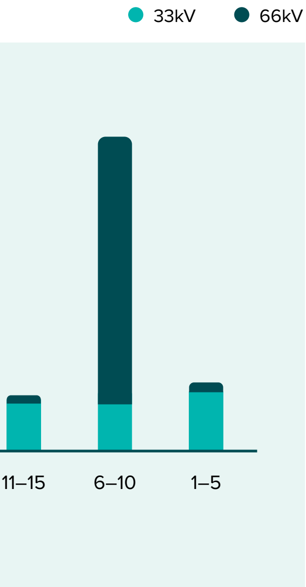
Cables are laid in the city to conform to the requirements of the Christchurch city plan. Cables are also installed as a result of customer driven work from developers requiring the undergrounding of our overhead subtransmission lines. Table 6.8.1 shows the age cable type quantities for our 33kV and 66kV network.

Table 6.8.1 Subtransmission cable length by type

Cable type	Length (km)		
	33kV	66kV	**Total**
PILCA	2	–	**2**
XLPE	39	50	**89**
3 core oil	1	40	**41**
Sub-total	42	90	
Total			**132**

Figure 6.8.1 shows the age profile for our 33kV and 66kV network. It can be seen that the majority of our assets are relatively new. The older 66kV cables are 3-core oil filled cables. Our newest 66kV XLPE cable was installed as part of our post-earthquake resiliency work.

Figure 6.8.1 Subtransmission cable network age profile



6.8.3 Asset health

6.8.3.1 Condition

We operate our 66kV cables conservatively which means they have not been subject to electrical aging mechanisms. We monitor the cables to ensure the integrity of their mechanical protection is maintained. We have replaced all the joints that indicated excessive movement of conductors. Some of our oil filled cables have returned poor sheath test results indicating some outer sheath damage. Our 66kV oil filled cable replacement programme will take this into consideration. We continue to inspect the joints as part of an ongoing maintenance plan.

Our 33kV cables are in relatively new condition. During the previous AMP period we identified some poor workpersonship on 33kV joints deemed as high risk, and as a result we undertook a joint replacement programme.

6.8.3.2 Reliability

Our 66kV cables were reliable prior to the earthquakes and in recent years. The performance of the cables is based on benchmarks such as SAIDI, SAIFI and defect incident records. An example of a minor defect would be termination issues such as oil leaks which are repaired under emergency maintenance.

Between FY15-FY18 we experience eight 33kV joint failures. Most of these failures were attributed to poor jointing technique or methods. Over the last two years we have had no 33kV joint failures. This is because the risks that were identified with the vulnerable 33kV joints have been repaired.

Figure 6.8.2 Subtransmission underground cable faults per 100km

* Source: PwC Electricity Line Business Information Disclosure Compendium 2016-2022

6.8.3.3 Issues and controls

Subtransmission cable failures are rare, but when they do occur, they can significantly impact our customers through loss of supply. Table 6.8.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 6.8.2 Subtransmission cable failure controls

Common failure cause	Known issues	Control measures
Material degradation	Partial discharge degrades the cable insulation which can result in complete failure leading to an outage	Ultrasonic and partial discharge monitoring of terminations in zone substations
Quality of installation	Poor quality of work while installing cable joints can lead to premature failure impacting reliability further down the track Poorly compacted fill material or naturally soft ground – for example organic clays and peat	Cable jointers are qualified, competent and trained to install specific products. We require them to be certified by the supplier Replacement programme for affected 33kV joints. Minimise high current loads to prevent thermal runaway of suspect joints Inspection of service providers during the laying of cables
Third party interference	Third parties dig up and damage our cables during road reconstruction	33kV and 66kV cables require standover process and consent application for any work Extensive safety advertising in the media. Free training on working safely around cables, including map reading and a DVD Orange coloured sheath 33kV cable is installed to allow easier identification Proactive promotion to service providers of cable maps and locating services

6.8.4 Maintenance plan

Our scheduled maintenance plan for subtransmission cables is summarised in Table 6.8.3 and the operational expenditure in the Commerce Commission categories is shown in Table 6.8.4. This includes a one year project to replace cable terminations at Middleton in line with the manufacturers recommendations.

Table 6.8.3 Subtransmission cable maintenance plan

Maintenance activity	Strategy	Frequency
Cable inspection	Oil filled cable oil level checks	2 monthly
	Cable sheath tests and repairs	From annually to at least 4 yearly
	Partial discharge testing	As required
	New or repaired cable benchmark testing	As required

Table 6.8.4 Subtransmission underground operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	50	50	50	50	50	50	50	50	50	50	**500**
Routine and corrective maintenance and inspections	115	105	45	55	65	55	45	55	65	55	**660**
Asset replacement and renewal	250	-	-	-	-	-	-	-	-	-	**250**
Total	**415**	**155**	**95**	**105**	**115**	**105**	**95**	**105**	**115**	**105**	**1,410**

6.8.5 Replacement plan

Our 66kV oil filled cables and joints have a medium to high risk of multiple faults occurring should the Alpine Fault rupture. Recent research from Te Herenga Waka–Victoria University of Wellington estimates that there is a 75% chance of a major Alpine Fault earthquake in the next 50 years.

To minimise the risk of failure and to provide security and resilience for our community, the replacement of our 40km of oil filled 66kV cables will be integrated into a wider 66kV architecture project, see Section 7.4. The good condition and performance for our remaining XLPE subtransmission cables means there are no further replacement programs in the AMP forecast.

6.8.5.1 Disposal

Our asset design standards for underground cable contain information on how to risk assess works in and around potentially contaminated land, and mandates the use of suitably qualified and experienced personnel to advise on appropriate disposal options where required. We have a network specification that details disposal requirements and options for all work relating to excavations, backfilling, restoration and reinstatement of surfaces.

90% of our network of 11kV underground cables are in the urban area of Christchurch also known as Region A.

6.9 Underground cables – distribution 11kV

6.9.1 Summary

90% of our network of 11kV underground cables are in the urban area of Christchurch also known as Region A. We proactively monitor, test and maintain our 11kV cables. While our cable failure rate remains steady, we have budgeted expenditure to investigate methodologies to monitor our 11kV cable condition to inform better investment decisions and timing for replacement.

6.9.2 Asset description

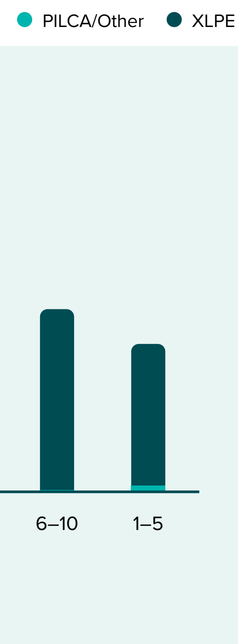
There are two main types of 11kV underground cable in our network:

- **PILCA** – paper insulated lead armour cables
- **XLPE** – cross linked polyethylene insulated power cables

Table 6.9.1 11kV cable length by type

Cable type	Length (km)
PILCA	1,532
XLPE	1,280
Others	0
Total	**2,812**

Figure 6.9.1 11kV cable age profile



6.9.3 Asset health

6.9.3.1 Condition

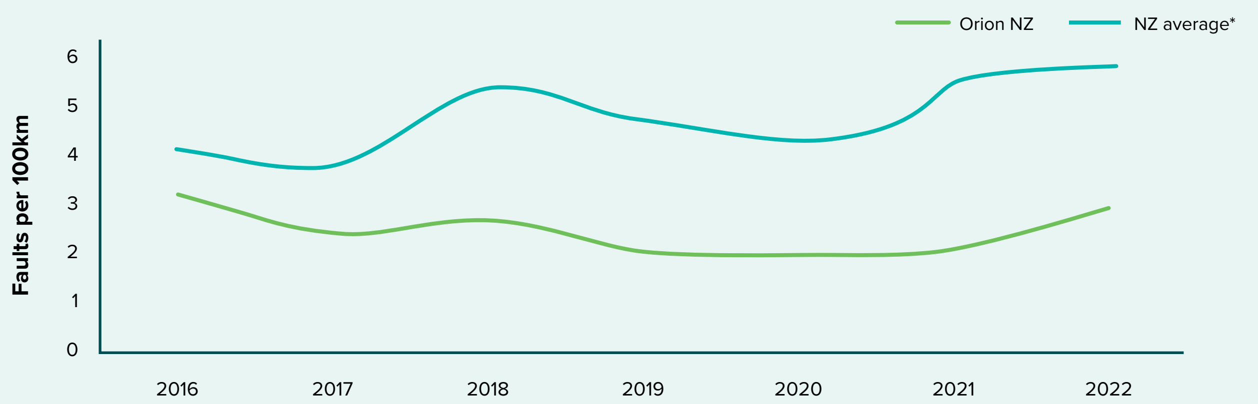
The condition of these cables are largely assessed by monitoring any failures. Condition testing of a sample of varying cable types and ages has been undertaken using the partial discharge mapping technique. A limited amount of partial discharge was noticeable in a few joints. However, there were no major areas of concern.

6.9.3.2 Reliability

In FY21, 11kV cable faults contributed to 16% of the total SAIDI and 25% of the total SAIFI. In recent years, the majority of failures have occurred in a joint section of the cable and half of these are located in or near Christchurch's Residential Red Zone. Options for the future of Residential Red Zone land are being explored with the community, led by Christchurch City Council. In the meantime, we are maintaining this network until its future is decided.

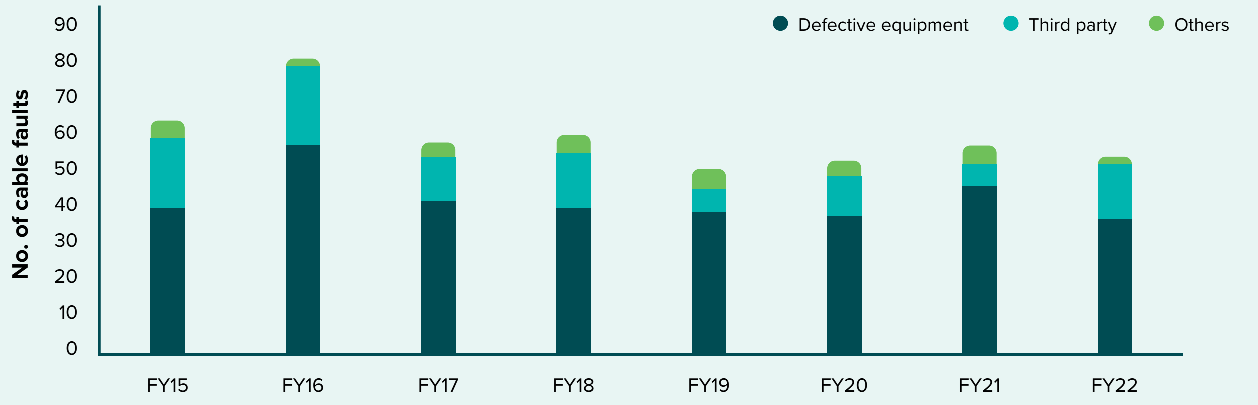
Our termination maintenance programmes have been effective in keeping the failure numbers low. The number of cable, joint and termination failures, excluding earthquakes, is shown in Figure 6.9.3. 'Others' refers to vehicle collision and weather related events where it caused a failure on the underground to overhead termination located on a pole. It also includes underground faults where the cause is unknown.

Figure 6.9.2 Number of 11kV underground cable failures and the corresponding SAIDI and SAIFI



* Source: PwC Electricity Line Business Information Disclosure Compendium 2015-2022

Figure 6.9.3 Cause of 11kV cable faults



6.9 Underground cables – distribution 11kV continued

We have seen a downward trend in third party cable strikes and other failure modes since 2014. This is due to a combination of improved excavation compliance from third party service providers, repair of earthquake damage being completed and the proactive maintenance of susceptible cable terminations. We believe the current number of failures and performance is satisfactory. The majority of 11kV cable plant failure is broken down to approximately 50% joint, 40% run of the cable and 10% termination. It appears that the underlying cause of failure could be due to joints reaching end of life. 'Run of the cable' failure is due to harsh environment, damaged from latent third party activity or poor insulation quality.

6.9.3.3 Issues and controls

Table 6.9.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 6.9.2 11kV cable failure control

Common failure cause	Known issues	Control measures
Workpersonship	Termination and joint failures can occur due to poor quality of work. It can lead to partial discharge which if not detected can cause explosive failure resulting in an outage and possible safety and environmental consequences	Cable jointers are qualified, competent and trained to install specific products. Ultrasonic and partial discharge monitoring of terminations in zone substations Routine substation inspections identify failing 11kV terminations
Third party activities	Third parties can damage our cables while undertaking civil works through either direct contact damage or by causing improper ground settlement through incorrect fill material and compacting	We run a cable awareness programme targeted at external service providers to minimise the risk of cable disturbance while digging in close proximity to network cables Orange coloured sheath cables are installed to allow easier identification We undertake inspections during the laying of cables Proactive promotion to service providers of cable maps and locating services No joints are allowed within road intersections

6.9.4 Maintenance plan

We have cable terminations to MSUS. Although failure rates are beginning to decrease, increased service provider costs mean our expenditure on this emergency work is not reducing.

The maintenance plan is shown in Table 6.9.3.

There is also expenditure allocated in FY26 and FY27 to investigate an effective methodology to monitor 11kV cable condition. This will inform targeted replacement decisions as the fleet continues to age.

Table 6.9.3 11kV cable maintenance plan

Maintenance activity	Strategy	Frequency
MSU terminations	Inspections of MSU terminations, reporting grease terms and corona discharge	6 months
Diagnostic cable testing	Partial discharge and Tan Delta testing	Targeted ongoing

An annual forecast of operational expenditure in the Commerce Commission categories is shown in Table 6.9.4.

Table 6.9.4 11kV underground operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	**14,000**
Routine and corrective maintenance and inspections	400	400	1,010	1,010	510	510	510	510	510	510	**5,880**
Total	**1,800**	**1,800**	**2,410**	**2,410**	**1,910**	**1,910**	**1,910**	**1,910**	**1,910**	**1,910**	**19,880**

6.9.5 Replacement plan

Significant levels of age-related replacement are not expected for at least another decade. Any cable replacements will be undertaken as part of other works such as a reinforcement/switchgear replacement project or a local authority driven underground conversion project.

Some expenditure is forecast annually to allow for the replacement of short sections (<100m) of 11kV underground cable identified as being unreliable. These sections are predominantly in earthquake damaged areas.

Additional 11kV cables are installed as a result of the following:

- reinforcement plans – refer to Section 7 – Network development proposals
- conversion from overhead to underground as directed by Christchurch City and Selwyn District Councils
- developments as a result of new connections and subdivisions

An annual forecast of cable replacement capital expenditure in the Commerce Commission categories is shown in Table 6.9.5.

Table 6.9.5 11kV underground replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Distribution & LV cables	200	200	800	800	800	800	800	800	800	800	**6,800**
Total	**200**	**200**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**6,800**

6.9.5.1 Disposal

Our asset design standards for underground cable contain information on how to risk assess works in and around potentially contaminated land, and mandates the use of suitably qualified and experienced personnel to advise on appropriate disposal options where required. Our network specification details disposal requirements and options for all work relating to excavations, backfilling, restoration and reinstatement of surfaces.

Our 400V cable network is 3,300km and delivers electricity to street lights and customer's premises largely in Region A.

6.10 Underground cables – distribution 400V

6.10.1 Summary

Our 400V cable network delivers electricity to street lights and customer's premises largely in Region A. We also have around 60,000 distribution cabinets and distribution boxes installed on our 400V cable network. Generally, this cable network, cabinets and boxes are reliable and resilient. We are currently in the process of carrying out a supply fuse relocation programme to increase safety for our customers and the public. There is also placeholder allowance from FY28 onwards to replace end of life cable.

6.10.2 Asset description

The 400V underground asset class comprises two distinct subsets: LV cables and LV enclosures.

LV cables

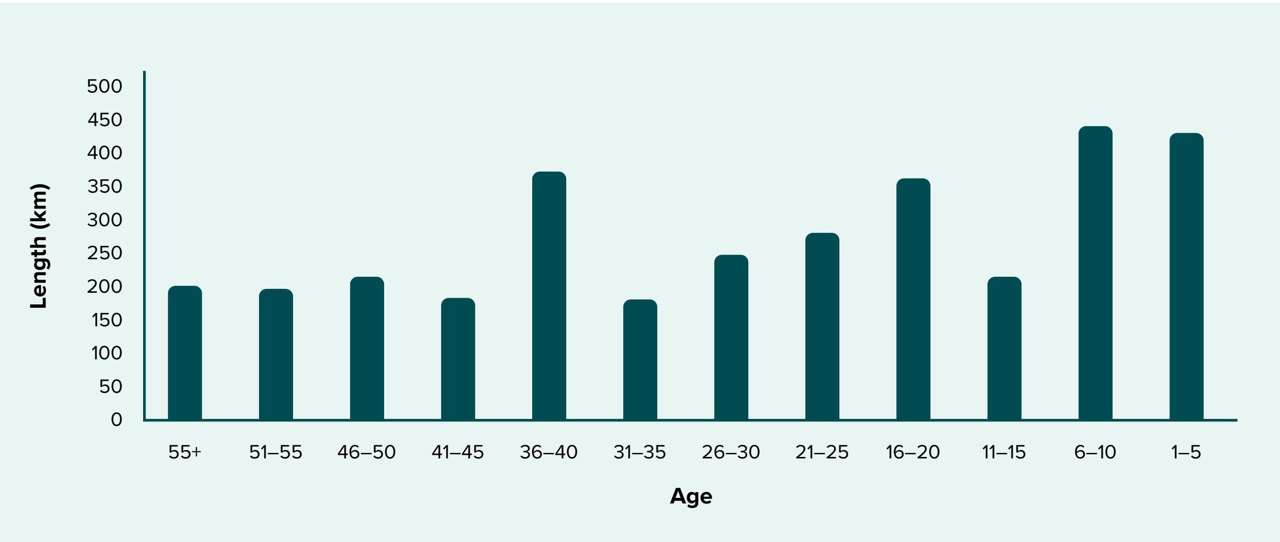
We have two groups of cables: distribution cables and street-lighting cables as shown in Table 6.9.1. They are:

- **Distribution cables –** the earlier cables are of paper/lead construction. PVC insulation was introduced in 1966 to replace some PILCA cables. XLPE insulation was introduced in 1974, mainly because it has better thermal properties than PVC
- **Street-lighting cables –** approximately 60% of this cable is included as a fifth core within 400V distribution cables

Table 6.10.1 400V cable and street-lighting networks cable type

Cable type	Length (km)
PVC	601
PILCA	599
XLPE	2,148
Total	**3,348**
Street-lighting cable	2,804

Figure 6.10.1 LV cable age profile



LV enclosures

We have two groups of enclosures, see Table 6.10.2. They are:

- **Distribution cabinets –** these cabinets allow the system to be reconfigured if each radial feeder is capable of supplying or being supplied from the feeder adjacent to it. There are two types: steel and PVC cover on a steel frame
- **Distribution boxes –** generally installed on alternate boundaries on both sides of the street. Several types of distribution box are in service and all are above ground. The majority are a PVC cover on a steel base frame, although some older types are concrete or steel

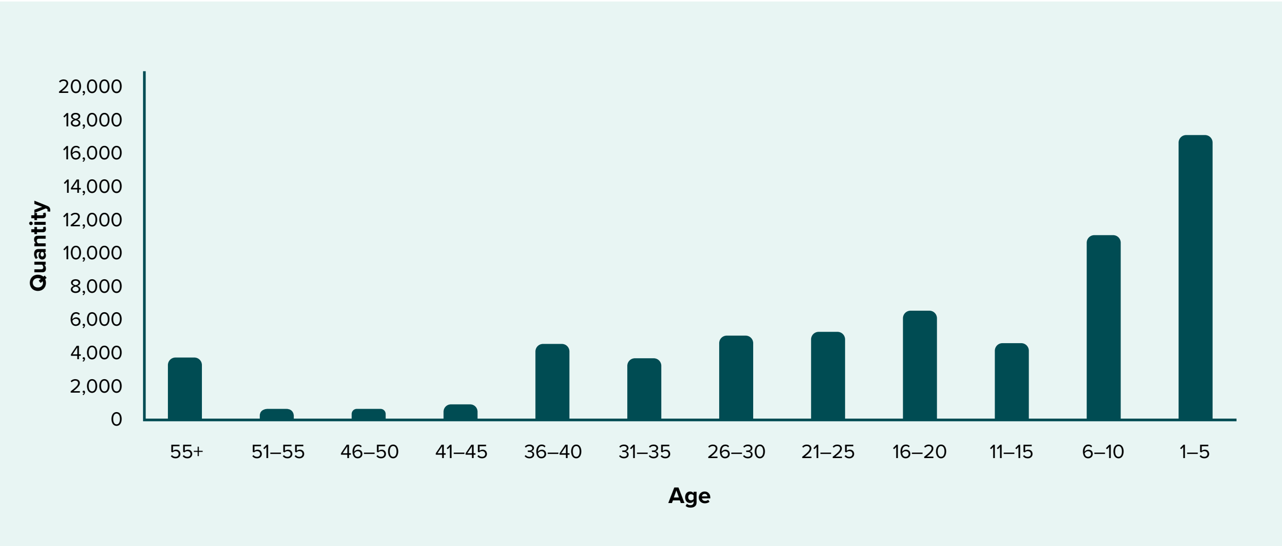
The age profile is shown in Figure 6.10.2.

We inspect our distribution cabinets and boxes every five years, with any defects remedied in a subsequent contract.

Table 6.10.2 Distribution enclosure type

Distribution enclosure type	Quantity
Distribution cabinet	6,775
Distribution box	57,240
Total	**64,015**

Figure 6.10.2 LV enclosures age profile



6.10.3 Asset health

6.10.3.1 Condition

We inspect our distribution cabinets and boxes every five years, with any defects remedied in a subsequent contract. We cannot readily inspect the condition of the LV underground cables. The average age of the cables is 32 years old and the failure rates do not indicate the need for a conditions-driven replacement program over the next AMP period.

However, recent modelling of our LV networks has indicated that some cables are operating above rated capacity which can reduce asset lifespan. We have allocated additional budget to upgrade our LV network cables in the areas identified to relieve constraints.

6.10 Underground cables – distribution 400V continued

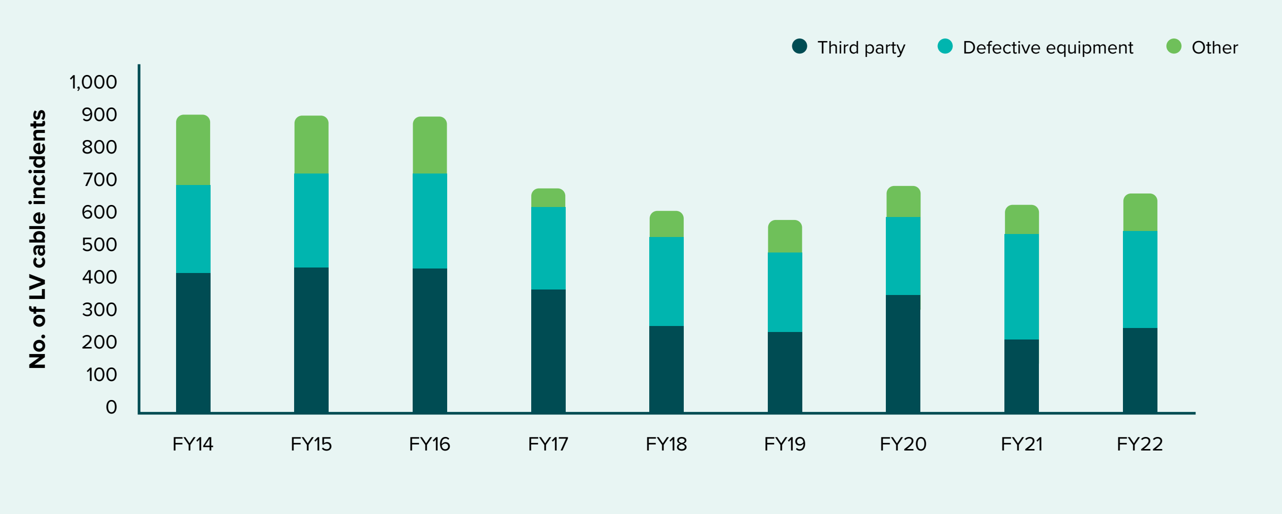
6.10.3.2 Reliability

We are not required to record SAIDI/SAIFI for our LV networks. However, for prudent asset management and to ensure we maintain an acceptable service to our customers we collect performance data on our LV system. The number of LV underground call-outs our service providers address under emergency maintenance is shown below.

The majority of call-outs relate to third party damage and service or network cable failures. Vegetation, vermin and weather prompt a small number of call-outs.

Overall, our LV cable network performs well and we are seeing a downward trend in incidents on our LV underground cable. The other faults captured are mostly faults with street lighting which is owned by the Christchurch City Council. An Orion operator is normally called to attend the site for faults with street lighting.

Figure 6.10.3 Cause of LV cable incidents



6.10.3.3 Issues and controls

Table 6.10.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 6.10.3 LV cable network failure controls

Common failure cause	Known issues	Control measures
Material degradation	Quality of work installing cable joints and terminations	Regular inspections. Cable jointers are qualified, competent and trained to install specific products
	Historically many customer service cables were connected directly to the underground network cables by way of a tee joint with the customer protection fuses in their meterbox	For increased safety we have introduced a supply fuse relocation programme where these fuses are moved to newly installed distribution boxes on the property boundary
Third party activities	Third parties dig up and damage our cables and road reconstruction	Identified shallow conductors are addressed Cable Digging Awareness Programme – A cable awareness programme running in association with external service providers to minimise the risk of cable interruption for any digging in close proximity to the network cable New cable is now required to be installed with an orange coloured sheath to allow easier identification Extensive public safety advertising campaigns

6.10 Underground cables – distribution 400V continued

6.10.4 Maintenance plan

Our scheduled maintenance plan is summarised in Table 6.10.4.

Table 6.10.4 400V underground maintenance plan

Asset	Maintenance Description	Frequency
Distribution cables	Visual inspection of insulation on cable to overhead terminations. Where insulation is degraded due to the effects of UV light it is scheduled for rectification. The inspection process is under review to provide better condition data	5 years
Distribution enclosures	Visual inspection programme of the above-ground equipment and terminations. Major defects identified and scheduled for rectification. The inspection process is under review to provide better condition data	5 years

Table 6.10.5 400V underground operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	**16,000**
Routine and corrective maintenance and inspections	1,065	1,065	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	**12,930**
Total	**2,665**	**2,665**	**2,950**	**2,950**	**2,950**	**2,950**	**2,950**	**2,950**	**2,950**	**2,950**	**28,930**

6.10.5 Replacement plan

We are continuing with the supply fuse relocation programme to reduce risks associated with a historical practice where some LV supply fuses were installed in the customer's meter box. This programme, which relocates the fuse to a distribution box on the property boundary, is scheduled for completion in FY29. We are also upgrading our existing distribution cabinets to a more secure design.

Placeholders have been put in for end of life cable replacement from FY28 and beyond. It is expected that due to EV take-up and ageing cables, proactive replacement will be needed to provide satisfactory service to our customers.

Table 6.10.6 400V underground replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Distribution and LV cables	558	658	1,195	1,195	3,195	4,195	5,195	5,195	5,195	5,195	**31,776**
Other reliability, safety and environment	7,440	7,440	4,650	5,290	6,190	2,440	-	-	-	-	**33,450**
Total	**7,998**	**8,098**	**5,845**	**6,485**	**9,385**	**6,635**	**5,195**	**5,195**	**5,195**	**5,195**	**65,226**

6.10.5.1 Disposal plan

Our asset design standards for underground cable contain information on how to risk assess works in and around potentially contaminated land, and mandates the use of suitably qualified and experienced personnel to advise on appropriate disposal options where required. Our network specification details disposal requirements and options for all work relating to excavations, backfilling, restoration and reinstatement of surfaces.

Switchgear contributes to our asset management objectives by providing capability to control, protect and configure the electricity network.

6.11 Switchgear

6.11.1 Summary

Switchgear contributes to our asset management objectives by providing capability to control, protect and configure the electricity network. Our switchgear is in well maintained condition to meet our service level targets. We manage the performance of the fleet through routine maintenance and inspections. Our replacement programmes manage an aging population of oil filled circuit breakers and other switchgear nearing end of life. Our MSU replacement programme continues to grow to manage the aging population.

6.11.2 Asset description

In this section we discuss the types of circuit breaker and switchgear we install on Orion's network.

Circuit breakers

Circuit breakers are installed to provide safe interruption of both fault and load currents, for example, during power system abnormalities. They are strategically placed in the network for line/cable, transformer and ripple plant protection.

Table 6.11.1 Circuit breaker description by type

Voltage	Type	Description
66kV	Circuit breaker (zone substation)	These are installed at zone substations predominately in outdoor switchyards. The exceptions being Armagh, Dallington, Marshland, McFaddens, Lancaster, Belfast and Waimakariri zone substations where the 'outdoor design' circuit breakers have been installed indoors in specially designed buildings. The majority of our 66kV circuit breakers use SF_6 gas as the interruption medium
33kV	Circuit breaker (zone substation)	A mix of outdoor and indoor. Those installed pre-circa 2001 are mainly outdoor minimum oil interruption type. We are now moving from outdoor to indoor switchgear. Where suitable we now install indoor metal clad circuit breaker switchboards. These circuit breakers have the advantage of improved security and public safety. Since 2018, installed indoor circuit breakers have been rated for full arc containment, providing an increased level of safety
11kV	Circuit breaker	Substation circuit breakers are installed indoors and used for the protection of primary equipment and the distribution network. The older units use oil or SF_6 gas as an interruption medium, while those installed since 1992 are a vacuum interruption type. Circuit breakers installed since 2019 are rated for full arc containment, providing an increased level of safety
11kV	Line circuit breaker (pole mounted)	These have reclose capability. They are installed in selected locations to improve feeder reliability by isolating a portion of the overall substation feeder

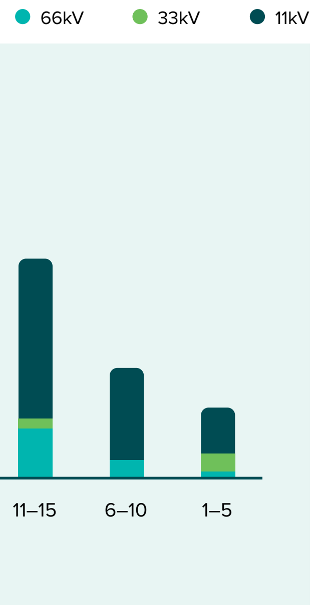
Table 6.11.2 Circuit breaker quantities by type

Voltage	Asset Type	Quantity
66kV	Oil	7
	SF_6	107
33kV	Oil	24
	SF_6	6
	Vacuum	47
11kV	Oil	630
	SF_6	34
	Vacuum	830
	Total	**1,685**

Our switchgear is in well maintained condition to meet our service level targets.

Figure 6.11.1 shows the age profile for our circuit breakers. There is a large portion of aged 11kV circuit breakers and a number of aging 33kV and 66kV circuit breakers.

Figure 6.11.1 Circuit breakers age profile



Switches

Switches are used to de-energise equipment and provide isolation points so our service providers can access equipment to carry out maintenance or emergency repairs. The type of switches are described in Table 6.11.3.

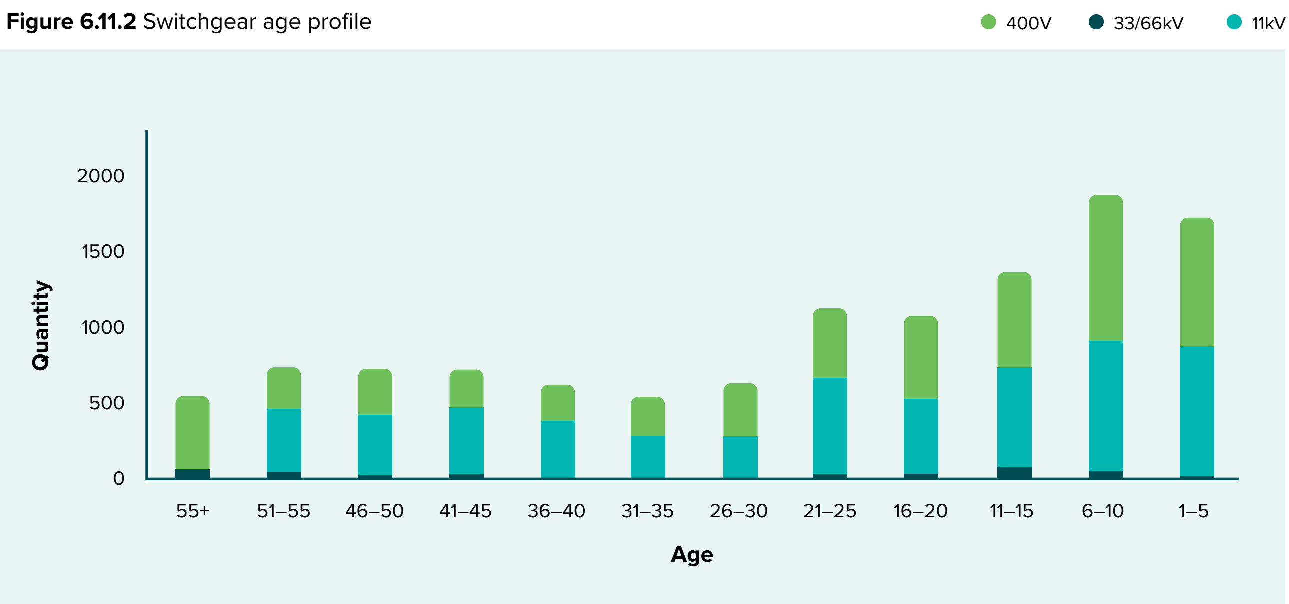
Table 6.11.3 Switchgear description by type

Voltage	Type	Description
66kV & 33kV	Substation Disconnector (DIS)	Disconnectors are used as isolation points in the zone substation switchyard to reconfigure the substation bus for fault restoration, or for isolating plant for maintenance. They are typically mounted on support posts or hang from an overhead gantry. Most are simple hand operated devices. Since 2016, we have added motor operated disconnectors to some sites, which are safer, as the operator can maintain a safe distance during switching
33kV & 11kV	Line Air Break Isolator (ABI) (pole mounted)	These are installed on our rural overhead network and some have load break capability. We no longer install new ABIs and have been replacing old ABIs with line switches
	Line switch (pole mounted)	These units are rated at 630A with a vacuum load breaking switch. They are installed to be operated on-site by hot-stick or remote operation. These switches are installed when older ABIs are due for replacement
11kV	Magnefix Ring Main Switching Unit (MSU)	MSU are independent manually operated, quick-make, quick-break design with all live parts fully enclosed in cast resin. Normally all three phases are operated simultaneously with a three phase bridge, but can be switched individually if necessary. These switches are the predominant type installed in our 11kV cable distribution network
	Ring-main unit (RMU)	These units are fully enclosed metal-clad 11kV switchgear. They typically have load-break switches and or vacuum circuit breakers. With motorisation and the addition of electronic protection relays they can be fully automated. They may be installed in a substation or outdoors. They are designed for arc fault containment, which ensures a high level of safety in the rare event of asset failure
400V	Low voltage switch	Installed generally in distribution substations, these switches form the primary connection between 11kV/400V transformers and the 400V distribution network, giving isolation points and fusing capability using high rupturing current (HRC) links. All new installations are of the DIN type instead of the exposed-bus (skeleton) and V-type fuse design

Table 6.11.4 Switch quantities by type

Voltage	Asset Type	Quantity
66kV / 33kV	Substation disconnector	314
33kV	Line ABI	6
11kV	Line switch	272
	Line ABI	525
	MSU	4,723
	RMU	163
400V	Low voltage switches	5,615
	Total	**11,618**

Figure 6.11.2 Switchgear age profile



6.11.3 Asset health

6.11.3.1 Condition

Overall our circuit breaker fleet is in good serviceable condition. Methods of condition monitoring, such as partial discharge measurement, have enabled us to detect defects at an early stage. The majority of ring-main units are in reliable condition, however there is a known type issue for a small amount of the fleet, see table 6.11.5. The line switches are a relatively new asset to the network which exhibit no significant degradation or defects. The majority of our line ABIs are in serviceable condition however, there are some known type issues and some older types are approaching the end of life. A technical investigation on a sample of our MSU switchgear in 2020 helped us better establish their end of life criteria and expected life. The MSU fleet was shown to be in suitable condition and still fit for purpose with maintenance. Our low voltage switches exhibit no significant degradation or defects.

A technical investigation on a sample of our MSU switchgear in 2020 helped us better establish their end of life criteria and expected life.

Figure 6.11.3 33kV / 66kV circuit breaker condition profile

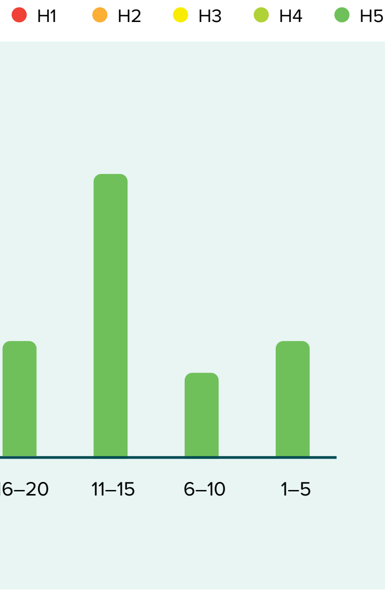
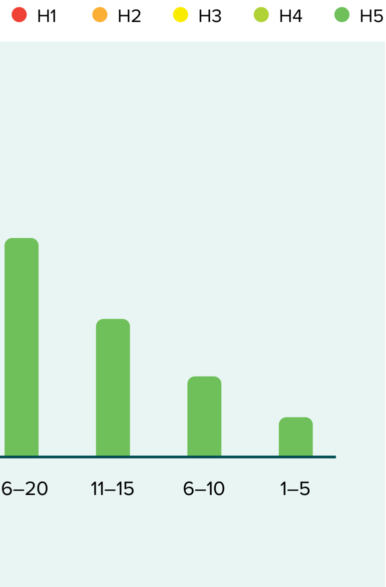


Figure 6.11.4 11kV circuit breaker condition profile



6.11.3.2 Reliability

Switchgear contributes to our asset management objectives by providing capability to control, protect and configure the electricity network. Therefore, we strive for a good performance due to the potentially serious consequences of asset failure.

Our approach for this asset class is to achieve a high level of reliability, mitigate safety and environmental hazards, and to avoid major failures. A summary of switchgear performance by type is shown in Table 6.11.5.

Table 6.11.5 Performance of switchgear

Voltage	Asset Type	Performance
66kV / 33kV	Substation disconnectors	Overall the performance level has been satisfactory. Some older disconnectors are experiencing performance issues and have required servicing or repairs under emergency maintenance. We will replace problematic units in this AMP period through our replacement programme
66kV / 33kV / 11kV	Circuit breakers	The overall performance of our 33kV and 66kV circuit breakers is good. Our SF_6 circuit breakers are aging and part of the aging process is weathering of the gaskets. This causes the gaskets to harden which weakens their ability to maintain a seal. We have initiated a maintenance programme to replace gaskets and o-rings for our SF_6 circuit breakers Overall, our 11kV circuit breaker fleet is providing satisfactory performance. Our aging oil filled 11kV circuit breakers continue to provide reliable service, however a failure of these assets could be catastrophic, with the potential to cause burns and harm to the environment. We are phasing out all oil filled circuit breakers as they reach their end of life. We replace oil filled 11kV circuit breakers with arc contained vacuum circuit breakers. These require minimal maintenance and meet modern performance, environment and safety standards
33kV	Line ABI	Our remaining units are routinely maintained and are most often performing reliably. These are progressively being replaced by line switches to allow remote control capability in preparation for a potential automatic power restoration system
11kV	Line switch	These are relatively new to our network, performing well and no defects or failures to date
	Line ABI	One model of ABI is reporting a high failure rate due to faulty insulators. Refer to Section 6.10.5.5 for the replacement programme. We are phasing out ABIs and prefer to install line switches due to the remote operation capability and lower maintenance requirements
	MSU	These units are ageing but have performed reliably. Any failure is usually due to secondary factors such as a cable termination failure. On average there has been two failures per year. The failure rate has decreased slightly in recent years. Reasons for failure are due to corrosion and faulty contacts Defects are identified by routine inspection and testing and rectified by either our scheduled or reactive maintenance programme We have identified a safety risk where unfused MSUs may contribute to prolonged clearance times for transformer and LV panel faults. We are addressing this issue through our replacement programme
	RMU	Apart from a small number of units that have experienced internal phase to earth faults, the majority of our RMUs are performing well and are reliable. Most failures in these units are usually due to secondary factors such as cable terminations and are dealt with in our regular inspections and maintenance programmes
400V	Low voltage switches	The older ‘skeleton’ type panels and switches have good electrical performance, however, the exposed busbars create safety risks. We install additional barriers to reduce the likelihood of inadvertent contact Some issues have become apparent with DIN type switches. These have generally been related to overheating created by the quality of connection and installation. We are addressing these in our maintenance programme and also targeted replacement of our older exposed bus type where the opportunity arises

6.11.3.3 Issues and controls

Switchgear failures are rare, but if they fail they have a high potential to pose a safety risk to our staff and service providers. Table 6.11.6 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures. These controls enable us to maintain a safe, reliable, resilient system and protect the environment as set out in our asset management investment drivers in Section 2.5.1.

Table 6.11.6 Switchgear failure controls

Common failure cause	Known issues	Control measures
Insulation deterioration	Aging insulation medium (e.g. oil), insulation medium leakage (both oil and SF_6) and moisture in insulation medium	Partial discharge testing and monitoring programme Targeted reliability-based maintenance programme Repair and refurbishment if possible Replacement if ongoing maintenance and refurbishment is not economical or not possible
	Internal flashover has occured on a small number of RMUs manufactured between 2014 and 2017	The RMUs do not present a significant safety risk to our people or public. We no longer install this model RMU and changed our operating procedures to minimse the risk of further failures
Breaker contact surface degradation	MSU contacts in coastal areas are particularly susceptible to corrosion	Heaters are installed to prevent condensation. Targeted maintenance programme for coastal sites. Parts replacement/refurbishment if possible or economical
Cable termination degradation	Aging and partial discharge from inadequate clearance, condensation and contamination and poor-quality terminations	Partial discharge testing and monitoring programme Routine maintenance programme of cleaning, repair and/or re-termination
Mechanical failure	Stiction of mechanism from prolonged inactivity. Aging, wear and fatigue	Routine maintenance to prevent failure. Repair if economical and spares available. If not, then replacement is the only option
Pests and vermin	Bird strikes on outdoor circuit breaker due to insufficient clearances	Planned replacement and design for sufficient clearances

6.11.4 Maintenance plan

We use both routine and reliability based inspection and maintenance for our circuit breakers and switchgear. The routine maintenance programme applies to all the assets in this category. Reliability based programme is additional inspection, testing and maintenance work targeted at assets with poorer condition or reliability to maintain their performance and mitigate against failure. Inspections, testing and major maintenance are carried out at regular intervals as shown in Table 6.11.7.

Table 6.11.7 Switchgear maintenance plan

Asset type	Description	Inspection frequency	Maintenance interval
MSU	Scheduled inspection – check heater operation, signs of PD, dust covers fitted. Report defects or contamination found.	6 months	As required
	Scheduled maintenance – MSUs near the coast are routinely maintained	6 months	4 years
RMU	Inspect and report defects	2 months (Zone) 6 months (Distribution)	As required
ABI	Scheduled maintenance – clean, inspect and lubricate moving parts and contacts. Clean insulators, inspect terminations	–	5 years
Disconnectors	Scheduled maintenance – clean, inspect and lubricate moving parts and contacts. Clean insulators, inspect terminations	–	4 or 8 years
400V LV switches	Scheduled inspection – visual inspection, and defect rectification	Substations - no more than 6 months All other LV - no more than 5 years	As required
	Scheduled inspection – inspect & report defects	2 months (Zone) 6 months (Distribution)	–
Circuit breakers	Non-intrusive survey of equipment using online partial discharge detection methods to identify insulation defects	Variable based on age, criticality & defect history of the asset	–
	Scheduled maintenance – clean and lubricate moving parts, repair or replace contacts, tripping tests, electrical diagnostic tests, service or replace oil	–	4 or 8 years
Line switches and reclosers	Scheduled maintenance – exterior and control relay are inspected annually. Our SCADA provides initial indication of problems	12 months	8 years

An annual forecast of operational expenditure in the Commerce Commission categories is shown in Table 6.11.8. The forecast is based on historical costs of maintenance and repair. The assumptions for our forecast are:

- The volume of assets will remain approximately constant over the forecast period, which already accounts for any additional inspection and surveillance of our older circuit breakers and switchgear
- The failure rate will remain constant

Table 6.11.8 Switchgear operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	325	325	325	325	325	325	325	325	325	325	**3,250**
Routine and corrective maintenance and inspections	1,125	1,180	1,430	1,460	1,585	1,565	1,640	1,650	1,535	1,485	**14,655**
Total	**1,450**	**1,505**	**1,755**	**1,785**	**1,910**	**1,890**	**1,965**	**1,975**	**1,860**	**1,810**	**17,905**

6.11.5 Replacement plan

We have a proactive replacement programme for our switchgear where higher risk assets are replaced first.

On average we expect our circuit breakers to last 50 to 55 years. We have an ageing asset fleet for certain types of switchgear and we balance replacing assets too soon with our resource availability.

We prioritise replacement using a risk-based approach.

All circuit breakers have been reviewed based on several factors such as safety, condition, performance, criticality and operation.

Safety issues are given a high weighting to ensure protection of the public, employees and service providers. Performance and asset condition are considered on an individual basis and are used to develop the replacement programme.

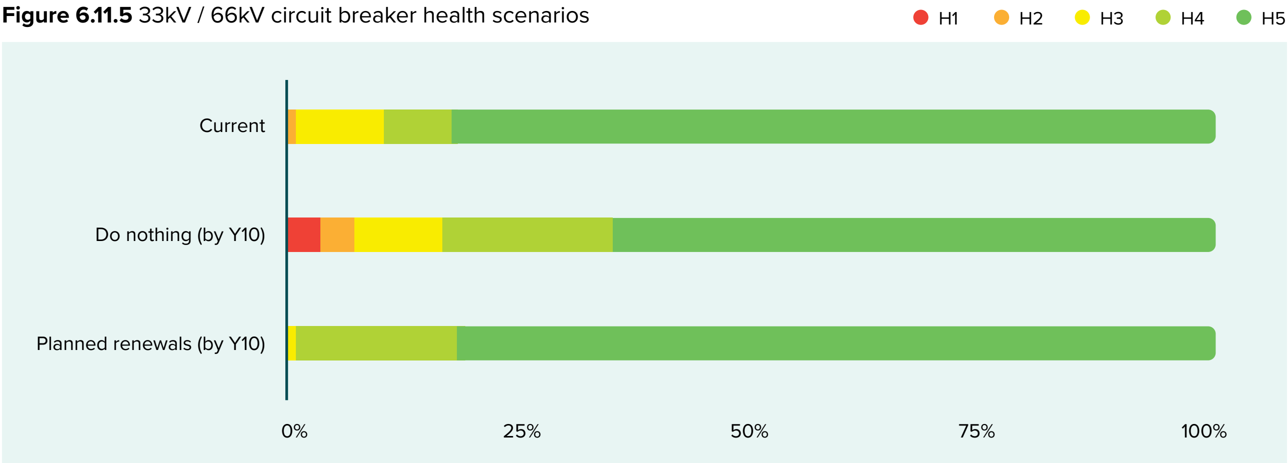
The criticality and location, i.e., zone substation, is also considered and factored into the programme.

Older circuit breakers are normally replaced with a modern equivalent, however in some cases they are replaced with a high voltage switch if it is deemed suitable. The replacement programme is regularly reviewed to consider the changing requirements of the network.

66kV / 33kV circuit breakers

We analyse different scenarios/options for the replacement programme to look at their impact on risk profiles. We compare the health index profiles of the 66kV and 33kV circuit breakers today with that expected upon completion of the 10-year replacement and the do nothing scenario (Figure 6.11.5).

Figure 6.11.5 33kV / 66kV circuit breaker health scenarios



- **Do nothing scenario –** as a means of comparison, we looked at a theoretical scenario without a replacement programme. This showed the risk of a major failure of circuit breakers would increase. This poses a risk on safety of personnel and environmental impacts, which is unacceptable as it would breach a number of our asset management objectives and service level targets.
- **Planned renewal scenario –** shows the circuit breaker health profile improves over the 10-year period as we continue to replace the assets as they approach the end of their reliable life. This health profile also includes asset replacement driven by network growth.

6.11 Switchgear continued

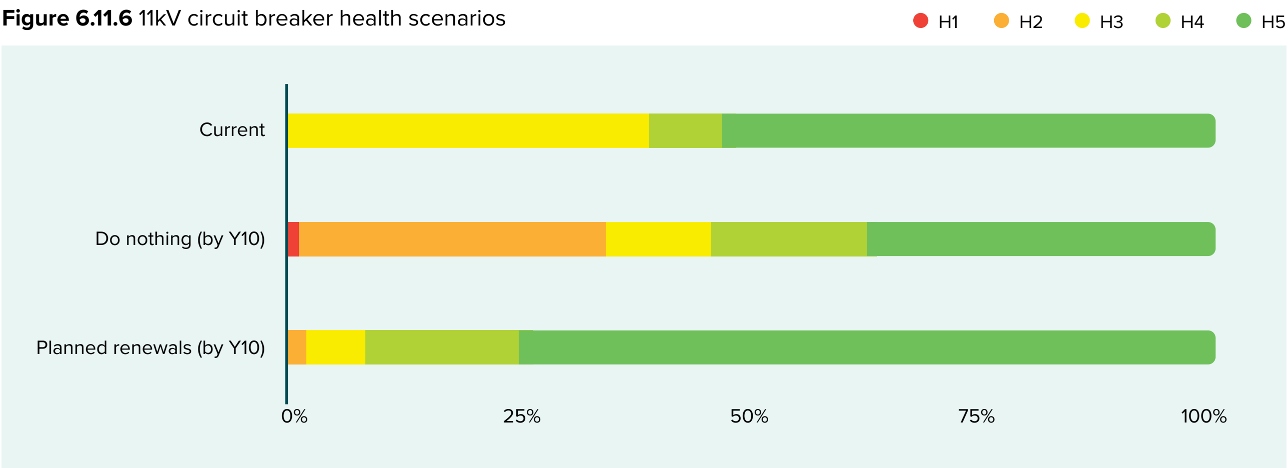
11kV circuit breakers

The scenario in Figure 6.11.6 represents the health comparison of our current versus future 11kV circuit breaker fleet. We have a large population of older oil filled circuit breakers due for renewal over the AMP period. These are split 35% in zone and 65% in distribution substations. Their replacement is an appropriate response to minimise the potential safety risks of ageing 11kV circuit breakers.

During the past 12 months we completed 11kV circuit breaker replacement at Oxford-Tuam zone substation.

Over the next 12 months we plan to complete 11kV circuit breaker replacement at our Heathcote zone substation and commence 11kV circuit breaker replacement at Hawthornden zone substation. We also have an ongoing circuit breaker replacement programme for our distribution circuit breakers. These are usually replaced with RMUs or MSUs. In the next 12 months we plan to carry out replacement at four distribution substation sites.

Figure 6.11.6 11kV circuit breaker health scenarios



66kV / 33kV substation disconnectors

For these assets, we observe condition and risk scenarios with CBRM modelling. Older wedge type disconnectors can have alignment issues, so we are prioritising replacement of these to lower maintenance requirements and improve operational performance.

33kV line ABI

Our small population of 33kV ABI are progressively being replaced by line switches. Replacement is based on their condition and criticality, but it is planned to be a steady number over the next four years.

11kV line ABI

As ABIs reach their end of life we are replacing these with vacuum line switches due to their superior reliability, lower maintenance requirements, safer operating capability and the ability for remote operation and fault detection which can improve restoration times.

11kV switches

MSU replacement is based on a combination of age and risk. The aged based replacement targets MSUs that are near end of life and, risk-based replacement targets unfused MSUs that won't provide adequate arch flash protection in the event of an LV flash over. We are planning to replace a third of unfused MSUs over the next ten years, targeting the oldest units first. The age-based replacement rate will need to increase over this AMP period as we see a significant number of MSUs reach end of life. Approximately 12% of our MSU fleet is going to reach end of life in the next 10 years.

Low voltage switch

Some of the older exposed bus type LV switches associated with unfused MSUs have been identified that the low voltage arc flash incident energy presents a serious hazard. We have a targeted programme to replace these units to mitigate the risk. Other LV switches that are end of life will be replaced as part of the switchgear renewal works. Most skeleton LV panels are at sites with aging or end of life MSUs, therefore we anticipate an increase in LV panel replacements as we replace more end of life MSUs.

An annual forecast for our replacement capital expenditure in the Commerce Commission categories is shown in Table 6.11.9.

For switchgear assets where CBRM models are used, we take a bottom-up approach to forecasting. While past costs can be helpful for predicting future costs for simple replacement programs, we find that a more thorough, site-by-site analysis is needed for more complex projects. This involves looking at different engineering options and developing business cases to arrive at a more accurate forecast of capital expenditure.

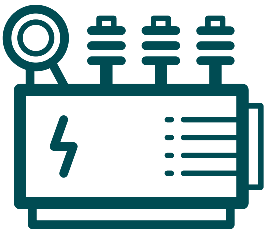
Table 6.11.9 Switchgear replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Subtrans-mission	30	30	-	-	-	-	-	-	-	-	**60**
Zone substation	2,645	2,240	6,688	9,774	8,096	3,530	4,625	3,621	1,275	1,150	**43,644**
Distribution switchgear	6,407	5,355	9,239	11,639	13,039	13,039	12,739	12,739	12,739	12,378	**109,313**
Total	**9,082**	**7,625**	**15,927**	**21,413**	**21,135**	**16,569**	**17,364**	**16,360**	**14,014**	**13,528**	**153,017**

6.11.5.1 Disposal

Our Hazardous Substances procedures detail the disposal requirements for substances such as switchgear oil. These procedures also mandate the prompt reporting of any uncontained spillage and disposal of hazardous substances, which allows us to document the details of spillage and disposal quantities.

We also have procedures for the environmental management and disposal of Sulphur Hexafluoride (SF_6).



Our power transformers installed at zone substations range from 2.5MVA to 60MVA.

6.12 Power transformers

6.12.1 Summary

Our power transformers installed at zone substations range from 2.5MVA to 60MVA. Our oldest transformers are ex-Transpower single phase transformers, which we plan to replace in this AMP period due to their age and condition. We have forecast to refurbish several power transformers over the AMP period to ensure they continue their reliable service in the future.

Our oldest transformers are the ex-Transpower single phase transformers, which we plan to replace in this AMP period due to their age and condition.

6.12.2 Asset description

Transformer

Power transformers are installed at zone substations to transform subtransmission voltages of 66kV and 33kV to a distribution voltage of 11kV. They are fitted with on-load tap changers and electronic management systems to maintain the required delivery voltage on the network. All our transformer mounting arrangements have been upgraded to current seismic standards, and all transformers have had a bund constructed to contain any oil spill that may occur.

Table 6.12.1 Power transformer quantities by type

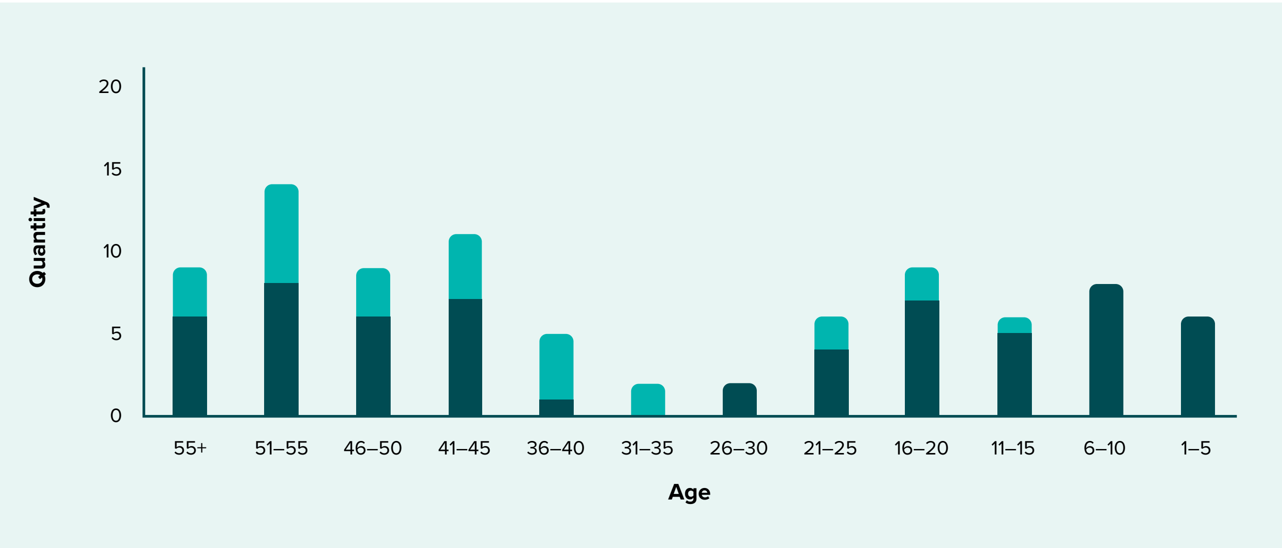
Nameplate Rating MVA	66kV	33kV
	Quantity	Quantity
30/60	2	
34/40	2	
30/36 (1Ø Banks)	2 (6)	
20/40	29	
20/30	2	
11.5/23	13	7
10/20		4
7.5/10	6	8
7.5		7
2.5		1
Total	**56 (60)**	**27**

6.12 Power transformers continued

Our power transformer age profile is shown in Figure 6.12.1. The useful life of a transformer can vary greatly. Our transformers often operate well below their nominal capacity which can lengthen their effective operating life.

We test and maintain our power transformers annually to ensure satisfactory operation. Some transformers are also refurbished to ensure we achieve the expected asset life of at least 55 years. Some of our older transformers are scheduled for replacement later in this AMP period – see Section 6.12.5.

Figure 6.12.1 Power transformer age profile



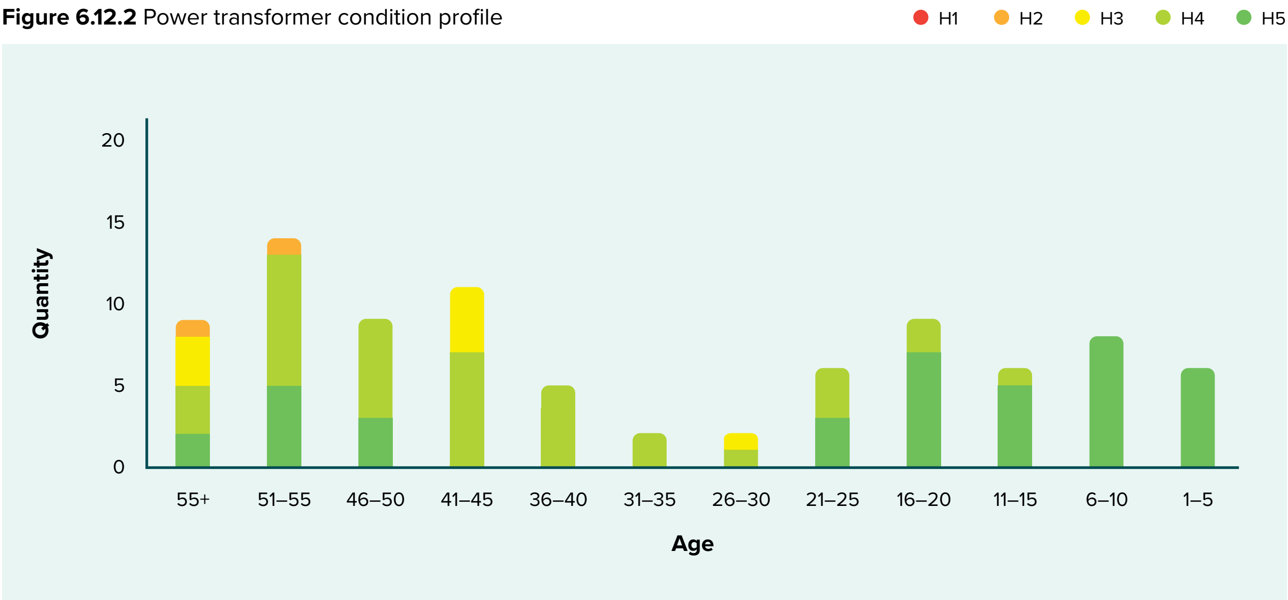
6.12.3 Asset health

6.12.3.1 Condition

Power transformers

Our inspection and maintenance program informs us that most of our power transformers are in good serviceable condition. We are aware of some transformers with issues such as moderate oil leaks and external condition deterioration. For our strategy to address these issues, see Sections 6.12.4 and 6.12.5.

Figure 6.12.2 Power transformer condition profile



6.12.3.2 Reliability

We design for N-1 power transformer capability in most situations and plan to attain a high level of reliability and resilience from this asset. The contribution of SAIDI from these assets is very low indicating that broadly, our current inspection, maintenance, and renewal strategies are effective. We continue to assess defects and failures to continually improve our maintenance practices.

6.12.3.3 Issues and controls

Table 6.11.3 lists the common causes of failure and the controls implemented to reduce their likelihood.

We design for N-1 power transformer capability in most situations and plan to attain a high level of reliability and resilience from this asset.

Table 6.12.2 Power transformer issues and control measures

Common failure cause	Known issues	Control measures
Insulation failure	Heat	Transformers are normally operated substantially below their maximum thermal capability. Transformer temperatures are monitored Testing of oil in the transformer is used to determine paper degradation New transformers have thermally uprated papers
	Moisture	Regular monitoring of the moisture in the oil Condition the oil to remove moisture (Trojan machine)
	Lightning	Surge arrestors fitted to overhead lines and switchyards
Mechanical failure	Tap changer	We specify vacuum tap changers for new power transformers as they are essentially maintenance free Oil tap changers are regularly maintained
Material degradation	Corrosion	Routine inspections and maintenance programme The tank and cooling fins are repainted as part of the refurbishment programme
	Deterioration of enclosure gaskets can lead to moisture ingress	Gaskets are replaced in refurbishment programme

6.12.4 Maintenance plan

Our maintenance activities shown in Table 6.12.4 are driven by a combination of time-based inspections and reliability centred maintenance.

Table 6.12.3 Power transformer maintenance plan

Maintenance activity	Strategy	Frequency
Inspection	Minor visual inspection and functionality check	2 months
Shutdown service	Detailed inspection and functional check	Annual
Oil diagnostics	DGA and oil quality tests	Annual
Oil treatment	Online oil treatment to reduce moisture levels	2 years or more often as required
Tap changer maintenance	Intrusive maintenance and parts replacement as per manufacturer's instructions	4 years for oil 8 years for vacuum
Level 1 and 2 electrical diagnostics	Polarisation index and DC insulation resistance DC Winding resistance, winding ratio test	4 or 8 years

6.12.4.1 Power transformer refurbishment

Our programme for the refurbishment of ageing transformers ensures we achieve the expected life of the asset. Where it is economic, we carry out half-life maintenance of power transformers to extend their working life and in doing so we improve service delivery and defer asset replacements. This efficiency improvement delivers on our asset management strategy focus on operational excellence. Our customers benefit from our prudent asset management through assurance of service delivery and deferred investment.

The annual forecast of power transformer and regulator operational expenditure in the Commerce Commission categories is shown in Table 6.12.5. Our forecasts are based on our assessment of transformer age, condition, and technical and financial feasibility.

Table 6.12.4 Power transformer operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Routine and corrective maintenance & inspection	370	290	320	300	300	300	320	300	300	310	**3,110**
Asset replacement and renewal	23	390	673	600	300	-	-	-	-	-	**1,985**
Total	**393**	**680**	**993**	**900**	**600**	**300**	**320**	**300**	**300**	**310**	**5,095**

6.12.5 Replacement plan

Our current replacement programme targets end of life zone substation power transformers. The programme as shown in Table 6.12.6 prevents failure rates and risk from materially increasing above current levels.

Table 6.12.5 Power transformer replacement plan

Zone substation	Details	Financial year planned
Addington	Replace T6 and T7 transformer banks. This transformer replacement timing is dependent on a wider network and site strategy to rationalise assets at the substation	FY25/FY26

Figure 6.12.4 shows the current condition and 10-year condition projection for the two scenarios. 'Do nothing' is a hypothetical scenario where no transformers are proactively replaced or refurbished. This unrealistic scenario is provided as a benchmark to assist in visualising the benefits of the proposed programmes. The 'planned renewals' is a targeted intervention that takes into account the asset's condition and the timing of other related works to produce efficient and economic outcomes.

Figure 6.12.3 Power transformer health scenarios

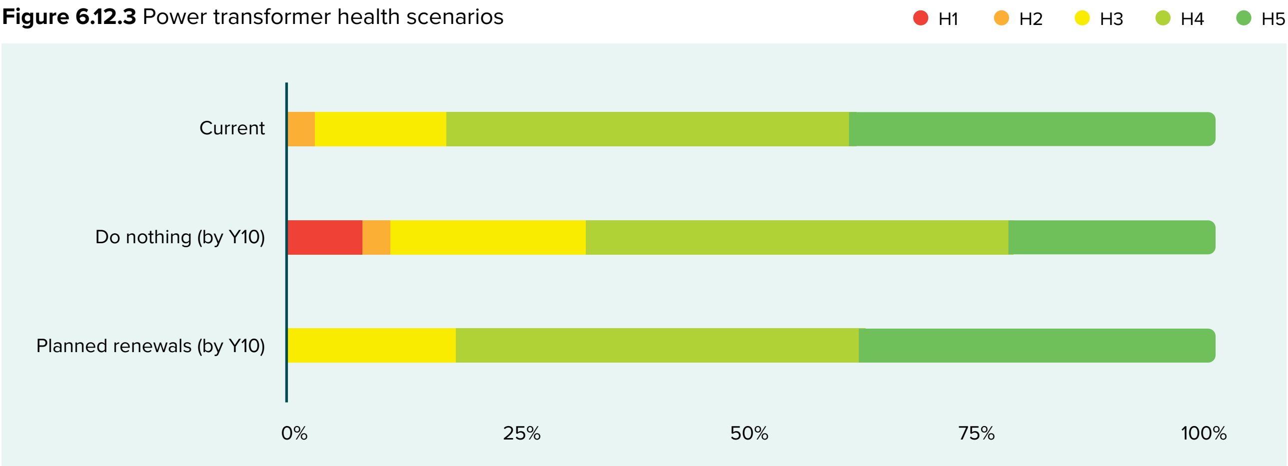
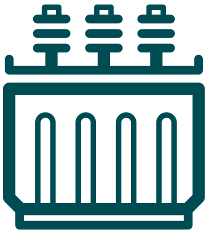


Figure 6.12.4 shows that the planned renewal scenario improves the overall condition scores of our transformer fleet. This is due to our ongoing refurbishment programme and replacement of our end of life single phase transformers. Comparing with the 'do-nothing' scenario shows that the proposed programme mitigates a substantial deterioration in asset condition. An annual summary of power transformer capital expenditure in the Commerce Commission categories is shown in Table 6.12.7. The forecast has been established from a bottom up approach to ensure sufficient detail of costing was captured.

Table 6.12.6 Power transformer replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Zone substation	-	3,450	2,846	-	-	-	-	-	-	-	**6,296**
Total	**-**	**3,450**	**2,846**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**6,296**



We have more than 11,000 distribution transformers installed on our network to transform the voltage from 11kV to 400V for customer connections.

6.13 Distribution transformers

6.13.1 Summary

We have more than 11,000 distribution transformers installed on our network to transform the voltage from 11kV to 400V for customer connections. They range in capacity from 5kVA to 1,500kVA. The performance of our distribution transformer fleet is meeting our expectations. We continue to maintain and replace our distribution transformers in accordance with our standard asset management practices.

6.13.2 Asset description

This section details the following asset fleet categories:

- Pole mounted and ground mounted distribution transformers
- Other voltage support assets including regulators, static synchronous compensators and capacitor banks.

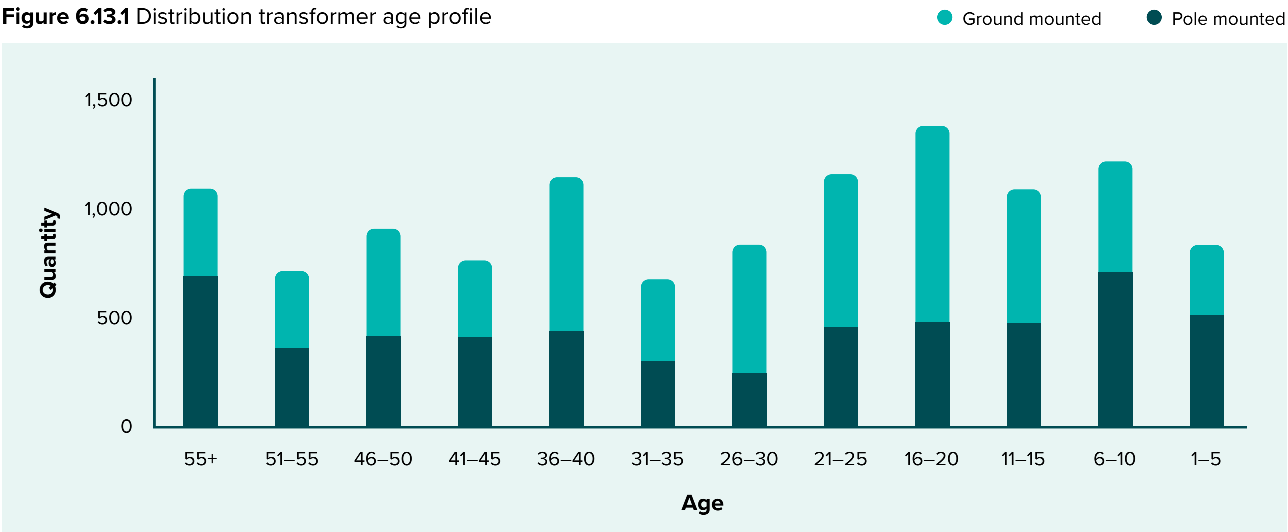
Pole mounted transformers range in rating from 15kVA – 300kVA. There is a small population of Single Wire Earth Return (SWER) pole transformers used to economically supply small remote loads less than 75kVA. With new installations we limit pole-mount transformers to no bigger than 200kVA for safety reasons.

Ground mounted transformers range in rating from 5kVA to 1,500kVA. These are installed either outdoors or inside a building/kiosk. Table 6.12.1 shows the transformer quantities categorised by rating, and an age profile can be found in Figure 6.13.1.

Table 6.13.1 Distribution transformer quantities by type

Rating kVA	Ground mount	Pole mount
	Quantity	Quantity
5-100	570	5,938
150-500	4,419	380
600-1000	634	
1250-1500	32	
Total	**5,655**	**6,318**

Figure 6.13.1 Distribution transformer age profile



Voltage Support

11kV line voltage regulators are installed at various locations to provide capacity via voltage regulation. We use a wide range of ratings to cater for different load densities within our network. All regulators are oil-filled, with automatic voltage control by an on-load tap changer or induction. Other assets on our network that provide reactive voltage support include capacitor banks and Static Synchronous Compensators (Statcom). Statcoms can provide continuously variable voltage support response.

Table 6.13.2 shows the voltage support asset quantities categorized by rating, and an age profile can be found in Figure 6.13.2.

Table 6.13.2 Voltage support assets quantities by type

Asset type	Rating	Quantity
Regulator	1,000 – 4,000kVA	12
	20,000kVA	3
Voltage support capacitor	500 – 750VAr	6
Statcom	2,500kVAr	4

Figure 6.13.2 Voltage support age profile

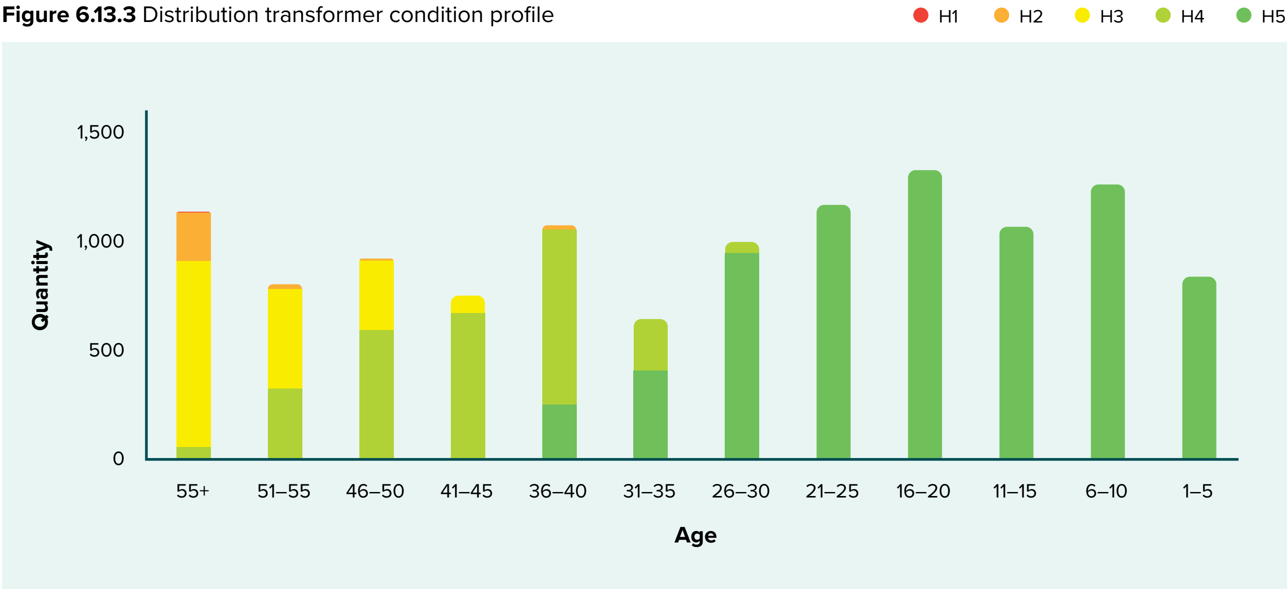
6.13.3 Asset health

6.13.3.1 Condition

As it can be seen in Figure 6.13.3 our ground mounted distribution transformers are in serviceable condition and are inspected on site every six months. The condition of the pole-mounted transformers varies depending on their age and location. They are only maintained, if this is considered appropriate, when removed from service for other reasons.

Our ground mounted distribution transformers are in serviceable condition and are inspected on site every six months.

Figure 6.13.3 Distribution transformer condition profile



6.13.3.2 Reliability

In general, distribution transformers are very reliable and they are performing to our expectations. The failure rate and contribution to SAIDI/SAIFI by distribution transformers is very low which indicates that broadly, our current inspection, maintenance, and renewal strategies are effective.

6.13.3.3 Issues and controls

Pole transformers have a higher failure rate than ground mounted transformers due to their constant exposure to the environment, especially lightning. As it is uneconomic to routinely test and maintain pole transformers in service, and as safety and customer impact consequences are low, running to failure can be tolerated. Most of our ground mounted transformers are in an inspection program, and visual condition cues can initiate remedial maintenance.

Table 6.13.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 6.13.3 Distribution transformer failure controls

Common failure cause	Known issues	Control measures
Insulation failure	Heat	Maximum load of larger ground mount transformers are routinely checked and replaced if overloading occurs
	Lightning	Surge arrestors fitted at cable terminations to the lines protect ground mount transformers
Material degradation	Moisture ingress due to deterioration of enclosure seals Corrosion	Inspection, maintenance and replacement programme

6.13.4 Maintenance plan

Our maintenance activities are driven by a combination of time-based inspections and reliability centred maintenance. Ground mount transformers receive regular inspections to ensure safe and reliable operation of our assets. Some on-site maintenance is carried out on transformers which are readily accessible from the ground. This work mainly relates to those within building substations that require maintenance as identified during inspection programmes.

With the exception of the building substation transformers, distribution transformers are normally maintained when they are removed from the network for loading reasons or substation works. Their condition is then assessed on a lifecycle costs basis and we decide, prior to any maintenance, whether it would be economic to replace them. If we decide to maintain them they will be improved to a state where it can be expected the transformer will give at least another 15 to 20 years of service without maintenance. This maintenance programme is shown in Table 6.13.4.

Table 6.13.4 Distribution transformer maintenance plan

Maintenance activity	Strategy	Frequency	
		Pole mount	Ground mount
Inspection	Visual inspection checking for damage to the transformer including cracked or damaged bushings, corrosion, unsecured covers, signs of oil leakage, paintwork. Minor repairs to ground mount transformers as necessary	5 years	6 months
Maintenance	Maintenance as required	As required	As required
Regulator	Detailed inspection and maintenance of internals. Inspect and maintain tap changer. Functional test of control circuits. Test insulation resistance test oil and treat for acidity and carbon build up		6 monthly inspection 4 yearly maintenance
Capacitor banks	No specific inspection rounds. Maintenance as required.		As required
Statcom	Annual inspection and maintenance provided by manufacturer		Annual Maintenance

6.13 Distribution transformers continued

An annual forecast of our operational expenditure on distribution transformers in the Commerce Commission categories is shown in Table 6.13.5. Note that the forecast for emergencies also includes servicing power transformers and regulators.

Table 6.13.5 Distribution transformer operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	180	180	180	180	180	180	180	180	180	180	**1,800**
Routine and corrective maintenance and inspections	460	460	460	460	460	460	460	460	460	460	**4,600**
Total	**640**	**640**	**640**	**640**	**640**	**640**	**640**	**640**	**640**	**640**	**6,400**

6.13.5 Replacement plan

Transformers taken out of the network due to capacity increase or faults are replaced where repair or maintenance proves uneconomic. The budget for this is based on unit cost applied to the expected replacement rate. Approximately 13% of the current distribution transformer fleet is going to reach end of life in the next 10 years. Therefore, the amount of distribution transformer replacements is expected to increase slightly over the AMP period, as older unit become less economic to repair. Expenditure has also been allocated to replace faulty ferroresonant capacitor banks over the next 10 years.

We have three 20MVA regulators located at Heathcote zone substation that are required for contingency support voltage to Barnett Park zone substation and Lyttleton township. These regulators are more than sixty years old.

Two units have previously been refurbished, but recent routine maintenance discovered deterioration of the tap changer assembly in one of these units. Due to their age and condition, we are investigating end of life solutions for later in the 10 year plan. An annual summary of our distribution transformer replacement capital expenditure in the Commerce Commission categories is shown in Table 6.13.6.

Table 6.13.6 Distribution transformer replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Distribution substations and transformers	1,620	1,490	1,870	2,275	3,075	3,075	2,275	2,275	2,275	2,275	**22,505**
Total	**1,620**	**1,490**	**1,870**	**2,275**	**3,075**	**3,075**	**2,275**	**2,275**	**2,275**	**2,275**	**22,505**

6.13.5.1 Disposal

Our network specification for distribution transformer maintenance mandates the disposal of transformers where they are beyond economic repair. The recommendation to dispose is made by our service providers and must be approved by Orion.

Protection systems are installed to provide automatic control to elements of our network and to protect it during power system faults.

6.14 Protection systems

6.14.1 Summary

Our protection system consists of Intelligent Electronic Devices (IED), electromechanical relays and analogue electronic devices. Overall our protection system equipment is performing well and meeting our service target levels.

The main issues are due to asset ageing or obsolescence in equipment support, parts and function.

The reliability of the protection system is inherent in fulfilling our objectives of maintaining personnel safety and system reliability.

Protection system upgrades/replacement is most cost effective if linked to the associated switchgear replacement. For this reason, our protection system replacement programme is influenced by the volume and schedule of our switchgear replacement.

6.13.2 Asset description

Protection systems are installed to provide automatic control to elements of our network and to protect it during power system faults. The protection relays we use on our network are either electro-mechanical devices, or modern microprocessor-based intelligent electronic devices (IED). IEDs provide protection, control and metering functions integrated into a single device. The introduction of IEDs has allowed us to reduce costs by improving productivity and increasing system reliability and efficiency.

Table 6.14.1 Relay types

Relay type	Quantity
Electro-mechanical	1,017
Micro-processor based (IED)	1,762
Total	**2,779**

6.14.3 Asset health

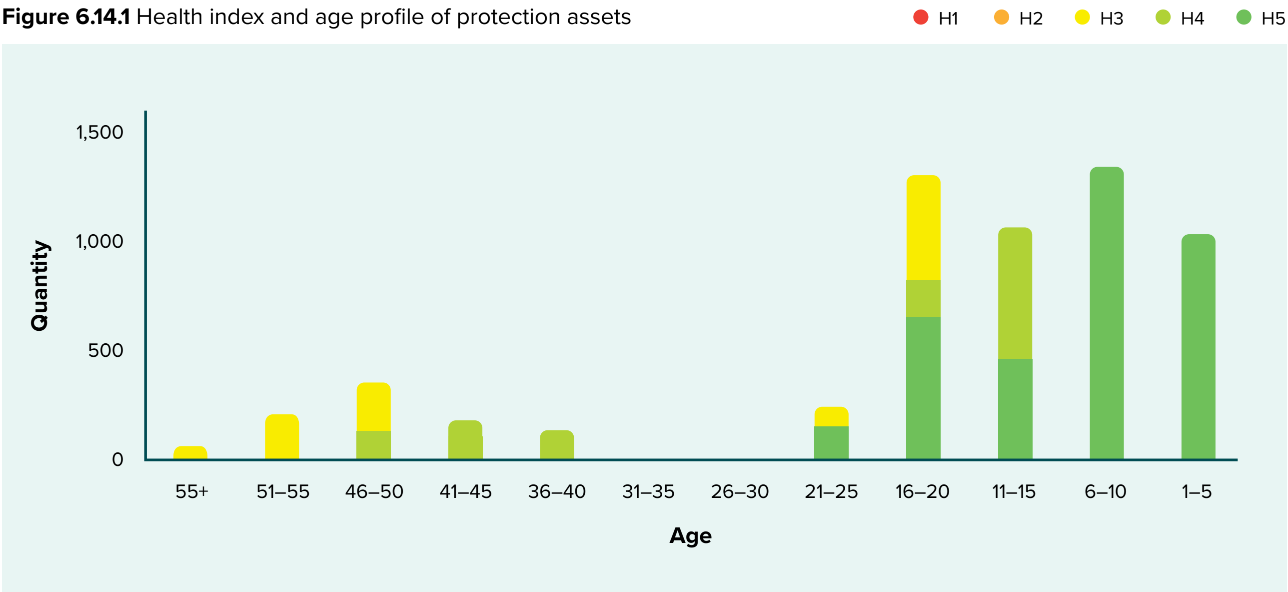
6.14.3.1 Condition

The factors that go into evaluating the protection relay health index are predominately the age but also include make/model reliability and obsolescence factors. Figure 6.14.1 shows the health index profile against the age of our protection assets.

The health profile shows that most of the protection relay population is healthy. A smaller proportion of our population have health indices in the 'H3' range. This reflects the phase of their life when the probability of failure is increasing and requires active consideration of their replacement. These 'Fair' health index relays are mostly types with known problems or ageing electromechanical types.

We believe the levels we are achieving are appropriate as Orion is delivering on its asset management objectives and service level targets. Our intention with our maintenance and replacement programmes is to maintain our current asset condition and service levels.

Figure 6.14.1 Health index and age profile of protection assets



6.14.3.2 Reliability

Overall, Orion's protection systems are meeting our asset management objective to protect people and assets and to avoid unintentional outages due to protection system failure.

Our older electromechanical relays are still performing satisfactorily. This technology is employed in short urban feeders that require relatively simple protection functions. The risks from failures are low due to these segments of the network having good backup supply and protection. However, as the associated switchgear comes to the end of its service life we take the opportunity to replace these relays with more advanced modern systems.

Overall our IED relays are performing well. The main issue with our protection system is around the ageing or obsolescence of equipment, support, parts and function. As the relays age, their reliability diminishes.

6.14.3.3 Issues and controls

Protection failure can lead to longer fault durations with further potential for asset damage, larger outages and injury to our people and the public. Protection failure can also cause spurious tripping leading to unwanted isolation of circuits impacting our reliability. Table 6.14.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 6.14.2 Protection system failure controls

Common failure cause	Known issues	Control measures
Electrical failure	Ageing	Repair if economical and product still supported by manufacturer or spares available. If not, replacement is the only option
	Loose wiring and termination	Regular inspection and testing
Functional failure	Ageing and obsolescence	Repair if economical and product still supported by manufacturer or spares available. If not, replacement is the only option
	IED hardware, firmware and software failure	Most IEDs are self-testing and SCADA monitored. Failures do not normally impact network reliability as repairs are carried out immediately under emergency maintenance. Repairs may be as simple as resetting the relay or replacing the failed components. Firmware upgrades can also resolve some known issues. Regular inspection can pick up non-SCADA connected relay issues
Mechanical failure (especially electromechanical relays)	Ageing and obsolescence	Repair if economical and product still supported by manufacturer or spares available. If not, replacement is the only option
	Vibration or drift out of set point	Regular testing and calibration
Chewed cables	Pest and vermin	We have vermin proofed building entries and installed vermin traps in zone substations

6.14.4 Maintenance plan

We carry out regular inspections of our protection systems including a visual inspection, display and error message checking and wiring and termination conditions. Protection systems are checked for calibration and operation as part of the substation maintenance/testing rounds.

The frequency of inspection and maintenance/testing of our protection system is dependent on the location.

The frequency of zone substation maintenance is typically set by the installed primary asset type's insulation medium within the circuit breakers and power transformer tap changer. IED protection systems, which are generally paired to vacuum circuit breakers are thoroughly tested and maintained every eight years. Older generation protection systems which are paired to oil circuit breakers are tested and maintained every four years. Protection systems that interact with GXP protection systems are tested every four years. The frequency of inspection and maintenance by location is shown in Table 6.14.3.

6.14 Protection systems continued

Table 6.14.3 Protection maintenance plan

Location	Task	Frequency
Zone substations	Inspection – check relay flags	2 months
	Protection testing	4 or 8 years
Distribution substations	Inspection – check relay flags	6 months
	Protection testing	8 years
Line circuit breaker	Inspection – check relay flags	Annual
	Protection testing	8 years
All 11kV trunk feeder sites	Unit protection testing	4 years

Based on analysis of failure rates, efficiency of fault detection and maintenance service provider costing, we forecast a stable ongoing option for maintenance work volume similar to our previous years. An annual forecast of operational expenditure on protection systems is shown in Table 6.14.4 in the Commerce Commission categories.

Table 6.14.4 Protection operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	175	175	175	175	175	175	175	175	175	175	**1,750**
Routine and corrective maintenance and inspections	440	440	450	450	455	455	460	460	465	465	**4,540**
Total	**615**	**615**	**625**	**625**	**630**	**630**	**635**	**635**	**640**	**640**	**6,290**

6.14.5 Replacement plan

When we replace protection systems, we review options around the best device to use, their function, standardisation of design and how it fits into the immediate network.

Although we use the CBRM model to help guide our protection system replacement, a large portion of our relay replacements are still linked to our switchgear replacement programme. Replacement in conjunction with end of life switchgear is economical and efficient in terms of cost and timing for outages. This is especially true for our ongoing work of migrating our older electromechanical devices to modern IEDs. The timing for replacement of our older IED relays does not necessarily coincide with the associated switchgear as IEDs have a lifecycle of 15-20 years compared to a lifecycle of 50 years for switchgear.

Where 1st generation IEDs are due for replacement at zone substations we upgrade the protection to our current standards and install arc flash detection. This reduces the risk of asset damage and injury to our staff and contractors. The timing can also coincide with any other related work to be undertaken at those sites to reduce outages and more efficient usage of contracting resources.

The forecast replacement expenditure in the Commerce Commission categories is shown in Table 6.14.5.

Table 6.14.5 Protection capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Zone substation	1,738	605	1,910	1,590	1,820	1,690	1,790	1,790	2,900	1,890	**17,723**
Distribution switchgear	153	309	363	477	286	305	300	300	300	300	**3,093**
Total	**1,891**	**914**	**2,273**	**2,067**	**2,106**	**1,995**	**2,090**	**2,090**	**3,200**	**2,190**	**20,816**

Our 1,078km of communication cables are predominantly multi-twisted-pair cables located in Region A.

6.15 Communication cables

6.15.1 Summary

Communication cables are primarily used for SCADA, ripple control, metering and other purposes in addition to their original function of providing unit protection communications. The majority of these cables are fit for purpose however some copper twisted-pair communication cables are running out of pairs due to joint failures. We do not have a proactive replacement plan, and cable joints are repaired as required. The majority of our existing communications cables are multi-twisted-pair copper which is an older communications technology. When we require new communications routes associated with subtransmission cables or lines we now generally install fibre optic cables in ducts.

When we require new communications routes associated with subtransmission cables or lines we now generally install fibre optic cables in ducts.

6.15.2 Asset description

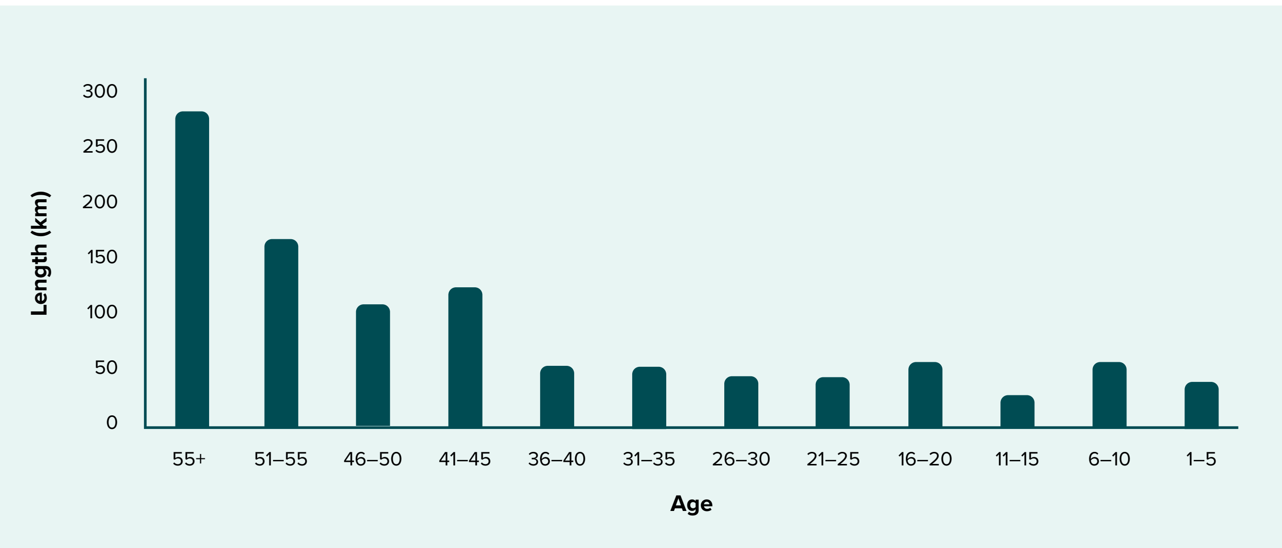
Our 1,078km of communication cables are predominantly multi-twisted-pair copper cables located in Region A. Most are armoured construction. They are laid to most building substations and are used for Unit Protection communications (pilot wire), SCADA, telephone, data services, ripple control and metering.

We install fibre optic communications cables, laid in ducts with all new subtransmission power cables. We also share Transpower's existing fibre-network ducts which provide us with fibre routes between our Control Centre at 565 Wairakei Rd and our zone substations. These fibre routes provide both protection signalling for various 66kV circuits, plus SCADA and other data communications.

The most common and effective differential protection uses multi-twisted-pair communication cables for end-to-end measurement of electrical parameters on the protected section of cable. As new lengths of primary network cable are laid, a communication cable is laid with the electrical power cable.

The age profile of our communication cables is shown in Figure 6.15.1. The average age of these cables is 42.

Figure 6.15.1 Communication cables age profile



6.15.3 Asset health

Our copper communication cables are of advanced age, fault finding and repairs are uneconomic at times. A common failure point on the copper twisted-pair communication cables is the joints. These joints are epoxy filled and have two modes of failure, they are:

- The epoxy used in the old filled joints overtime becomes acidic and eats away the crimp joints leaving the cables open circuited
- Ground movement allows moisture ingress due to the inflexible nature of the epoxy.

6.15.4 Maintenance plan

No specific maintenance plan is employed for the communication cables at this stage, but circuits that are used for Unit Protection communication are routinely tested. Any identified issues are addressed as part of protection maintenance at this stage.

A forecast of the annual operational expenditure on our communication cables in the Commerce Commission categories is shown in Table 6.15.1.

Table 6.15.1 Communication cables operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	20	20	20	20	20	20	20	20	20	20	**200**
Routine and corrective maintenance & inspection	80	80	80	80	80	80	80	80	80	80	**800**
Total	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**1,000**

6.15.5 Replacement plan

Our approach to replacement of communication cables is mostly reactive. To minimise the risk of failure, alternative communication paths are maintained and renewal work is planned accordingly. Some renewal work on communication cables is based on condition results from tests carried out during the installation and commissioning of other works.

The expenditure is currently volatile due to this reactive nature of replacement so our budget is based on a historical average. The replacement expenditure in the Commerce Commission categories is shown in Table 6.15.2.

Table 6.15.2 Communication cables replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Other network assets	80	80	80	80	80	80	80	80	80	80	**800**
Total	**80**	**80**	**80**	**80**	**80**	**80**	**80**	**80**	**80**	**80**	**800**

Our communication systems enable us to operate our network and deploy our people efficiently, and help us to reduce the impact of faults on customers.

6.16 Communication systems

6.16.1 Summary

Our communication network is made up of voice and data systems which provide an essential ancillary service assisting with the operation of our distribution network, and communication with our customers. These systems provide contact between our Control Room and operating staff and service providers in the field, and remote indication and control of network equipment. Our communication systems enable us to operate our network and deploy our people efficiently, and help us to reduce the impact of faults on customers.

These systems are in serviceable condition and performing well. Additional control of the high voltage network and monitoring of the low voltage network is taking place. We have started to upgrade our analog radios to digital. This will provide us with significantly increased signal coverage in remote areas of the network.

Additional capital expenditure has been put in place from FY28 onwards to strengthen our communication network across our operating region. These projects will provide safety benefits to our service providers by improving communication connectivity.

We have started to upgrade our analog radios to digital. This will provide us with significantly increased signal coverage in remote areas of the network.

6.16.2 Asset description

6.16.2.1 Voice communication system

Our voice communication system is made up of three different sub-systems:

- **VHF analogue radio** – installed in vehicles and hand-held portable units. These operate via Linked VHF hilltop radio repeaters. We will migrate these to digital once the backbone infrastructure is in place.
- **Private telephone switch** – a telephone network split between the transportable data centres, connecting to the main telco network from both locations.
- **Public cellular networks** – not owned by Orion, we use these public networks for mobile voice and data communications.

  To increase resilience, our office cellular site is directly connected to the Christchurch cellular switching node.

6.16.2.2 Data communication system

Our data communication system is made up of five different network or sub-systems providing data communications to network field assets, protection for main power feeds and general data communications to business mobile devices. These systems along with a description of each can be found in Table 6.16.1.

Table 6.16.2 shows the quantities of these assets by type.

Table 6.16.1 Data communication systems description

Asset	Expected asset life
SCADA analogue communication copper cable network	Used for serial communication to a small number of urban substations. Installed in dedicated pairs with one modem at the remote site connected to a remote terminal unit (RTU) and its pair at a zone substation connected to the Internet Protocol (IP) network via terminal servers. This system is due for replacement due to obsolescence
SHDSL IP system	Used for point-to-point IP links and protection between substations utilising private copper communications where available. Various urban links are arranged in four rings to provide full IP communication redundancy to each substation. This system is fully protected against Earth Potential Rise (EPR) voltages
UHF IP and protection radio system	Utilise high spectral efficiency radios operating in licensed UHF bands. These radios are used for point-to-point and point- to-multipoint where they utilise base stations located at hilltop sites
Fibre communications system	Provide IP and protection signaling. Fibre is typically laid with all new sub-transmission cables and provides high speed communications paths between our SCADA, engineering network IP and corporate office
Public cellular network	Operated with in a private access point name (APN) gateway provided by commercial providers. A number of our 11kV regulators, diesel generators, pole top switches and reclosers and various power quality monitors are connected to this system. This network also supports all our mobile devices and data connectivity to our vehicles

Table 6.16.2 Communication component quantities by type

Asset	Quantity
Cable modems	349
Voice radios	400 (includes Orion service providers')
Cellular modems/HH PDA's	377
IP data radios	347
Radio antennae	347
Antenna cable	550
Communication masts	55
Routers/switches	56
Telephone switch	2

6.16.3 Asset health

6.16.3.1 Condition

Our IP based equipment is on average no older than eight years and performing well. We have replacement programmes in place to replace technologies nearing the end of life.

6.16.3.2 Reliability

The SCADA IP network is very fault tolerant and can in many cases withstand multiple link failures without losing significant connectivity. This is because we have configured it in a mix of rings and mesh with multiple paths to almost all zone substations and major communications nodes.

6.16.3.3 Issues and controls

Table 6.16.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 6.16.3 Communication systems failure controls

Common failure cause	Known issues	Control measures
Infrastructure component failure	Malicious damage (arson, shooting antennae) Weather damage (rain, wind, snow) Lightning strike Power supply failures on radio units and base stations	Resilient infrastructure and lifecycle management Diversity of data/signal paths (rings) Octal Small Pluggable Format (OSPF) routing protocol (functional self-healing) Spares
	Human error	Training / certification Change Management
Systemic failure	Interference from third party equipment	Diversity of data/signal paths (rings) OSPF routing protocol (functional self-healing) Use of Licensed spectrum
	Rogue firmware updates	Device passwords Change management / testing
Cyber security threats	Because of the use of industry standard hardware and protocols, the external IP network is exposed to Cyber Security threats which include the possibility of unauthorised persons accessing the communication network from a substation and remotely operating, or modifying the settings, of equipment at other substations	To mitigate this risk we have configured communication firewalls at zone substations and installed a centralised security system which logs and controls access to the network
Reliance on public cellular providers	Our experience is that the public providers have different business drivers than our own when operating in a Disaster Recovery mode	We closely monitor developments in private cellular network technology and other developments in this communication space

6.16.4 Maintenance plan

Regular inspections are carried out to ensure reliable operation of the communication systems. The plan is described in Table 6.16.4 and the associated expenditure in the Commerce Commission categories is shown in Table 6.16.5.

Table 6.16.4 Communication systems maintenance strategy

Asset	Maintenance activities / strategy	Frequency
Cable modems	No preventative maintenance, replaced if faulty, SHDSL modems are continuously monitored with faults attended to as soon as detected The serial modems are being replaced by Ethernet SHDSL modems	As required
Voice radios	No preventative maintenance, replaced if faulty	As required
Cellular modems / HH PDAs		
IP data radios	The performance of our UHF stations used to communicate with the SCADA equipment is continually monitored with faults attended to as soon as detected	As required
Radio antenna	No preventative maintenance, replaced if faulty, radio links are continuously monitored with faults attended to as soon as detected	As required
Antenna cable		
Communication masts	Visual inspection as part of substation inspection Targeted inspections are performed on masts affected by the effect of winds in the lee of mountains, the lee air effect	2 months Annually
Routers / switches	No preventative maintenance, replaced if faulty, links are continuously monitored with faults attended to as soon as detected	As required
Telephone switch	We have maintenance contracts with several service providers to provide on-going support and fault resolution. A 24x7 maintenance contract for the telephone switch is in place	Monthly

Table 6.16.5 Communication systems operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	35	35	35	35	35	35	35	35	35	35	**350**
Routine and corrective maintenance and inspections	634	614	545	545	545	545	545	545	545	545	**5,608**
Total	**669**	**649**	**580**	**580**	**580**	**580**	**580**	**580**	**580**	**580**	**5,958**

6.16.5 Replacement plan

Due to the rapid improvement in technology, communications equipment has a relatively short life and equipment is usually replaced with more modern technologies. Our communication systems renewal programmes use an age based approach however, the timing of programmes is governed by asset obsolescence and the availability of spares and support. Our replacement plan over the AMP period is shown in Table 6.16.6 and the forecast expenditure in the Commerce Commission's categories is in Table 6.16.7.

Table 6.16.6 Communication systems replacement plan

System	Replacement plan
Completion of IP Network	We are progressively upgrading older analogue links when the associated network primary equipment is replaced. Additional IP radios were installed as part of protection improvements on the Banks Peninsula 33kV ring to provide alternative communication links to the peninsula
Voice radios	After the successful trial of a digital radio system on the Banks Peninsula in FY20, we are continuing to migrate our existing analog system over the next two years. The upgrade will significantly increase our coverage in remote areas and offer more features such as user identification and user location
Comms architecture projects	As we introduce new assets on our network the need for communications increases. Expenditure is allocated for such projects, with the majority going towards fibre installations. Currently there is no long-term plan for our communications architecture projects and fibre installations are planned with other works to keep the costs down.
Future projects	From FY28 onwards, we plan to roll out additional projects to strengthen our communication network across our operating region. These projects will provide safety benefits to our service providers by improving communication connectivity. The exact timing of these projects will be finalised as requirements become clearer to us closer to the time. Some of the proposed projects are: • More mobile bandwidth outside cellular coverage • Dual communications routes for major sites • Additional hilltop communication hubs

Table 6.16.7 Communication systems replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Other network assets	1,147	1,013	487	558	1,462	1,896	2,014	1,737	1,837	1,810	**13,961**
Quality of supply	60	60	258	258	103	103	103	103	103	103	**1,254**
Total	**1,207**	**1,073**	**745**	**816**	**1,565**	**1,999**	**2,117**	**1,840**	**1,940**	**1,913**	**15,215**

Due to the rapid improvement in technology, communications equipment has a relatively short life and equipment is usually replaced with more modern technologies.

Safety is a core driver for the use and development of our data management systems.

6.17 Advanced Distribution Management System (ADMS)

6.17.1 Summary

Our Advanced Distribution Management System (ADMS) is built on a digital model of our high voltage network and supports a range of activities related to the operation, planning and configuration of the electricity network. Safety is a core driver for the use and development of our advanced distribution management system. It is an essential element in our efforts to ensure the safe and effective operation of the network.

Our ADMS enables automated control and management of our electricity network and directly supports reliability measures such as SAIDI and SAIFI.

The network model used by our digital ADMS and the SCADA data it relies on are currently limited to high voltage assets of 11kV or more. Over the next five years we will extend the model to include low voltage assets. We will also introduce technology that will enable the ADMS to automatically operate network equipment or self-heal to restore supply to customers following an outage.

6.17.2 Asset description

An ADMS is a suite of applications designed to monitor and control the distribution network and also to support decision making in the Control Centre. Our future planning for our ADMS includes the installation of more remotely controlled switchgear and the use of the existing on-line load-flow analysis which enables the implementation of an Adaptive Power Restoration System (APRS). APRS allows the ADMS to autonomously operate remote switching devices to isolate faults and reconfigure the network to restore supply. This significantly reduces restoration times after faults occur on the network. We will implement the online release request system to improve service provider workflow.

The network model used by our digital ADMS and the SCADA data it relies on are currently limited to high voltage assets 11kV or more. Over the next five years we will extend the model to include low voltage assets.

6.17 Advanced Distribution Management System (ADMS) continued

Table 6.17.1 ADMS description

System component	Description
	Core systems
SCADA	A comprehensive SCADA master station is tightly integrated into the ADMS and provides telemetered real-time data to the network connectivity model
Network management system (NMS)	At the heart of the ADMS is a comprehensive, fully connected network model (including all lines, cables switches and control devices, etc.) that is updated in real time with data from network equipment. The model is used to manage the network switching processes by facilitating planning and scenario development, applying safety logic and generating associated documentation. It also maintains history in switching logs
Outage management system (OMS)	The OMS supports the identification, management, restoration and recording of all outage information. It assists in determining the source of interruptions by matching individual customer locations (from fault calls) to network segments and utilising predictive algorithms Customer details are recorded against faults in the OMS which allows our Contact Centre to call customers back after an interruption to confirm that their power supply has been restored
Mobile field service management	Network Operators are equipped with iPads and receive switching instructions from the Controller directly via the ADMS. The network model is immediately updated to reflect physical changes as switching steps are completed and confirmed on the iPad
Remote terminal unit (RTU)	The remote terminal unit is a field device that interfaces network objects in the physical world with the distribution management system SCADA master station
	Ancillary systems
Historian	The Historian is a database that records time series data for future analysis. The time series data stored in the historian is used by various applications throughout the organisation for planning, network equipment condition analysis and for reporting network operating performance statistics such as reliability
Real-time load flow analysis	The ADMS has access to large amounts of real time field data and maintains a connectivity model making it possible to undertake near real time load flow calculations. Load flow analysis can be used to predict network operating conditions at locations where no telemetered data is available and can also carry out "what if" scenarios to predict the effects of modified network topologies and switching
Information interfaces	Not all information required for operations and planning activities is available from the ADMS. Linking ADMS records to data from other systems greatly enhances our capabilities in both these areas. ADMS data may be presented in reports or used to populate web pages for internal or customer information
Cyber risks	Incidents are escalating for control systems around the world. Improved authentication, better access controls, improved segmentation of networks and systems, improved patching and upgrade practices are all essential to a safer control systems

6.17.3 Asset health

6.17.3.1 Condition

Our ADMS is a critical system required to successfully run daily network operations. The supplier releases a new software version every few months with new capabilities and bug fixes. We review our ADMS system annually and do a risk assessment on our current version with key considerations of keeping system support, cyber security and enhanced capabilities offered by new releases. Our plan is to do more regular updates to stay current with the latest functionality, security and usability features.

We have a number of older RTUs in our network that are no longer supported by their manufacturer. We hold enough spares to cover these units for maintenance purposes and they are performing adequately. These units are progressively being replaced as we undertake other upgrades at the substations. The major RTU type used is at end of life and we are starting to replace them during substation maintenance rounds.

6.17.3.2 Reliability

Generally the ADMS system runs at or near 100% reliability. There are some current constraints around the ADMS testing and development environments which are being addressed within our operational budgets. This will improve our ability to test and trial changes to the ADMS and associated modules, streamlining our upgrade path and improving system resilience.

6.17.3.3 Issues and controls

Our maintenance and replacement programmes are developed to ensure the continuous availability of the ADMS. This includes building highly resilient systems, upgrading core software and infrastructure on a lifecycle basis and undertaking regular reviews of system capacity and performance. Table 6.17.2 describes the potential failure cause and mitigation controls.

Generally the ADMS system runs at or near 100% reliability.

Table 6.17.2 ADMS failure controls

Common failure cause	Known issues	Control measures
Infrastructure component failure	Server hardware and platform failure	Real time monitoring, diversity, resilient infrastructure, lifecycle management
	RTU failure	Spares available Emergency contract
Information System (application/database) failure	Software failure/flaw	System monitoring, diversity, resilient platforms, maintenance contracts
Unexpected usage errors	Unexpected use cases	Training, testing, small systems change, upgrades

6.17 Advanced Distribution Management System (ADMS) continued

6.17.4 Maintenance plan

Our first line of support for ADMS software and infrastructure is provided by our own people. A maintenance contract with the software vendor includes:

- a remote response capability for emergencies
- a fault logging and resolution service
- the software component of any upgrade or service patch release

Our forecast expenditure is comprised of support contracts and licensing costs based on our current and future projections of enhancements. The forecast expenditure in the Commerce Commission categories is shown in table below.

Table 6.17.3 ADMS operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	55	55	55	55	55	55	55	55	55	55	**550**
Routine and corrective maintenance and inspections	445	508	525	665	605	630	755	848	833	915	**6,729**
Total	**500**	**563**	**580**	**720**	**660**	**685**	**810**	**903**	**888**	**970**	**7,279**

6.17.5 Replacement plan

We have introduced Automated Power Restoration System (APRS) in our ADMS which will be fully functional in FY24. We also plan to add a Primary Outage Restoration Tool (PORT) and Historic Network Viewer in coming years. These enhancements will deliver faster restoration after faults and post fault analysis of the event. We are also reviewing our operational technology (OT) cybersecurity in FY24 and budget has been allocated to coming years to implement the findings of this review.

The expenditure in Table 7.17.4 supports our plans for major upgrades for our ADMS in FY24-FY27. The expenditure also allows for analytics, automated switching, an LV model and future developments to be integrated into the ADMS over the coming years.

Table 6.17.4 ADMS replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Zone substation	129	143	242	168	168	168	168	168	168	168	**1,690**
Other network assets	1,435	1,510	1,940	420	1,220	620	1,220	750	1,244	620	**10,979**
Total	**1,564**	**1,653**	**2,182**	**588**	**1,388**	**788**	**1,388**	**918**	**1,412**	**788**	**12,669**

Our load management systems control electrical loads by injecting frequency signals over the electricity network.

6.18 Load management systems

6.18.1 Summary

Orion's load management systems control electrical loads by injecting frequency signals over the electricity network. The system is made up of various electrical plant and hardware/software platforms.

Our investment plan for this asset class includes refurbishment of the hardware and software of the USI load management master station due to its age and the unavailability of operating system support.

6.18.2 Asset description

Our load management consists of two separate systems: Orion's load management system and the Upper South Island (USI) load management system, which Orion operates in collaboration with the seven other electricity distributers in the upper South Island. These systems are described in Table 6.18.1.

The primary use of both systems is to defer energy consumption and minimise peak load. This is achieved in two ways. Customer demand management load reduction and/or generation and by distributor controlled load management through hot-water cylinder and interruptible irrigation control.

Orion's load management system signals to our customer's premises by injecting a carrier frequency with a digital signal into the power network that is acted upon by relays installed at the customer's connection point. There are two ripple carrier frequencies used on our system. The ripple relays are owned by the retailers, apart from approximately 2,000 that are owned by Orion, to control streetlights. Alternative signal means are also used to prepare and initiate some major customer load management methods.

We install new 11kV ripple injection plants in conjunction with new zone substations or rural zone substations that are converted from 33kV to 66kV.

Table 6.18.1 Load management systems description

System	Description	Quantity
Load management master station and RTUs	The load management master station is a SCADA system that runs independently of the network management system.	2 plus 1 spare
Upper South Island load management system (USI)	The USI load management system is a dedicated SCADA system run independently of our load management and network management systems. Two redundant servers take information from Orion, Transpower and seven other USI distributors' SCADA systems, monitor the total USI system load and send targets to the various distributors' ripple control systems to control USI total load to an overall target.	2 plus 1 historian
Ripple injection system Telenerg 175 Hz	This system operates mainly within our Region A network and is the major ripple injecting system controlling the load of approximately 160,000 customers.	27
Ripple injection system Zellweger Decabit 317Hz	The Decabit system operates predominately within our Region B network. The main reason for separate systems is the historical merger between distribution authorities and their separate ripple plant types.	17
RTU and load measurement	RTUs are used to gather information from load measurement points and consolidate totals for load management at substation levels. THE PQM and load transducers are required to accurately and reliably measure loads throughout the network.	50+ RTUs and 50+ PQMs

6.18.3 Asset Health

6.18.3.1 Condition

The condition of the load management system is described in Table 6.18.2.

Table 6.18.2 Load management systems condition

Asset	Description	Condition
Orion load management master station	The hardware and software have reached end of life, with no future support path provided by the manufacturer. Replacement is underway in the first half of this AMP period	Poor
Upper South Island load management system	This system was updated in late 2019. The system is maintained on a regular basis	Good
Ripple injection system – Region A 175Hz system	The majority of the 11kV injection plants were installed from FY04, and some components are approaching the expected useful life of 15 years. Historically, the units have been reliable and spare parts were available. The ripple controller has now reached the end of its life and no replacement is available from the manufacturer	Poor
Ripple injection system – Region B 317Hz system	The 11kV and 33kV ripple plant injection controllers are approaching their expected service life. Historically, the units have been reliable and spare parts were available. However, the ripple controller has now reached the end of its life and no replacement is available from the manufacturer	Poor
Measurements	The provision of resilient (i.e., redundant) load measurement is good at most sites but not everywhere. Light sensing for accurate timing of street lights has only a single measurement point. The measurement of loads had altered a significant amount with network changes and the redundancy of measurement is poor at some locations	Poor

6.18.3.2 Reliability

Overall our load management systems are achieving the required load shedding performance required to maintain service levels and to limit tariffs. Few failures have occurred at peak times

6.18.3.3 Issues and controls

Our maintenance and replacement programmes are developed to ensure the continuous availability of the load management system. This includes maintaining a highly resilient system and undertaking regular reviews of system capacity and performance. The level of risk for this asset class is considered to be low based on current information about the causal likelihoods and the controls with their respective effectiveness levels.

Table 6.18.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 6.18.3 Load management failure controls

Common failure cause	Known issues	Control measures
Infrastructure component failure	Server hardware/platform failure	Real time monitoring, diversity, resilient infrastructure, lifecycle management
	RTU and ripple plant failure	Spares available Emergency contract
Information system (application/database) failure	Software failure/flaw	System monitoring, diversity, resilient platforms, maintenance contracts
Cyber risks	Known escalation in cyber attacks world wide	Requesting extra support from supplier given that no software patches are available on sunset operating system
Supplier risk	Both software and hardware providers declaring product end of life with no replacements	Risk added to replacement projects

6.18 Load management systems continued

6.18.4 Maintenance plan

The complexity of the software and availability of technical support increase the difficulty and cost of maintaining the master station system.

Injection plants have a quarterly operational check as well as an annual inspection that includes measurement of installed capacitors and detailed tests on the inverter. Dusting and physical inspections are considered part of the annual maintenance. The operational expenditure in the Commerce Commission categories is shown in Table 6.18.5.

Table 6.18.4 Load management systems maintenance plan

Asset	Maintenance activity	Frequency
Master station	Supplier review	Annual
Ripple plant	Shutdown clean, inspect and test	Annual

Table 6.18.5 Load management systems operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Service interruptions and emergencies	45	45	45	45	45	45	45	45	45	45	**450**
Routine and corrective maintenance and inspections	380	390	400	400	400	400	400	400	400	400	**3,970**
Total	**425**	**435**	**445**	**445**	**445**	**445**	**445**	**445**	**445**	**445**	**4,420**

6.18.5 Replacement plan

Load management master stations
The load management master stations are critical for load shedding operations and we undertake a risk assessment annually to consider the need for upgrades. In our assessment we look at current health of system and availability of system support in coming years to continue to meet operational requirements.

The hardware and software of the USI load management master station is ageing and the operating system is no longer supported. This system is under review for refurbishment and/or migration. As part of the review we are considering ongoing resources and the cost to Orion of supporting three separate and independent SCADA systems network management, Orion load management, USI load management and whether a consolidation of SCADA systems is viable. The review is currently underway and the findings will be delivered in FY24.

Ripple plant and controllers
An age based replacement programme has been adapted to overcome asset obsolescence and availability of spares. We have had a proactive replacement programme since FY23 for ripple frequency controllers. The majority of these are now more than 15 years old and at end of life, and we have begun to see some age-related failures. Our ripple plant coupling cell equipment is replaced reactively however, we are looking to be more proactive in the future as the coupling cells are approaching their end of life also.

Table 6.18.6 Load management systems replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Zone substation	836	856	876	1416	1164	660	786	912	912	660	**9,078**
Other network assets	770	100	600	100	100	570	100	100	100	100	**2,640**
Total	**1,606**	**956**	**1,476**	**1,516**	**1,264**	**1,230**	**886**	**1,012**	**1,012**	**760**	**11,718**

6.18.5.1 Disposal

The ripple plant parts that have been retired will either be used as emergency spares or recycled where possible, depending on their condition.

Our maintenance plan has been effective in keeping our standby generators in good condition.

6.19 Generators

6.19.1 Summary

We use diesel generators as a mobile source of energy to maintain supply of electricity or provide power to customers in the short term until the network is able to be restored following a fault or during a planned interruption. To maintain a fuel supply for the generators we own diesel tanks and a mobile trailer tank.

Our maintenance plan has been effective in keeping our standby generators in good condition. We are not planning to replace any units over the next ten years. We built a shed at the Papanui Zone Substation to house our trucks and mobile generators to reduce deterioration from exposure to the elements. We have replaced a trailer mounted unit with a truck mounted in FY20 and trialed new innovative technologies.

6.19.2 Asset description

We have 14 diesel generators as shown in Table 6.19.1. We have:

- **400V truck-mounted mobile generators** – which are used to restore or maintain supply at a distribution level during a fault or planned work
- **400V building generators** – all have synchronisation gear and can pick up the entire building load. A 110kVA unit is attached to the remote TDC (Transportable Data Centre). A 550kVA unit is attached to our main office building with and another 550kVA unit is installed at Connetics' base in the Waterloo Business Park
- **400V emergency standby generators** – can be strategically placed throughout our urban network. They are used for emergency backup and can be switched on-line in a short time frame if there is a loss of supply. Two 550kVA units are at Papanui Zone Substation. The 11kVA, 30kVA and 66kVA units which have no synchronising gear are also at Papanui. The 66kVA unit is trailer mounted

Table 6.19.1 Generator types

Voltage	Type	kVA				Total	Avg age
		8 - 30	66 - 110	330 - 440	550		
400V	Mobile		2	2	1	5	11
	Building generators		1		2	3	9
	Emergency standby	2		1	3	6	13
Total						**14**	

We have six diesel tanks and a mobile trailer tank. The purpose of the tanks is to:

- provide an emergency reserve supply for the operator vehicle fleet and building generator should the Christchurch supply lines become disrupted
- fuel mobile generators for high power work
- fuel the generator at our office building on Wairakei Rd in an emergency for an extended period
- fuel mobile generators (trailer tank)

6.19 Generators continued

6.19.3 Asset health

There have been no major mechanical issues with the generators. Our generators are well maintained.

Table 6.19.2 Generator conditions by type

Voltage	Type	Condition
400V	**Mobile**	Good condition
	Building generators	Good condition
	Emergency standby	Good condition

6.19.3.1 Issues and controls

Our generators are rotating machines that are subject to vibration, heat and dust while running and in transit. As a result, our generators require regular maintenance and tuning to ensure that they stay in an optimal state. We pick up most issues during our routine maintenance.

6.19.4 Maintenance plan

We employ a number of different asset management practices for different generator groups. The different types of generators and ages require different schedules to best suit each machine. The schedules are shown in Table 6.19.3.

An annual forecast of generator operational expenditure in the Commerce Commission categories is shown in Table 6.19.4.

Table 6.19.3 Generator maintenance plan

Generator type	Scheduled maintenance
Mobile generators (400V, 110-440kVA)	Oil changed every 250 hours (note the interval is smaller for the older engines in this group of generators) Diesel and batteries tested yearly Complete functional test once a year Battery charger and block heater kept plugged in
Emergency generators (400V, 8-110 kVA 400V, 550kVA)	Battery charger and block heater kept on Oil tested yearly and changed every 3 years or every 500 hours whichever comes first Tank fuel air filters changed every 3 years Diesel and batteries tested yearly Test run monthly Run on a load bank for 30 minutes once a year at full load

Table 6.19.4 Generator operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Routine and corrective maintenance and inspections	45	45	45	45	45	45	45	45	45	45	**448**
Total	**45**	**45**	**45**	**45**	**45**	**45**	**45**	**45**	**45**	**45**	**450**

6.19.5 Replacement plan

We regularly maintain our generators and when one approaches end of life, a condition-based assessment will be conducted to see when the replacement is most economical. The 440kVA generator has done more than 8,900 hours and is 16 years old. When it gets to 10,000 hours we will assess whether it is more economic to do major maintenance or replace it with a new unit. Expenditure has been allocated for two controller and AVR replacements in each year.

6.19.5.1 Disposal

Generators are disposed of by auction when they become surplus to our requirements or they become uneconomic to continue to operate.

Our network procedures detail the disposal requirements for substances such as fuels that have the potential to spill from generators or any other form of holding or transport tank. These procedures also mandate the prompt reporting of any uncontained spillage and disposal of hazardous substances, which allows us to document the details of spillage and disposal quantities.

6.19.6 Innovation

To keep the power on for the community during emergency and network maintenance work, Orion has typically used around 150,000 litres of diesel per year in its generators, emitting the equivalent of 400 tonne of CO_2.

In FY21 we conducted a proof of concept trial to see if Orion's generators could be powered by biodiesel, a clean-burning diesel replacement made from recycled vegetable oil, produced locally.

The trial using 300 litres of GreenFuels® waste vegetable oil produced locally from fast-food outlets in one of Orion's 440kW generators was successful, generating a steady flow of acceptable power quality.

We are following up with a series of detailed live tests on a range of Orion generators, comparing biofuel with mineral diesel across a range of parameters.

Our focus is on understanding biofuel's reliability and emission reductions, and testing includes upper limit testing, comprehensive emission tests and, eventually, live tests on the network.

We are now refining our processes and conducting further trials to assess the viability of switching from diesel to biofuel on an operational scale. However, Bio-diesel supply has become difficult to get.

Most of our generators have been fitted with SCADA which provides alarming and monitoring. Reverse synchronising has been fitted to all generators 110 kVA and bigger which allows the generator to be returned from an islanded state with connected load, avoiding an outage to the customer.

Our mobile generators have been fitted with equipment to allow the generator to operate in a voltage support mode.

This is where the generator is operated in parallel with the network and as the load drops the voltage increases, allowing the generator to shut down, saving fuel.

We have now fitted control relays that allow the generator to start large loads or areas of islanded network after a fault. This has improved customer service by reducing restoration times.

We have also fitted Statcom to three trucks and have two standalone units. These allow the generators to shutdown at low load while paralleled, reducing engine wear and fuel use.

We have now fitted control relays that allow the generator to start large loads or areas of islanded network after a fault. This has improved customer service by reducing restoration times.

Table 6.19.5 Generator capital expenditure (real) - $,000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Other network assets	22	22	22	22	22	22	22	22	22	22	**220**
Total	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**220**

We have replaced most of our monitoring assets and the majority are in good condition and meet our service level targets.

6.20 Monitoring and Power Quality

6.20.1 Summary

Our monitoring assets are comprised of high voltage (11kV), GXP and power quality metering. We have replaced most of our monitoring assets and are meeting our service level targets.

6.20.2 Asset description

Our monitoring assets cover three areas in our network:

- **High voltage (11kV) customer metering** – we own the metering current transformers (CTs) and voltage transformers (VTs) along with associated test blocks and wiring at approximately 75 customer sites. Retailers connect their meters to our test block and all Orion metering transformers are certified as required by the Electricity Governance Rules
- **Transpower (GXP) metering** – we own metering at Transpower GXPs. We adopted GXP-based pricing in 1999 and most of our revenue is now derived from measurements by Transpower GXP metering. The data from these meters serves as input into our SCADA system for load management and our measurements are used to estimate readings when Transpower's meters fail
- **Power quality monitoring** – we have installed approximately 30 permanent, standards compliant, power quality measurement instruments across a cross-section, from good to poor, of distribution network sites. Data collected are statistically analysed to monitor the long-term network performance and to assist the development of standards and regulations

Table 6.20.1 Monitoring quantities by type

Asset	Quantity
Current Transformers	45
Voltage Transformers	34
Quality Meters	13
Total	**92**

6.20.3 Asset health

6.20.3.1Condition

Our monitoring assets overall have proven to be robust, are performing well and are meeting all the service level targets.

6.20.3.2 Performance

We check our metering data against Transpower's data. If there is a significant difference, meter tests may be required to understand where the discrepancy has occurred.

Our power quality management has historically been largely reactive as we have built our methodologies around customer complaints. However, we now also focus on projects that are proactive in nature which when completed will reduce the number of complaints we receive and improve our network performance.

We will continue to monitor the quality of the network to assess the impact of the increasing number of non-linear loads that are connected each year.

6.20.3.3 Issues and controls

Metering transformers are extremely reliable standard components of high voltage switchgear and are maintained and replaced as part of our standard switchgear maintenance and replacement procedures. We hold sufficient spares to cover failures of CTs, VTs and other metering equipment.

6.20.4 Maintenance plan

We regularly inspect the metering sites, carry out appropriate calibration checks and witness the calibration checks on Transpower's metering. Our meter test service providers are required to have registered test house facilities which comply with the Electricity Governance rules. They are required to have documented evidence of up-to-date testing methods and have competent staff to perform the work.

The maintenance plan is shown in Table 6.20.2 and the associated expenditure in the Commerce Commission's categories is shown in Table 6.20.3. The capital expenditure will be used to conduct testing of HV meters every 10 years for certification as well as maintaining our statcoms on an annual basis.

Table 6.20.2 Monitoring maintenance plan

Maintenance activity	Strategy	Frequency
CTs & VTs	The Electricity Marketing rules require that our CTs and VTs must be recalibrated	10 years
Power quality meters	Repaired / replaced when they fail	As required

Table 6.20.3 Monitoring operational expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Routine and corrective maintenance and inspections	120	21	29	5	13	29	21	29	99	21	**387**
Total	**120**	**21**	**29**	**5**	**13**	**29**	**21**	**29**	**99**	**21**	**387**

6.20.5 Replacement plan

These are non-critical assets so a reactive approach is used for identifying required replacement work. We hold spares and a small amount of budget is set aside for unscheduled replacements. Table 6.20.4 shows the replacement capex in the Commerce Commission's categories. The expenditure is based on replacing end of life meters and metering equipment over the next 10 years.

Table 6.20.4 Monitoring replacement capital expenditure (real) – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Other network assets	98	98	98	98	24	24	24	24	24	24	**536**
Total	**98**	**98**	**98**	**98**	**24**	**24**	**24**	**24**	**24**	**24**	**536**

7

Developing our network

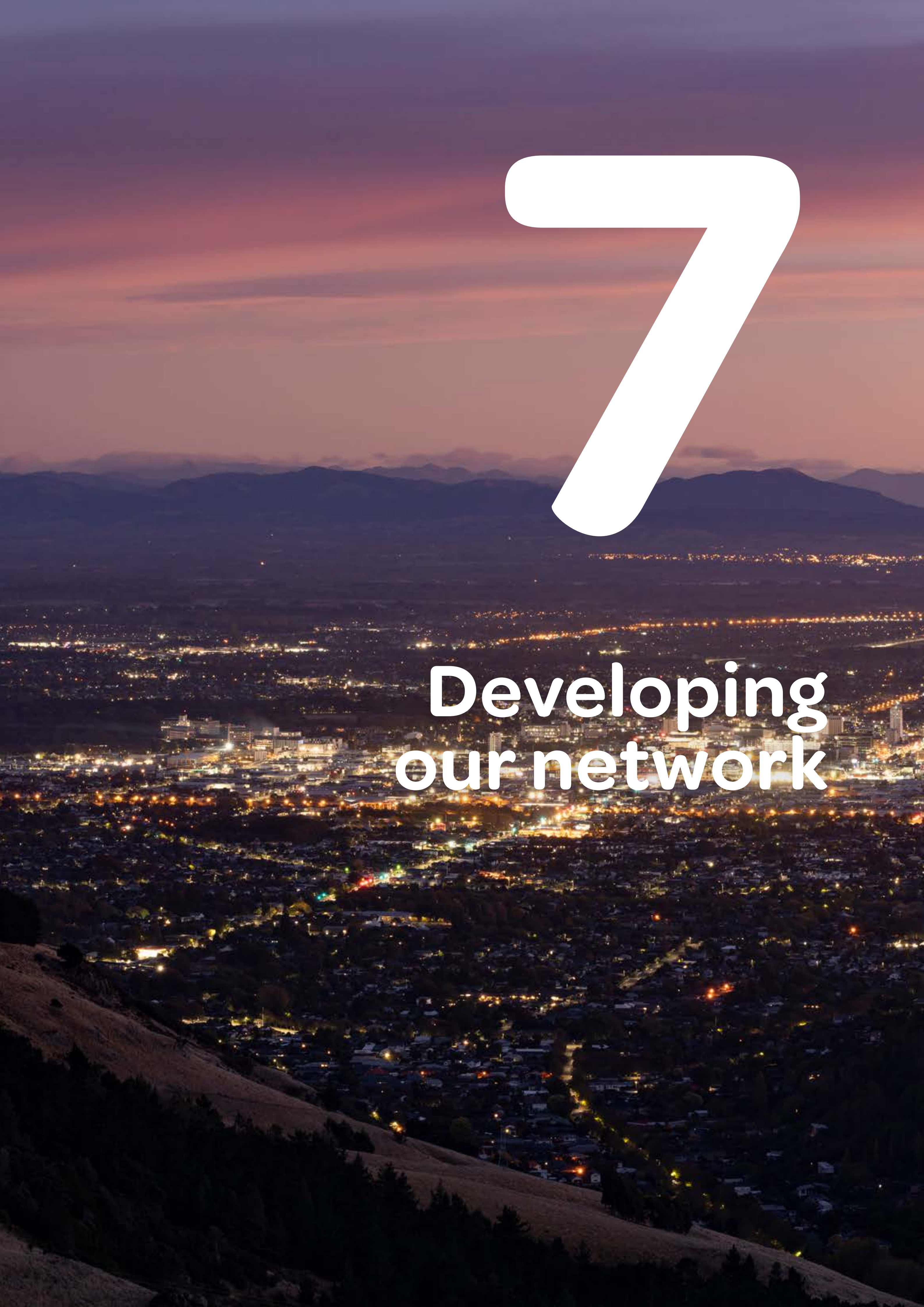


Photo: View of Christchurch and wider region taken from the Port Hills.

Contents

7.1 Introduction

In this section we set out how we are developing our network to prepare for the future. We discuss the changing demands on our infrastructure as we respond to the growing needs of our region and opportunities posed by the transition to low carbon energy.

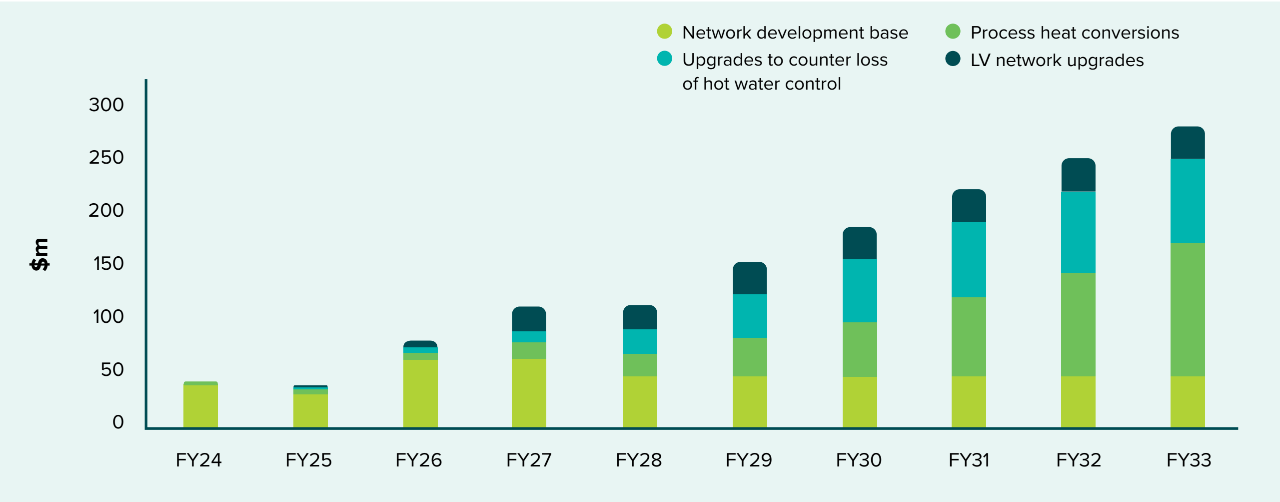
The demand for electricity is expected to increase dramatically over coming decades as the pace of decarbonisation accelerates, and the factors driving this change are set out in Sections 2 and 5. Along with increased demand, we also expect developments in the technology needed to balance electricity across our network to require increased investment in new assets. Orion's capital expenditure needs to keep pace with the growing demand for our network, and the increasingly sophisticated transactions across it.

This section describes the major investments we plan to make in our high voltage (HV) network in the next 10 years and our LV investment approach. These planned investments are categorised by the network areas they impact, to enable customers to readily identify projects that will most affect them.

For the planned network capital expenditure across our whole network over this 10 year AMP period, see Figure 7.1.1.

Orion's capital expenditure needs to keep pace with the growing demand for our network, and the increasingly sophisticated transactions across it.

Figure 7.1.1



The development of our network to meet future needs has significant implications for expenditure. We will make every effort to keep our costs as low as possible, including introducing a range of efficiencies, many derived from our focus on data and digitisation of our operations. We will also explore how we can unlock value from customer owned devices.

Where feasible, we will delay or decide not to proceed with projects by using non-traditional flexibility solutions our customers may be able to provide. Where flexibility solutions offer a lower cost option than network build, our operating expenditures will increase above that included in this AMP. However, greater savings in capital expenditure will be made – providing a net benefit for our customers.

In 7.2, we set out the current security gaps on our network and how we are addressing them, before demonstrating the effects of decarbonisation and technology change on load forecasts at GXP and zone substation level. We then describe the key investments we plan to address that growth.

7.2 Current network security gaps

The GXP gaps identified in Table 7.2.1 are based on the application of our Security of Supply Standard to Transpower's core-grid, spur or GXP assets. For a copy of the Standard, see Section 5.

Table 7.2.1 and Table 7.2.2 only show current Security of Supply Standard gaps. Additional projects listed in the 10 year AMP provide solutions for future forecast gaps that are not stated here. Some projects address more than one security gap and are therefore quoted in more than one location.

Table 7.2.1 Transpower GXP security gaps

GXP	Network gap	Solution	Proposed date
Islington	Partial loss of restoration for an Islington 220/33kV dual transformer failure	Upgrading Shands Rd ZS from 33kV to 66kV introduces greater 11kV tie capability to remaining zone substations supplied by Islington 33kV	FY31-32
Hororata	Interruption to all Hororata GXP load for a 66kV bus fault (restorable) Only partial restoration achievable for a Hororata 66/33kV dual transformer failure	Long-term solution of feeding load from proposed Norwood GXP. This requires all the remaining 33kV zone substations fed from Hororata GXP to be converted to 66kV. We have a set of projects that establishes a 66kV tie from Norwood GXP to Hororata GXP via Greendale ZS (Projects 1086, 1087 and 1072). This programme will enable fast restoration for a loss of the Hororata 66kV GXP	Beyond the current AMP 10 year period

Table 7.2.2 Subtransmission network security gaps

Substation	Network gap	Solution	Proposed date
Dallington	Loss of 28MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes	Complete a 66kV loop back to Bromley. Project 491	FY28
Rawhiti	Loss of 30MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes		
Hororata	Interruption to all Hororata 33kV GXP load for a 33kV bus fault (restorable)	Installation of a bus coupler as part of 33kV switchgear renewal. Project 1064	FY27
Waimakariri	Loss of 20MW of load for a single 66kV circuit. Restoration achievable in 5 minutes	Complete a 66kV loop from Papanui via Belfast and Waimakariri. Project 942	TBA
Lancaster	Loss of 21MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes	Overall objective: complete a 66kV loop from Hoon Hay to Milton Bromley to Milton ZS 66kV cable (Project 962) Lancaster ZS to Milton ZS 66kV (Project 589) Milton ZS 66kV switchgear and building (Project 723)	FY29
Hororata to Springston 66kV circuit	The load on the 66kV overhead circuit between Springston and Hororata is in excess of 15MVA but still experiences an interruption for a single overhead line fault	Complete a 66kV closed loop between Norwood – Dunsandel – Killinchy – Brookside ZS's. Projects 940, 941 and 946	FY25

7.3 Load forecasts

Community and industry moves to decarbonise and strong population growth in our region are creating increasing demand for electricity across our network.

Different parts of our network will be affected more than others. Industrial process heat conversions are generally going to occur in older industrial areas, and while prices remain high, electric vehicle uptake is likely to be in wealthier areas initially.

When we plan our network investments, this means we need to forecast loading at individual area levels, as well as in total across Orion's network.

In the future, as our scenario modelling matures and we integrate low voltage data, our load forecasting will be down to individual feeder, or street level. In future AMPs, we will show much more detailed loading forecasts, including more nuanced upper and lower ranges. Currently, we are only able to show forecasts down to GXP and zone substation level, section.

To determine where future network security gaps will occur, each substation is assigned a Security Standard Class which outlines our restoration targets under different contingency scenarios. See Section 5.2.3 for further details.

Firm capacity is determined by calculating the remaining capacity of each site should one item of plant fail (N-1).

The 10 year range columns in Tables 7.3.1, 7.3.2 and 7.3.3 show the potential load based on the high and low forecast system demand scenarios described in Section 5.6.2.2. These are our current best estimates, and may change as our forecasting improves over time.

7.3.1 Transpower GXP load forecasts

Table 7.3.1 indicates the capacity of each Transpower GXP that supplies our network. Present and expected maximum demands over the next 5 years are also shown, along with year 10 scenarios.

The impact of projects in this plan is not reflected in the load forecasts. The tabled loads are those expected if no development work is undertaken to show the need for the projects. Firm capacity is the capacity of each site should one item of plant fail. See Section 5.2 for a map of Transpower's system in the Orion network area.

Our proposed resolution for Orion Islington 66kV is to mitigate through transfer of seven zone substations to Norwood GXP and monitor the situation.

Table 7.3.1 GXP substations – load forecasts (MVA)

GXP substation	Security Standard Class	Firm capacity	Actual FY22	FY23	FY24	FY25	FY26	FY27	FY28	10 year range (excluding expected additional growth)	Expected additional growth with unknown timing
Bromley 66kV	A1	220	151	153	156	158	159	160	162	167 - 197	5
Islington 33kV	B1	107	73	76	80	81	82	84	84	92 - 103	10
Orion Islington 66kV	A1	480 [1]	438	425	441	447	456	461	467	492 - 533	21
Hororata 33kV [2]	C1	23	19	21	21	21	22	22	22	22 - 24	0
Kimberley 66kV, Hororata (66 & 33kV)	C1	70 [3]	46	49	49	50	50	50	51	51 - 52	3
Arthur's Pass	D1	3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4 - 0.5	0
Castle Hill	D1	3.75	0.7	0.8	1.0	1.0	1.0	1.0	1.0	1.0 - 1.1	0
Coleridge	D1	2.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4 - 0.5	0

Notes:

Expected additional growth with unknown timing is due to industrial decarbonisation projects.

1. 532 MVA total firm capacity. Assumes only 45% MainPower's of load is fed from Islington post Islington T6 contingency. Emerging constraint to be managed by transferring Larcomb and Weedons to Norwood GXP.
2. Monitor growth and transfer load to Hororata 66kV if needed in the short-term.
3. Assumes full generating capacity available from Coleridge. Can be limited to 40MW capacity when Coleridge is not generating or providing reactive support.

Indicates load greater than firm capacity

7.3.1.1 Zone substation load forecasts

Tables 7.3.2 and 7.3.3 compare the firm capacity of each of our zone substations with present and forecast load.

Our proposed plans to meet forecast load in Region A zone substations, are:

Halswell – increase zone substation transformer capacity

Papanui – transfer to Belfast zone substation

Shands Road – upgrade capacity with site conversion to 66kV

For our other zone substations where forecast load is greater than firm capacity, we will monitor the situation and determine a solution closer the time it is needed.

See Section 7.4 for details of our planned investments for these sites.

Table 7.3.2 Region A zone substations – load forecasts (MVA)

Zone substation	Security Standard Class	Firm capacity	Actual winter FY22	FY23	FY24	FY25	FY26	FY27	FY28	10 year range (excluding next column, ie that may be an addition)	Expected additional growth with unknown timing
Addington 11kV #1	B2	30	18	18	20	21	21	21	21	21 - 25	
Addington 11kV #2	B2	30	22	22	22	22	22	22	22	23 - 26	
Armagh	A2	40	17	18	18	19	22	23	24	27 - 32	
Barnett Park	B3	15*	10	10	10	10	10	10	10	10 - 13	
Belfast	B3	15*	0	8	9	10	10	11	11	14 - 14	
Bromley	B2	60	34	33	34	34	34	34	34	35 - 53	
Dallington	B2	40	28	27	27	27	27	28	28	28 - 42	
Fendalton	B2	40	36	35	35	35	35	35	35	35 - 46	2
Halswell	B2	23	19	20	21	22	24	25	26	31 - 44	
Hawthornden	B2	40	35	34	34	34	35	35	35	36 - 44	3
Heathcote	B2	40	25	24	25	25	25	25	25	26 - 35	3
Hoon Hay	B2	40	32	31	31	31	31	32	32	32 - 51	
Hornby	B2	20	15	15	16	16	16	16	16	16 - 18	
Ilam	B3	11	8	8	8	8	8	8	8	8 - 12	
Lancaster	A2	40	21	21	21	21	22	22	22	23 - 30	1
McFaddens	B2	40	36	35	35	35	35	35	36	36 - 47	1
Middleton	B2	40	27	26	26	27	28	28	28	28 - 31	11
Milton	B2	40	39	38	38	38	39	39	39	40 - 52	
Moffett	B3	23	15	14	15	15	15	15	16	18 - 20	
Oxford Tuam	A2	40	17	17	17	17	18	18	18	19 - 20	1
Papanui	B2	48	46	38	41	41	41	41	41	41 - 44	
Prebbleton*	B3	15	8	8	8	9	9	9	9	10 - 13	
Rawhiti	B2	40	30	29	29	29	29	29	29	29 - 44	
Shands	B3	20	13	15	17	17	18	18	19	22 - 24	7
Sockburn	B2	39	26	25	26	26	26	26	26	26 - 30	3
Waimakariri	B2	40	20	20	21	21	21	22	22	23 - 25	

* Single transformer – security standard limits load to 15MW, 11kV ties from neighbouring sites provide backup capacity for all load

Indicates load greater than firm capacity

7.3 Load forecasts continued

Our proposed plans to meet forecast load in Region B zone substations, are:

Highfield – re-rate transformer then transfer to new substation at Norwood. Load shift to Rolleston if needed

Lincoln – load shift from Lincoln to Springston

Rolleston – new Burnham 23MVA substation to replace Rolleston

Springston 66/11kV – existing transformer to be replaced, see Project 1099

For Weedons ZS, we will monitor the situation and determine a solution closer the time it is needed.

See Section 7.4 for details of our planned investments for these sites.

Table 7.3.3 Region B zone substations – load forecasts (MVA)

Zone substation	Security Standard Class	Firm capacity	Actual winter FY22	FY23	FY24	FY25	FY26	FY27	FY28	10 year range (excluding next column, ie that may be an addition)		Expected additional growth with unknown timing
Annat*	C4	7.5	3.6	4	4	4	4	4	4	4	4	
Bankside*	C3	10	3.8	4	4	4	4	4	4	4	4	
Brookside 66kV*	C3	10	7.8	8	8	8	8	8	8	8	9	
Darfield*	B3	8.8	5.2	6	6	6	6	6	6	6	7	
Diamond Harbour*	B3	7.5	2.7	3	3	3	3	3	3	3	4	
Dunsandel	A2	23	16.1	23	23	23	23	23	23	22	23	3
Duvauchelle	B3	7.5	4.4	4	4	4	4	4	4	4	5	
Greendale*	C3	10	6.2	7	7	7	7	7	7	7	7	
Highfield*	C3	10	7.9	10	10	10	10	10	10	6	6	
Hills Rd*	B3	10	6.5	8	8	8	8	8	8	8	9	
Hororata*	C3	10	7.7	8	8	8	8	8	8	8	9	
Killinchy*	C3	10	8.6	9	9	9	9	9	9	9	9	
Kimberley	A3	23	14.1	15	15	15	15	15	14	14	14	3
Larcomb	B3	23	18.8	18	18	18	18	18	18	18	19	1
Lincoln	B3	10	10.0	10	10	11	11	11	12	12	16	
Little River*	C4	2.5	0.7	1	1	1	1	1	1	1	1	
Motukarara	C4	7.5	3.1	3	3	3	3	3	3	3	4	
Rolleston	B3	10	10.9	11	13	13	14	14	14	16	20	
Springston 66/33kV	B2	60	34.8	36	38	40	42	43	44	43	47	
Springston 66/11kV*	B3	13	7.7	8	11	11	11	12	13	17	27	
Te Pirita	C3	10	8.6	9	9	9	9	9	9	9	9	
Weedons	B3	23	14.0	16	20	20	20	21	21	22	25	
Lincoln + Springston		20	17.7	17	18	18	18	18	19	30	24	

* Denotes single transformer or line

Indicates load greater than firm capacity

7.3.2 LV network constraint forecasts

Based on LV modelling undertaken to date, we believe most of our low voltage network has sufficient capacity to meet demand in the short-to-medium term. However, as EVs are adopted by more households and businesses, and we gather more data on our low voltage network utilisation, it is expected that reinforcement above historic levels will be required. We are currently reviewing our LV strategy and have increased our reinforcement budget forecast to address these constraints. The projected constraints on our LV network are predominantly located in urban areas.

Figure 5.6.8, Section 5.6.2.3 illustrates their geographic distribution across our region by Stats NZ areas (SA2). Refer to Section 7.4.2.2 for details of our proactive LV reinforcement programme.

Orion will undertake LV network reinforcement through a portfolio of measures such as addressing phase imbalance, upgrading and adding new distribution transformers, and installing new low voltage lines and cables. Where cost effective, we will also investigate and implement non-traditional solutions to defer reinforcement such as static compensators (STATCOMs) to provide voltage support, or network scale batteries to reduce distribution transformer and 11kV feeder demand at peak times. In some cases, we may undertake greater Distributed Energy Resources Management, for example EV smart charging, to reduce peak load.

These solutions will deliver on our asset management strategy focus on embracing opportunities to re-imagine our future network.

7.4. Investment plans

This section lists our project proposals to address capacity and security constraints on our network. Our network development projects are driven by a variety of factors such as customer need, load growth, environmental considerations and increasing overall network resilience. Where economic, projects have been designed to meet our Security of Supply Standard requirements. See Section 5.2.3.1.

We account for the time it takes to plan and undertake the proposed projects for network improvements. This includes:

- the time required to procure zone substation land and/or negotiate circuit routes – typically one or two years
- the time required for detailed design – typically one year
- management of service provider resources by providing a consistent work-flow

A major 66kV or 33kV network development project takes approximately three years to plan, design and build, while smaller 11kV projects take around 18 months. A 400V solution can take several months. In this context, it is prudent to be flexible in how we implement our network development proposals, rather than rigidly adhere to a project schedule based on an outdated forecast.

7.4.1 HV programmes of work and other projects

The following section outlines our Network Development HV projects and programmes of work planned for the next 10 years. Projects in the first two years of the plan are considered firm. Projects scheduled in the first five years of the plan have programme overviews and brief descriptions for each. In contrast, projects in the latter five years are only outlined by project name, an indicative construction year, and their strategic driver(s).

There are ten main programmes of work scheduled in the 10 year period:

- Region A 66kV subtransmission resilience, Section 7.4.1.1
- Southwest Christchurch and surrounding areas' growth and resilience, Section 7.4.1.2
- Northern Christchurch network capacity, Section 7.4.1.3
- Region A subtransmission capacity, Section 7.4.1.4
- Region B 66kV subtransmission capacity, Section 7.4.1.5
- Customer driven projects, Section 7.4.1.6
- Lincoln area capacity and resilience improvement, Section 7.4.1.7
- Rolleston area capacity and resilience, Section 7.4.1.8
- Hororata GXP capacity and resilience, Section 7.4.1.9
- Other projects, Section 7.4.1.10

The following Region A and Region B maps indicate the location and timing of individual forecast major HV projects in this 10 year period, and the details of each project follow.

We have specified the asset management objectives for each programme of work, and their link to our Group Strategy, see Section 2.13.

The key for the asset management objectives is:

Primary objective:

Primary

Secondary objective:

Secondary

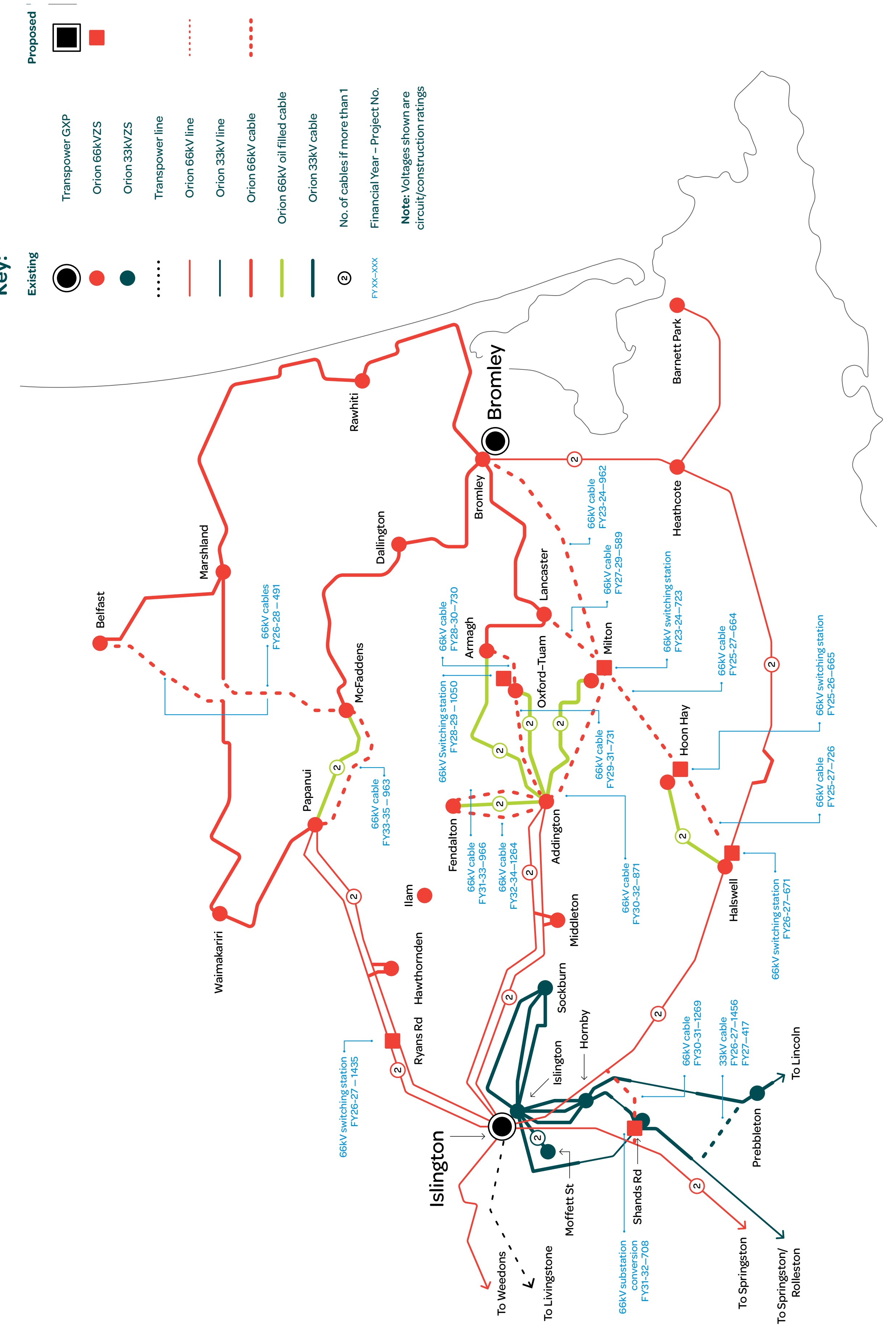
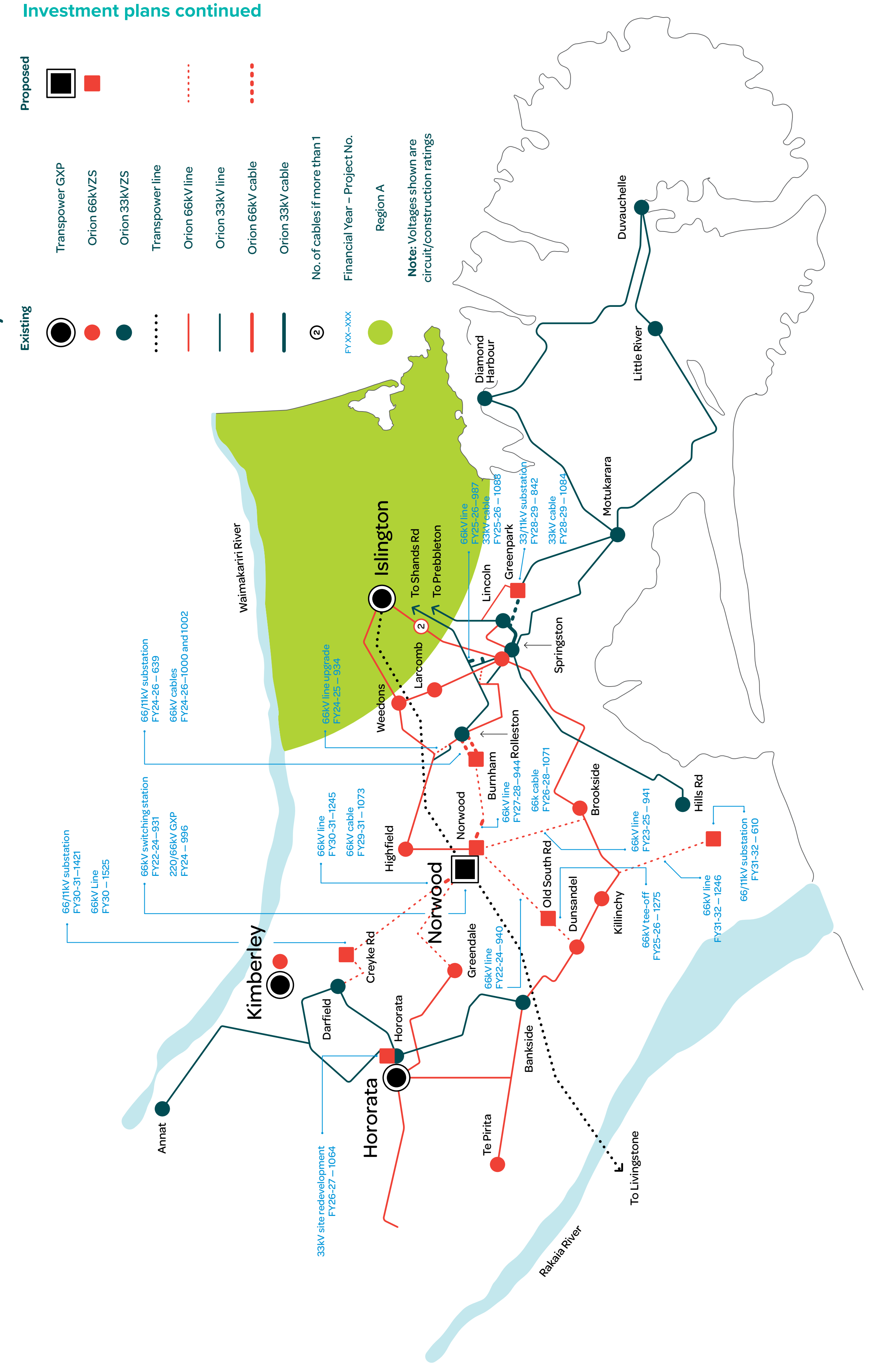


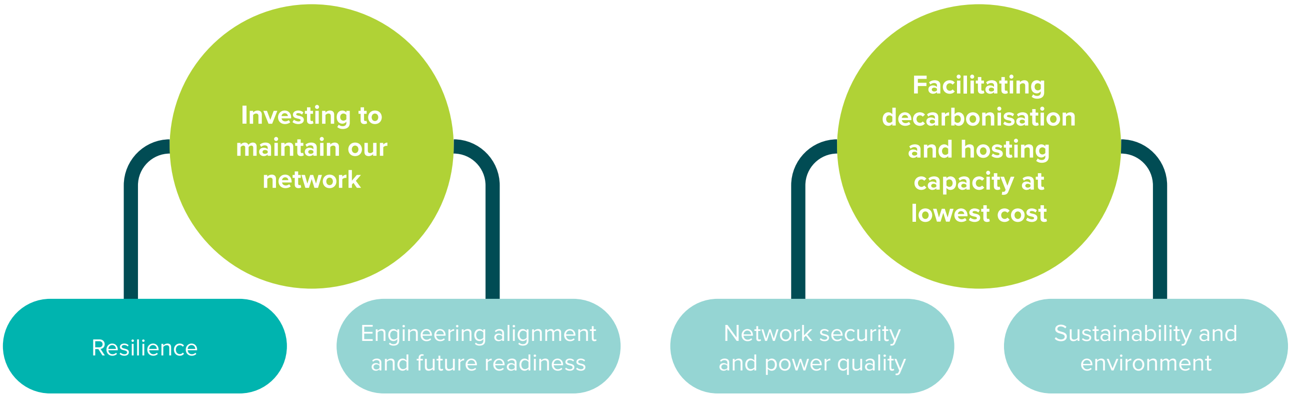
Figure 7.4.1 Region A subtransmission 66kV and 33kV – existing and proposed

Figure 7.4.2 Region B subtransmission 66kV and 33kV – existing and proposed



7.4.1.1 Region A 66kV subtransmission resilience

Investment drivers



To increase our urban 66kV subtransmission network's resilience against the impact of a major seismic event, we have developed a programme to replace our remaining 40km of 66kV oil filled underground cables that commenced in FY23. Although resilience and obsolescence are the dominant drivers, this replacement programme also incorporates forecast network growth and other asset lifecycle replacement projects across our Region A 66kV network.

We considered non-network solutions, however due to the capacity required at a subtransmission level these solutions are not suitable to supply base level demand. Non-network solutions are unable to provide subtransmission N-1 security, because repair times on 66kV equipment can be two weeks for joint issues. This is far beyond the energy storage capability of existing known Distributed Energy Resource (DER) systems during our winter peak load times.

This programme also replaces the legacy Region A 66kV bulk-supply point spoke-and-hub architecture with a far more resilient interconnected GXP ring architecture. The projects in this programme that fall within the 10 year plan are outlined in Table 7.4.1.

Table 7.4.1 Region A 66kV subtransmission resilience – HV major projects

No.	Project title		Year	Business case existing (yes/no)
723	**Milton ZS 66kV switchgear and building**		**FY23-24**	**Yes**
	Issue	The Milton ZS to Lancaster ZS 66kV cable (Project 589) will require switchgear installation at Milton ZS.		
	Chosen solution	This project is for the construction of a new 66kV switchroom, and purchase, installation and commissioning of 66kV switchgear at Milton ZS.		
	Remarks/alternatives	This switching station is located on a pivotal intersection of the proposed 66kV network. This facilitates shifting zone substations between GXPs to manage their growth constraints and provides resilience for GXP issues.		
962	**Bromley ZS to Milton ZS 66kV cable**		**FY23-24**	**Yes**
	Issue	As part of the 66kV oil filled cable renewal programme a high-level HILP analysis identified there was a need for an additional circuit out of Bromley GXP to cover for Islington 66kV GXP contingencies.		
	Chosen solution	This project is to purchase, install and commission a new 66kV cable between Bromley ZS and the new Milton ZS 66kV switchroom, Project 723.		
	Remarks/alternatives	The Bromley ZS 66kV bay for this project is the ex-Lancaster ZS feeder bay 170.		

Table 7.4.1 Region A 66kV subtransmission resilience – HV major projects (continued)

No.	Project title		Year	Business case existing (yes/no)
665	**Hoon Hay ZS 66kV switchgear and building**		**FY25-26**	**No**
	Issue	Hoon Hay ZS is currently supplied via dual circuit transformer cable feeders from Halswell ZS. These cables are 66kV oil filled cables so are programmed for renewal with a new diverse route 66kV closed-ring supply from Bromley ZS. To facilitate this new architecture a 66kV switchroom is required at Hoon Hay ZS.		
	Chosen solution	This project is to construct, equip and commission a new 66kV switchroom at Hoon Hay ZS to enable connection of the new 66kV cable circuits from Halswell ZS (Project 726) and Milton ZS (Project 664).		
	Remarks/alternatives	The new building will fit within the existing Hoon Hay ZS site, but further land acquisition is needed to meet building set-back requirements.		
872	**Addington ZS 66kV bus coupler**		**FY25-26**	**No**
	Issue	Addington ZS 66kV currently operates as two separate 66kV supply points due to the lack of busbar protection or bus coupler.		
	Chosen solution	This project is the purchase, construction and commissioning of the 66kV switchgear to create a bus coupler and fit bus zone protection to the 66kV bus.		
	Remarks/alternatives	This project will enable the 66kV bus at Addington to be operated closed upon completion of the new CBD 66kV ring.		
664	**Milton ZS to Hoon Hay ZS 66kV cable**		**FY25-27**	**No**
	Issue	To facilitate the new Region A 66kV architecture as part of the 66kV oil filled cable renewal programme a cable connection between Milton ZS and Hoon Hay ZS is required.		
	Chosen solution	This project is the purchase, installation and commissioning of a new 66kV cable between the new Milton ZS 66kV switchroom (Project 723) and the new Hoon Hay ZS 66kV switchroom (Project 665).		
	Remarks/alternatives	This project addresses the existing lack of route diversity supplying Hoon Hay and mitigates the emerging constraint on the Islington – Halswell tower line.		
726	**Halswell ZS to Hoon Hay ZS 66kV cable**		**FY25-27**	**No**
	Issue	Hoon Hay ZS is currently supplied via spur dual circuit 66kV oil filled cables from Halswell ZS. These cables are a seismic vulnerability and are to be replaced with a new closed-ring 66kV architecture.		
	Chosen solution	This project is the purchase, installation and commissioning of a new 66kV cable between the new Halswell ZS 66kV switchroom (Project 671) and the new Hoon Hay ZS 66kV switchroom (Project 665).		
	Remarks/alternatives	This project will supply Hoon Hay ZS with a 66kV supply with diverse supply routes, providing full N-1 security of supply.		
671	**Halswell ZS 66kV switchgear and building**		**FY26-27**	**No**
	Issue	Halswell ZS is a pivotal supply point for managing GXP loads on the current and future 66kV subtransmission network, but the limitations of the existing 66kV arrangement does not allow loads to be split between Islington and Bromley GXPs.		
	Chosen solution	This project is the construction and commissioning of a new 66kV ring-bus and switchroom at Halswell ZS.		
	Remarks/alternatives	This project has been timed to coincide with the lifecycle renewal of four 66kV CBs at Halswell ZS and the purchase, installation and commissioning of a 3rd 11kV bus section and new 23MVA transformer (Project 919) to increase the 11kV capacity of Halswell ZS.		

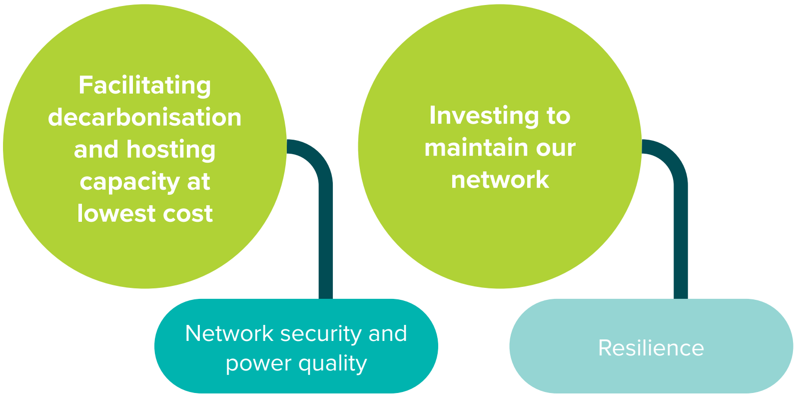
7.4 Investment plans continued

Table 7.4.1 Region A 66kV subtransmission resilience – HV major projects (continued)

No.	Project title		Year	Business case existing (yes/no)
1050	**Oxford Tuam ZS 66kV switchgear and building**		**FY28-29**	**No**
	Issue	The proposed replacement Region A 66kV architecture has Oxford Tuam ZS on a closed-ring supply requiring a new 66kV switching station.		
	Chosen solution	This project is the construction, installation and commissioning of a new 66kV indoor switching station on our section adjacent to the existing Oxford Tuam ZS site.		
	Remarks/alternatives	Projects 730 and 731 are the 66kV cable projects that connect this into the network.		
589	**Lancaster ZS to Milton ZS 66kV cable**		**FY27-29**	**Yes**
	Issue	The post-earthquake architecture review highlighted that the high value Central City load requires additional subtransmission support. In particular, improved cover for the loss of Addington zone substation is needed.		
	Chosen solution	A new 66kV cable between Lancaster and Milton zone substations will provide extra security of supply for the CBD.		
	Remarks/alternatives	This cable link was envisaged as part of our post-earthquake 2012 subtransmission architecture review.		
1445	**Milton ZS transformer alteration**		**FY28-29**	**Yes**
	Issue	The Milton ZS transformers are direct fed from Addington ZS via dual 66kV oil filled cables. These cables are due for retirement and are seismically vulnerable.		
	Chosen solution	Upon the completion of the Lancaster ZS to Milton ZS 66kV cable the Milton transformers are to be transferred over to the new Milton 66kV switching station (Project 723).		
730	**Armagh ZS to Oxford Tuam ZS 66kV cable**		**FY28-30**	**No**
	Issue	With the construction of the new Oxford Tuam ZS 66kV switching station (Project 1050) new 66kV cables are required to replace the oil filled ones.		
	Chosen solution	The current dual feeder oil filled cable supply comes from Addington ZS so this is the first replacement cable. This cable will also provide an alternate supply path from Armagh ZS and will form part of the new CBD ring.		
731	**Addington ZS to Oxford-Tuam ZS 66kV cable**		**FY29-31**	**No**
	Issue	Oxford-Tuam ZS is currently supplied via spur dual circuit 66kV oil filled cables from Addington ZS. These cables are a seismic vulnerability and are to be replaced.		
	Chosen solution	This project is to purchase, install and commission a new 66kV cable between Addington ZS and Oxford-Tuam ZS.		
871	**Addington ZS to Milton ZS 66kV cable**		**FY30-32**	**No**
966	**Addington ZS to Fendalton ZS T1 66kV cable**		**FY31-33**	**No**
1264	**Addington ZS to Fendalton ZS T2 66kV cable**		**FY32-34**	**No**
963	**Papanui ZS to McFaddens ZS 66kV cable**		**FY33-35**	**No**

7.4.1.2 Southwest Christchurch and surrounding areas' growth and resilience

Investment drivers



The southwest area of Christchurch and fringe townships are experiencing steady load growth due to the green-fields expansion of residential subdivisions in and around Halswell and Prebbleton and the popularity of the Hornby industrial belt, on the fringe of Christchurch city.

The forecast load on the Halswell and Shands Rd substations will exceed their capacities so this body of projects will restore network security and provide headroom for the forecast increase in electric vehicle charging during peak load times. The significant subdivision expansion at Prebbleton and increased arterial route traffic is driving the need for major roading upgrades. SDC driven safety improvements on major arterial routes requires parts of our 33kV network to be undergrounded. To ensure efficiency, we have catered for planned future works while roading construction is occurring.

A secondary driver is to address the resilience of the Islington GXP 33kV supply point. Shands Rd ZS will be converted to 66kV, removing load from the 33kV system, strengthening the ability to fully restore load after a major double transformer fault 33kV outage.

The timing of the Halswell ZS upgrade will coordinate with the Region A 66kV subtransmission resilience programme, see Section 7.4.1.1, ensuring that the subtransmission architecture will support the additional load.

Table 7.4.2 Southwest Christchurch and surrounding areas' growth and resilience – HV major projects

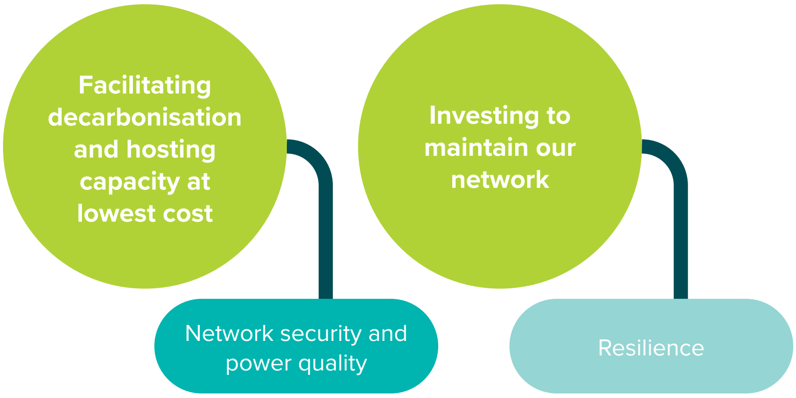
No.	Project title		Year	Business case existing (yes/no)
1450	**Shands and Hamptons Rd roundabout 33kV**		**FY24**	**Yes**
	Issue	Selwyn District Council are constructing a roundabout on the corner of Shands Rd and Hamptons Rd. Prebbleton zone substation currently only has a single 33kV circuit supplying it meaning that 11kV switching would be required to restore supply in a contingency event.		
	Chosen solution	Tee in to the existing 33kV overhead on Shands Rd with a new 33kV cable and lay partially down Hamptons Rd, towards Prebbleton ZS, in coordination with the new roundabout construction.		
	Remarks/alternatives	This work is in preparation for a future connection into Prebbleton ZS. See Projects 1456, 416 and 417		
1456	**Hamptons Rd road widening reticulation**		**FY26-27**	**No**
	Issue	Prebbleton zone substation currently only has a single 33kV circuit supplying it meaning that 11kV switching would be required to restore supply in a contingency event. Selwyn District Council are doing road widening works along Hamptons Rd for a new subdivision (plan change 68).		
	Chosen solution	Extend the 33kV cable installed in project 1450 along Hamptons Rd in coordination with the road widening works.		

Table 7.4.2 Southwest Christchurch and surrounding areas' growth and resilience – HV major projects (continued)				
No.	**Project title**		**Year**	**Business case existing (yes/no)**
919	**Halswell ZS 3rd transformer and 11kV switchgear**		**FY26-27**	**No**
	Issue	High residential growth in the southwest of Christchurch has meant that the substation is forecast to exceed the N-1 limit.		
	Chosen solution	Purchase, install and commission 3rd transformer and new 11kV switchgear for 3rd bus section. This project includes the 11kV switchroom and 23MVA transformer pad construction.		
	Remarks/alternatives	An alternative to introduce new capacity is to establish a new zone substation (Awatea), but upgrading an existing established site is much more cost effective. Upgrading Halswell to a 2x 40MVA transformer site was considered but ruled out due to the need to upgrade the existing 11kV switchgear.		
417	**Shands 33kV tee to Prebbleton ZS 33kV cable**		**FY27**	**No**
	Issue	Projects 1450 and 1456 do not fully complete the 33kV network extension to establish the new subtransmission feeder to Prebbleton ZS.		
	Chosen solution	This project extends the 33kV cables laid in Project 1450 and 1456 into Prebbleton ZS.		
416	**Prebbleton ZS second transformer**		**FY27-28**	**No**
	Issue	Depending on diversity of loads between Hornby, Shands and Prebbleton zone substations, and when the load at Prebbleton zone substation reaches 15MVA, the capacity of the 33kV subtransmission network will need to be increased.		
	Chosen solution	This installs a 2nd transformer and additional 33kV switchgear to terminate the second circuit from Islington (Shands) / Springston.		
	Remarks/alternatives	This project, in-conjunction with Projects 417 and 1450 will provide Prebbleton ZS with full N-1 for both transformer and subtransmission single faults.		
669	**Shands Rd ZS site redevelopment**		**FY27-28**	**No**
	Issue	The 33kV and 11kV switchgear is due for replacement at Shands Rd ZS. The existing 33kV outdoor structure has inadequate space for the installation of our standard equipment. Also, the 11kV switchgear housed in pre-cast modular buildings is due for replacement and space constrained with no ability to expand the switchboard size.		
	Chosen solution	As part of the surrounding industrial subdivision we have secured an adjacent lot to Shands Rd ZS. This project is to construct new switch-rooms to coincide with the lifecycle replacement of the 33 and 11kV switchgear. The 33kV switchroom will be constructed at 66kV insulation levels to prepare the site for conversion from 33kV to 66kV (Project 708).		
	Remarks/alternatives	Equipping the existing modular buildings with new switchgear is not ideal due to the quantity of modifications required and physical constraints.		
702	**Shands Rd ZS 66kV termination poles**		**FY31-32**	**No**
708	**Shands Rd ZS 33kV to 66kV conversion**		**FY31-32**	**No**
1269	**Shands Rd ZS to Islington / Halswell ZS tower line 66kV cables**		**FY30-32**	**No**

Table 7.4.3 Southwest Christchurch and surrounding areas' growth and resilience – HV minor projects				
No.	**Project title**		**Year**	**Business case existing (yes/no)**
1524	**Halswell area 11kV reinforcement**		**FY27**	**No**
	Issue	The firm capacity of Halswell ZS is increasing to 46MVA (Project 919), but there is insufficient 11kV feeder capacity to utilise the capacity.		
	Chosen solution	This project creates two new feeders direct from the expanded 11kV switchboard at Halswell ZS.		

7.4.1.3 Northern Christchurch network capacity

Investment drivers



Presently Orion's Belfast, Dallington, Rawhiti and Waimakariri zone substations are fed on either single spur cable or open-ring 66kV supplies and have current and potential loads in-excess of 15MVA. These sites do not currently meet our Security of Supply criteria as they are vulnerable to complete outages for single cable faults. Belfast zone substation is also currently only equipped with a single transformer so does not provide a firm 11kV supply.

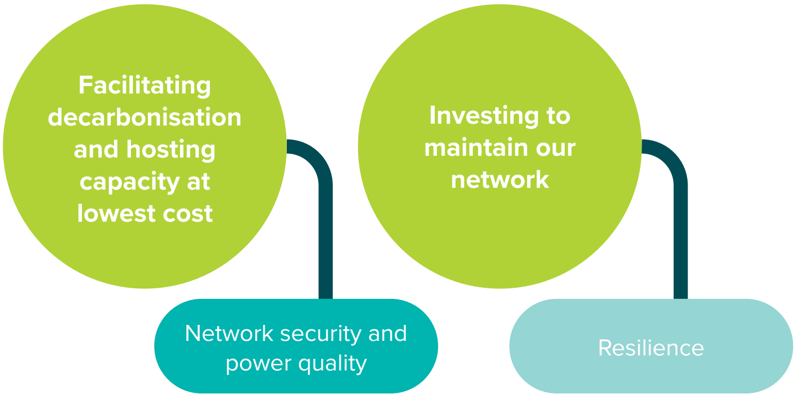
The rate of growth and the existing load at each of these sites makes generators and battery storage uneconomic as significant capacity would need to be replicated at each site. Technologies such as STATCOMs unlock thermal capacity in voltage constrained areas of the network, but do not provide real power capacity as required in the Northern Christchurch area.

Table 7.4.4 Northern Christchurch network capacity – HV major projects

<table>
<tr><th>No.</th><th colspan="2">Project title</th><th>Year</th><th>Business case existing (yes/no)</th></tr>
<tr><td rowspan="4">1174</td><td colspan="2">Belfast ZS 2nd transformer / network spare</td><td>FY26-27</td><td>No</td></tr>
<tr><td>Issue</td><td colspan="3">There is currently no network spare for the 40MVA 66/11kV power transformers.</td></tr>
<tr><td>Chosen solution</td><td colspan="3">Purchase and install second 40MVA 66/11kV power transformer for Belfast ZS to act as the network hot spare or provide a firm 11kV supply.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="3">This option provides both uninterrupted N-1 security of supply for the transformation at Belfast as well as providing a network spare transformer should one of the 40MVA transformers elsewhere in the network fault. All other options only provide one of these benefits.</td></tr>
<tr><td rowspan="4">491</td><td colspan="2">Belfast ZS to McFaddens ZS 66kV cable links</td><td>FY26-28</td><td>No</td></tr>
<tr><td>Issue</td><td colspan="3">The supplies to Dallington ZS, Rawhiti ZS and Waimakariri ZS have switchable N-1 security, and Belfast ZS only N security, at 66kV.</td></tr>
<tr><td>Chosen solution</td><td colspan="3">This project establishes 66kV cable links from Belfast ZS to Waimakariri ZS and from Marshland 66kV switching station to McFaddens ZS.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="3">Dallington ZS, Rawhiti ZS and Waimakariri ZS will have full N-1 security, and Belfast ZS switchable N-1, at 66kV on completion of this cable link project.</td></tr>
</table>

7.4.1.4 Region A subtransmission capacity

Investment drivers



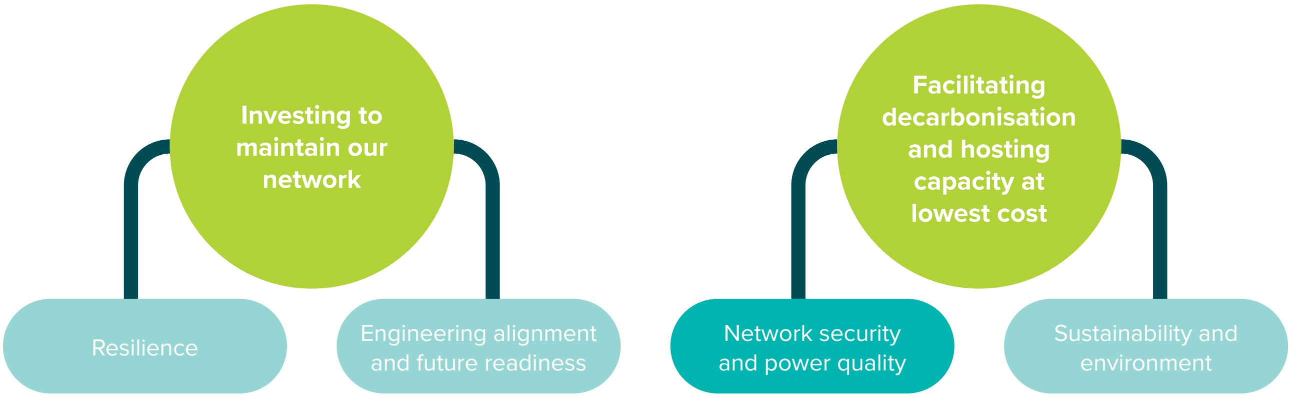
Our largest GXP, Islington 66kV, is forecast to meet or exceed its firm capacity at the end of the 10 year AMP period. We anticipate that as more fossil-fuelled process heating is converted to electric the capacity of Islington 66kV GXP will be reached sooner. Rather than putting more dependency on Islington 66kV GXP by introducing more capacity at this site, we will look at opportunities to increase our 66kV subtransmission resilience by strengthening ties to enable offload capability to adjacent GXPs. The projects in Table 7.4.5 enable Larcomb and Weedons ZSs to be offloaded and fed from the Norwood GXP by reinforcing the capacity of existing lines.

Table 7.4.5 Region A 66kV subtransmission capacity – HV major projects

No.	Project title		Year	Business case existing (yes/no)
1096	**Highfield ZS tee to Weedons ZS 66kV thermal upgrade**		**FY28**	**No**
	Issue	Islington GXP is approaching the N-1 limit. Weedons and Larcomb ZS cannot be offloaded due to a thermal constraint on an existing line section.		
	Chosen solution	To facilitate the offloading of Weedons and Larcomb ZS onto Norwood GXP the existing 66kV line from the Kerrs and Wards Rd intersection to Weedons ZS will be thermally uprated.		
	Remarks/alternatives	Re-rating the line can be achieved by minor clearance increases and is far more cost-effective than reconductoring the line as this would require the entire line to be rebuilt.		
1095	**Wards Rd 66kV line reconductor**		**FY28**	**No**
	Issue	The Norwood GXP – Highfield ZS – Burnham ZS 66kV ring is limited in its capability to carry Weedons and Larcomb ZS due to the existing overhead conductor on Wards Rd.		
	Chosen solution	Reconductor the 66kV line on Wards Rd to a larger capacity and re-rate to a higher maximum design temperature.		
	Remarks/alternatives	Expedites using spare Norwood GXP capacity to mitigate emerging Islington GXP constraint.		

7.4.1.5 Region B 66kV subtransmission capacity

Investment drivers



The capacity and resilience of the subtransmission supply to Region B is limited by the supply at Islington 66kV GXP, the limited amount of power generated from Trustpower's Lake Coleridge Power Station and the 66kV subtransmission capacity.

Continued residential and commercial growth in and around the townships of Rolleston and Lincoln, as well as growth from major customers is rapidly depleting the remaining capacity of the Region B 66kV subtransmission and is putting increasing pressure on the Islington 66kV GXP. A major customer in this area is also supplied from the Springston ZS to Hororata GXP Region B 66kV circuit, but is voltage drop and thermally constrained so cannot accept any more load.

The chosen solution to address all these capacity and resilience issues is to install a new 200MVA capacity 220/66kV GXP at Norwood. This new GXP is to be supplied from off the Transpower Islington-Livingstone 220kV circuit. The capacity of the new site was chosen to ensure consistency for spares availability across Orion's other 220/66kV GXP's. Other possible sites for the new GXP were considered but were determined to be less suitable due to their location relative to the Orion subtransmission and Transpower networks as well as their distance from the areas of load growth/constraint.

A new GXP also supports the growth likely to come from customers decarbonising process heat to electricity-based options and can also support the connection of utility scale solar PV in Region B.

Projects that form the Region B 66kV subtransmission capacity programme of works are outlined in Tables 7.4.6, 7.4.7 and 7.4.8.

Table 7.4.6 Region B 66kV subtransmission capacity – GXP projects

No.	Project title		Year	Business case existing (yes/no)
996	**Norwood GXP – new Region B 220/66kV substation**		**FY24**	**Yes**
	Issue	The 66kV capacity supplying Region B is becoming constrained due to rapid growth in this area, with the Western Loop forecast to exceed firm capacity around FY23.		
	Chosen solution	Install a new 200MVA capacity, dual transformer, 220/66kV GXP at Norwood that is supplied from the Transpower Islington-Livingstone 220kV circuit.		
	Remarks/alternatives	Construction of a new Region B GXP was the most cost-effective option from the Transpower Grid Reliability Standard (GRS) assessment. Two alternative GXP locations were also considered as part of our 'Region B subtransmission options' business case. Although this project is Orion initiated, it will be constructed, owned and operated by Transpower. It is already in construction and is scheduled for completion in FY24.		

Table 7.4.7 Region B 66kV subtransmission capacity – HV major projects

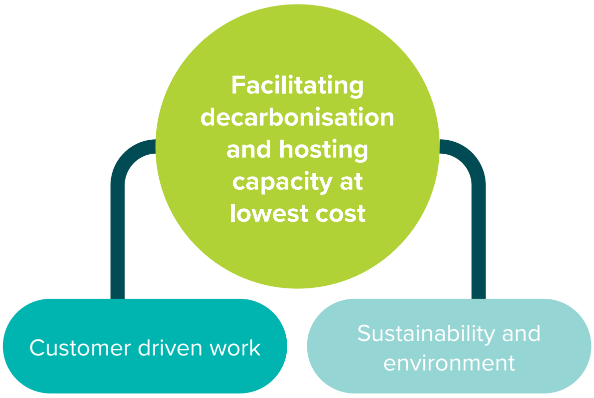
No.	Project title		Year	Business case existing (yes/no)
931	**Norwood ZS 66kV**		**FY22-24**	**Yes**
	Issue	The 66kV capacity supplying Region B is becoming constrained due to rapid growth in this area, with the Western Loop forecast to exceed firm capacity.		
	Chosen solution	Construct a new outdoor 66kV busbar to take bulk supply from the new Norwood GXP (Project 996).		
	Remarks/alternatives	We investigated constructing an indoor busbar similar to our Region A 66kV switching stations, but for this application it is significantly more cost-effective to build an outdoor yard (~30% less).		
940	**Dunsandel ZS to Norwood ZS 66kV line**		**FY22-24**	**Yes**
	Issue	The existing 66kV subtransmission network supplying Dunsandel ZS has no capacity available for any additional load growth.		
	Chosen solution	This project provides a direct 66kV connection between the new Norwood GXP (Project 931) and Dunsandel ZS.		
	Remarks/alternatives	This project forms one leg of the full N-1 66kV ring supply to Dunsandel ZS, refer to Project 941 for the Norwood – Brookside ZS 66kV line.		
941	**Brookside ZS to Norwood ZS 66kV line**		**FY23-25**	**Yes**
	Issue	Dunsandel ZS load has grown beyond the N-1 capability of the existing subtransmission network so an additional 66kV supply from Norwood ZS is required.		
	Chosen solution	This project provides a 66kV connection between Norwood ZS (Project 931) and Brookside ZS provides an uninterrupted N-1 supply to Dunsandel ZS and Killinchy ZS.		
	Remarks/alternatives	An alternative would be to double circuit the direct Norwood ZS to Dunsandel ZS 66kV line, but the chosen arrangement provides greater resilience through route diversity.		
953	**Norwood ZS 66kV line bays**		**FY26-27**	**No**
	Issue	66kV bays at Norwood 66kV need to be equipped to enable connection and supply of the Burnham ZS to Highfield ZS 66kV ring.		
	Chosen solution	This project completes the construction of three 66kV line bays at Norwood ZS to allow for the connection of the new 66kV lines to Highfield ZS, Burnham ZS and a bay for a 66/11kV transformer (Project 1070).		
954	**Highfield ZS 66kV line bays**		**FY27-28**	**No**
	Issue	Highfield ZS is currently fed on a 66kV spur supply and has only one 66kV CB there for the transformer protection, but the Norwood ZS to Highfield line requires switchgear to terminate into.		
	Chosen solution	This project installs two new 66kV line bays at Highfield ZS, and creates a new 66kV busbar, to allow for the connection of the new 66kV line from Norwood ZS.		
	Remarks/alternatives	The Highfield ZS was originally designed with future expansion to three 66kV CBs, but constructed with one.		
944 1071	**Burnham ZS to Norwood ZS 66kV circuit**		**FY27-28**	**No**
	Issue	To enable the new Norwood GXP capacity to be utilised and to provide a firm supply to Burnham ZS a new 66kV circuit is required between the Norwood and Burnham ZSs.		
	Chosen solution	These projects form a direct link from Norwood ZS to Burnham ZS via a 66kV cable out of Norwood ZS (Project 1071) and extended onto Burnham ZS with a new 66kV line (Project 944).		
	Remarks/alternatives	A 66kV cable is required for the first section because this part of the route is shared with the Norwood ZS to Brookside ZS 66kV line. Part of the 66kV line was partially formed as part of a supply upgrade project for the Burnham military camp.		

7.4 Investment plans continued

Table 7.4.8 Region B 66kV subtransmission capacity – HV minor projects				
No.	**Project title**		**Year**	**Business case existing (yes/no)**
1463	**Norwood ZS 11kV alteration**		**FY24**	**Yes**
	Issue	The new Norwood GXP / ZS requires a local 11kV supply.		
	Chosen solution	Rearrange and underground the 11kV circuits in and around the Highfield Rd and Telegraph Rd corner to faciliate the local supply and ensure that the circuits are configured for the future 66/11kV zone substation (Project 1070).		
	Remarks/alternatives	This project also aims to reduce the visual impact to the adjacent land owners and reduces the quantity of multi-circuit overhead lines.		

7.4.1.6 Customer driven projects

Investment drivers



The customer driven projects in Table 7.4.9 are large connections requiring subtransmission or zone substation capacity upgrades. All these customer driven projects support our customers in reducing their carbon emmissions.

Table 7.4.9 Customer driven projects – HV major projects

No.	Project title		Year	Business case existing (yes/no)
1237	**Brookside ZS upgrade (stage 1)**		**FY24**	**Yes**
	Issue	A customer connection adjacent to the Brookside ZS requires a large capacity 11kV connection, but there are no spare 11kV switches available.		
	Chosen solution	The connection capacity requires an additional 11kV circuit breaker to be added to the 11kV switchboard at Brookside ZS to facilitate the connection while simplifying the metering requirements.		
	Remarks/alternatives	Other associated works are required to enable space for the extension to occur.		
1266 1267	**Brookside ZS upgrade (stages 2 and 3)**		**FY24-27**	**Yes**
	Issue	The proposed Stage 2 and 3 of a customer development exceeds the capability of the existing power transformer at Brookside ZS.		
	Chosen solution	We propose to expand the Brookside ZS 66kV switchyard to provide the Stage 2 and 3 connections via two new power transformers.		
	Remarks/alternatives	These projects facilitate the connection of the new Norwood to Brookside ZS 66kV line (Project 941) into a separate 66kV bay. Stage 2 will utilise the capacity of the Springston ZS to Brookside ZS 66kV line upon completion of Norwood GXP.		
1275	**Dunsandel ZS 66kV tee-off**		**FY25-26**	**No**
	Issue	A customer requires a large capacity connection, but the existing 11kV distribution has limited capacity.		
	Chosen solution	The customer will be connected at 66kV via a new tee-off from the Dunsandel ZS to Norwood ZS 66kV line (Project 940).		
	Remarks/alternatives	The timing of this project is tentative and is dependent on the customer.		

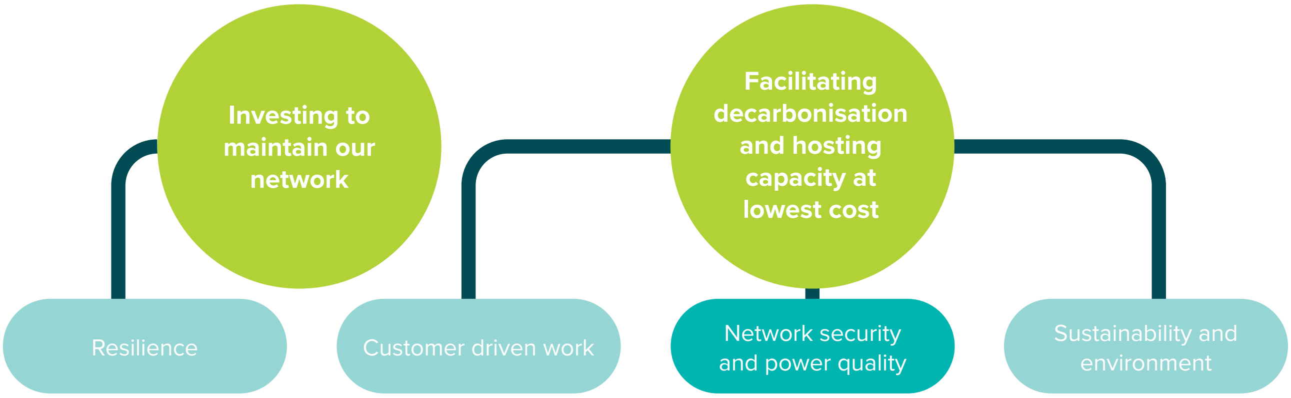
7.4 Investment plans continued

Table 7.4.9 Customer driven projects – HV major projects (continued)				
No.	**Project title**		**Year**	**Business case existing (yes/no)**
1070	**Norwood 66/11kV zone substation**		**FY26-27**	**No**
	Issue	An existing major customer is increasing their load beyond the existing 11kV distribution capacity between Highfield ZS, Rolleston ZS and Greendale ZS.		
	Chosen solution	The chosen solution is to construct an 11kV point of supply at Norwood ZS (Project 931) by installing a 66/11kV transformer and 11kV switchboard at the Norwood site to feed in to the surrounding 11kV network.		
	Remarks/alternatives	A large contributor to the major customer load increase is the conversion of coal to electric heat pump process heating.		

Table 7.4.10 Customer driven projects – HV minor projects				
No.	**Project title**		**Year**	**Business case existing (yes/no)**
1119	**Runners Rd 11kV feeder**		**FY24**	**Yes**
	Issue	The Burnham military camp requires an increase in its supply capacity above the capability of the existing network.		
	Chosen solution	A new direct cable connection to be laid from Rolleston ZS to Burnham military camp.		
	Remarks/alternatives	We investigated constructing a new overhead connection, but the supply requirements exceed the capabilty of our standard 11kV overhead feeder construction. The increased load is due to decarbonisation plans and the military base expanding.		

7.4.1.7 Lincoln area capacity and resilience improvement

Investment drivers



High residential subdivision growth in the Lincoln township has pushed the peak load of Lincoln ZS beyond the firm capacity by approximately 0.5MVA.

By FY32 this load is forecast to be approximately 120-160% of the site's firm capacity. Springston ZS also provides support for the Lincoln township and due to additional commercial growth, is forecast to breach its capacity in FY24. If unaddressed, this situation puts the area at risk of a cascade failure, black-out fault, during peak load times.

We have an active request for proposals for non-network flexibility solutions to ensure we can maintain the network security of supply to Lincoln. Through a flexibility solution we hope to reduce the impact of peak loads to defer the construction of the new Greenpark zone substation.

The projects in Table 7.4.11 address the short to medium term issues with upgrades to Springston ZS. The Lincoln township is growing away from both Springston and Lincoln ZS so in the longer-term a new Greenpark zone substation is forecast to be built on the eastern side of the township. The programme also incorporates various subtransmission enabling projects to reinforce the network into Greenpark ZS.

Table 7.4.11 Lincoln area capacity and resilience improvement – HV major projects

No.	Project title		Year	Business case existing (yes/no)
728	**Springston ZS 11kV switchboard extension**		**FY23-24**	**Yes**
	Issue	At Springston ZS additional 11kV circuit breakers are required to connect the new 66/11kV transformer (Project 894).		
	Chosen solution	This project extends the 11kV CB's installed in FY18 to terminate the new transformer and provide additional feeders.		
	Remarks/alternatives	The 11kV CBs located within the modular building will be decommissioned as part of this project.		
894	**Springston ZS 2nd 66/11kV transformer bank**		**FY23-24**	**Yes**
	Issue	The excess capacity available at Springston ZS to provide contingency support to the neighbouring Lincoln, Rolleston and Brookside zone substations is diminishing due to sustained residential household and the university growth. Lincoln ZS and Springston ZS provide support for each other during major N-1 events, but by FY26 the total load of these substations is forecast to be in-excess of their combined N-1 rating (20MVA).		
	Chosen solution	We will increase the capacity by installing a second 66/11kV transformer and additional 66kV CB bay.		
	Remarks/alternatives	Upgrading the Lincoln ZS transformers is not practical and the addition of the second bank at Springston ZS upgrade defers the immediate need to construct the Greenpark ZS.		

7.4 Investment plans continued

Table 7.4.11 Lincoln area capacity and resilience improvement – HV major projects (continued)

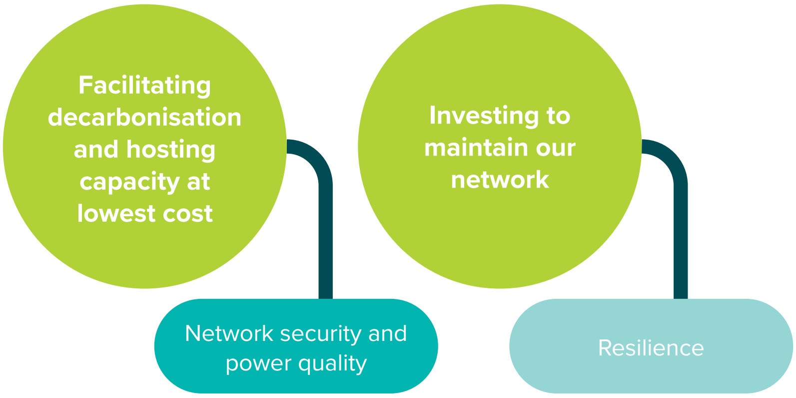
No.	Project title		Year	Business case existing (yes/no)
1099	**Springston ZS 66/11kV transformer upgrade**		**FY24-25**	**Yes**
	Issue	In FY24 a second 66/11kV transformer will be added to Springston ZS, but this won't provide any usable increase in firm capacity due to the original transformer bank being only 10MVA in size. The load at Lincoln University and Lincoln township has exceeded the N-1 capacity.		
	Chosen solution	Change the existing T3 66/11kV 10MVA transformer to a new 11.5/23MVA transformer.		
	Remarks/alternatives	This upgrade defers the need to construct the Greenpark ZS.		
1080	**Springston to Lincoln ZS 66kV line reconductor**		**FY27**	**No**
	Issue	An existing 33kV operated overhead section, constructed on Shands and Boundary Roads, from Springston ZS to Lincoln ZS does not have sufficient capacity to supply Greenpark ZS (Project 842).		
	Chosen solution	Reconductor the line to a higher capacity conductor.		
	Remarks/alternatives	This pole line has already been rebuilt to 66kV construction as part of an asset lifecycle refurbishment project.		
1084	**Edward St to Greenpark ZS 33kV cable**		**FY28-29**	**No**
	Issue	The Greenpark ZS requires an additional 33kV subtransmission circuit to have the full 23MVA capacity.		
	Chosen solution	Cut ex Springston ZS to Lincoln ZS 33kV cable and joint onto OOS 33kV cable on Edward St. Extend OOS 33kV cable to Greenpark ZS.		
	Remarks/alternatives	The OOS cable was installed as part of an 11kV reinforcement project in FY21.		
842	**Greenpark 33kV zone substation**		**FY28-29**	**No**
	Issue	With continued residential growth east of Lincoln ZS, the zone subs firm capacity is exceeded and it becomes impractical to do further reinforcement back to Springston ZS to be able to carry the load.		
	Chosen solution	Construct a new 23 MVA firm capacity 33kV zone substation on the eastern edge of Lincoln township to replace the existing Lincoln ZS.		
	Remarks/alternatives	There is no ability to upgrade the firm capacity at Lincoln ZS due to space constraints. This project may be deferred pending the outcome of the non-network solution request.		

Table 7.4.12 Lincoln area capacity and resilience improvement – HV minor projects

No.	Project title		Year	Business case existing (yes/no)
806	**Gerald Street 11kV cable**		**FY26**	**No**
	Issue	There is currently approximately 400m of 11kV overhead remaining on Gerald Street in Lincoln. This limits the capacity of the feeder, reduces the reliability for the Lincoln township customers fed from this feeder.		
	Chosen solution	The remaining 11kV lines in Gerald Street (Lincoln) will be undergrounded as the sequence of reinforcement is completed.		
	Remarks/alternatives	This project is part of our reinforcement of the main road circuits in Lincoln township, including the removal of 11kV overhead high voltage lines and will be coordinated with Selwyn District Council works on and around Gerald Street.		

7.4.1.8 Rolleston area capacity and resilience

Investment drivers



The Rolleston area has experienced rapid load growth due to the township residential and industrial subdivision growth. This growth has pushed the Rolleston ZS beyond its firm capacity and most practical 11kV load transfers to the supporting zone substations at Larcomb and Weedons have been exhausted.

This programme of works addresses the local Rolleston township 11kV distribution capacity with the establishment of a new higher capacity substation to replace Rolleston ZS, named Burnham ZS, and through strengthening the network back to Springston ZS. The 11kV distribution capacity into the Izone industrial area is also being addressed with the creation of an 11kV switching station that will be supplied by the new Burnham ZS.

The current subtransmission supplying Rolleston township is operating at 33kV so this programme also establishes the new higher capacity 66kV network by reinsulating some of the 33kV lines to 66kV to supply the new Burnham ZS. In the short-term we will supply Burnham ZS from the Islington GXP before being later transferred over to the new Norwood GXP (Projects 944, 953, 954 and 1071).

Due to the rate Rolleston's growth we have had to accelerate the construction of Burnham ZS, but will build it in stages over three years to manage the delivery.

Table 7.4.13 Rolleston area capacity and resilience – HV major projects

<table>
<tr><th>No.</th><th colspan="2">Project title</th><th>Year</th><th>Business case existing (yes/no)</th></tr>
<tr><td rowspan="4">934</td><td colspan="2">Walkers Rd 66kV line conversion</td><td>FY24-25</td><td>Yes</td></tr>
<tr><td>Issue</td><td colspan="3">The overhead 33kV conductor between Highfield ZS and Rolleston ZS has progressively been upgraded to 66kV construction in anticipation of operation at 66kV.
However, there is a small section remaining down Walkers Rd that has yet to be upgraded.</td></tr>
<tr><td>Chosen solution</td><td colspan="3">This project converts the remaining 33kV line construction, down Walkers Rd, between Two Chain Rd and Kerrs/Wards Rd, to 66kV construction.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="3">This project coordinates with other projects to meet the requirement of creating a 66kV ring to the new Burnham ZS.</td></tr>
<tr><td rowspan="4">1000</td><td colspan="2">Burnham ZS to Dunns Crossing Rd north 66kV cable</td><td>FY24-25</td><td>Yes</td></tr>
<tr><td>Issue</td><td colspan="3">The area surrounding the proposed Burnham ZS is becoming urbanised with residential housing and a school in close proximity. The existing 66kV constructed line down Dunns Crossing Rd needs to be diverted down Burnham School Rd into Burnham ZS.</td></tr>
<tr><td>Chosen solution</td><td colspan="3">This project is a new 66kV cable circuit to connect the new Burnham ZS onto the O/H line running down Dunns Crossing Rd to provide one leg of the ring supply back to Islington GXP.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="3">An overhead line option was considered but is not suitable due to the proximity of the school and houses.</td></tr>
</table>

Table 7.4.13 Rolleston area capacity and resilience – HV major projects (continued)

No.	Project title		Year	Business case existing (yes/no)
639	**Burnham ZS – new 66/11kV substation**		**FY24-26**	**Yes**
	Issue	The load growth in the Rolleston/Izone area has caused the 11kV firm capacity of Rolleston ZS to be exceeded and the upper network capacity is also reaching the firm capacity.		
	Chosen solution	A new 66/11kV 23MVA capacity Burnham ZS will be built to replace the 33/11kV 10MVA capacity at Rolleston ZS. Part of the 11kV switchboard will be located at Rolleston ZS and supplied via 11kV incomers from Burnham ZS.		
	Remarks/alternatives	Upgrading Rolleston ZS to 23MVA utilising the existing 33kV supply was investigated but was found to be unsuitable due to space constraints. Burnham ZS has been designed to facilitate the future installation of a third 23MVA transformer if the load continues to grow (Project 1453).		
1002	**Burnham ZS to Dunns Crossing Rd south 66kV cable**		**FY25-26**	**Yes**
	Issue	To meet appropriate security of supply requirements, a second 66kV circuit heading east out of Burnham ZS is required to connect to the 66kV overhead line heading south down Dunns Crossing Rd.		
	Chosen solution	This project is the installation and commissioning of a new 66kV cable down Burnham School Rd from Burnham ZS to Dunns Crossing Rd to establish a full N-1 supply.		
	Remarks/alternatives	This project as well as Project 987 will provide the second 66kV connection to Burnham ZS by teeing into the Larcomb to Springston ZS 66kV line.		
987	**Springston Rolleston Rd 66kV line**		**FY25-26**	**Yes**
	Issue	The new Burnham ZS requires an N-1 supply.		
	Chosen solution	The majority of the existing overhead subtransmission from Springston to Rolleston ZS has been rebuilt to 66kV construction as part of a lifecyle replacement programme so this project converts the last required section from 33kV construction to 66kV as well as a larger capacity conductor.		
	Remarks/alternatives	This is the most cost-effective solution to provide the N-1 connection to Burnham ZS. This project utilises a tee connection into the Larcomb to Springston ZS 66kV line rather than requiring an additional 66kV bay at Springston ZS.		
1088	**Weedons Rd 33kV cable**		**FY25-26**	**Yes**
	Issue	To maintain the 33kV support from Springston ZS to Shands ZS once the Selwyn Rd 33kV network is disestablished a new 33kV cable is required.		
	Chosen solution	The cable will be laid from the corner of Weedons Rd and Lincoln Rolleston Rd to the corner of Weedons Rd and Selwyn Rd.		
637	**Railway Rd 11kV switching station**		**FY26-27**	**No**
	Issue	The load in the Rolleston industrial park continues to grow and we have almost exhausted the 11kV capacity from Larcomb and Weedons ZSs.		
	Chosen solution	We propose that a new 11kV switching station will be supplied from Burnham ZS via two 11.5MVA feeders.		
	Remarks/alternatives	The potential magnitude of the future loads, plus the ongoing growth around Rolleston, meant that a new zone substation was considered as an option. The fact that there are three nearby substations with sufficient capacity and that the 11kV feeders to adjacent substations in this project would still be needed for contingent support, means an 11kV solution is more cost effective and makes more efficient use of existing assets in the short to medium term.		
1453	**Burnham ZS 3rd transformer**		**FY32-33**	**No**

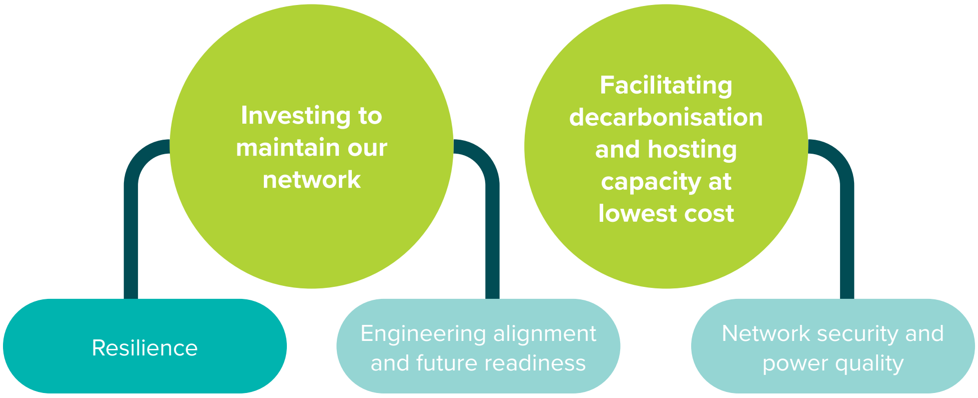
7.4 Investment plans continued

Table 7.4.14 Rolleston area capacity and resilience – HV minor projects

No.	Project title		Year	Business case existing (yes/no)
1097	**Springston to Rolleston 11kV reinforcement**		**FY24**	**Yes**
	Issue	The subdivision growth on the south end of Rolleston has stretched the 11kV capacity to the point where reliability is being affected due to the length and number of customers of radial 11kV feeders.		
	Chosen solution	This project lays two new feeders from Springston ZS to reinforce the supply to the south border of the Rolleston urban area.		
	Remarks/alternatives	This project provides greater resilience to Springston, Larcomb and Rolleston ZSs.		
1458	**Dunns Crossing 11kV reconfiguration**		**FY24**	**Yes**
	Issue	The existing 11kV network on Dunns Crossing Rd requires reconfiguration to ensure that the capacity from Burnham ZS can be utilised.		
	Chosen solution	This project splits up some of the trunk feeders and installs new circuits that form the start of Railway Rd 11kV feeders (Project 638).		
	Remarks/alternatives	This project is being coordinated with the Runners Rd 11kV feeder (Project 1119) to ensure that the trench sharing opportunities are maximised.		
1101	**Burnham 11kV reconfiguration**		**FY25-26**	**Yes**
	Issue	Once the subtransmision in Rolleston is all converted to 66kV to supply the new Burnham ZS (Project 639) the existing Rolleston ZS will lose its supply.		
	Chosen solution	This project lays large capacity 11kV feeders from the Burnham ZS to create new 11kV incomers to Rolleston ZS to operate as a remote 11kV switchboard. Complete the reconfiguration of the Rolleston/Burnham feeders that was begun as part of Project 1458.		
	Remarks/alternatives	This project has two stages whereby the incomer on the north side of the road is established first and the second incomer in the following year to aid constructability.		
638	**Railway Rd 11kV – stage 2 cabling**		**FY27**	**No**
	Issue	The 11kV cable capacity into and around the Rolleston industrial subdivison is exhausted.		
	Chosen solution	Extend the cables installed on Dunns Crossing Road as part of Project 1458. The route will be along Two Chain Rd and on to the new Railway Rd substation (Project 637).		

7.4.1.9 Hororata GXP capacity and resilience

Investment drivers



The Hororata 33kV GXP has reached the firm capacity due to the increased loading from the Central Plains Water irrigation scheme. The Hororata GXP is also susceptible to large voltage excursions which cause sensitive customer loads to disconnect if a tripping occurs on either of the Islington to Kimberley to Hororata GXP lines. Therefore, any reduction of load will benefit the overall post-contingency voltage stability. This GXP does not have a 66kV bus coupler so is exposed to single bus faults causing complete outages to the 66kV and 33kV Orion load and the connection through to Coleridge GXP.

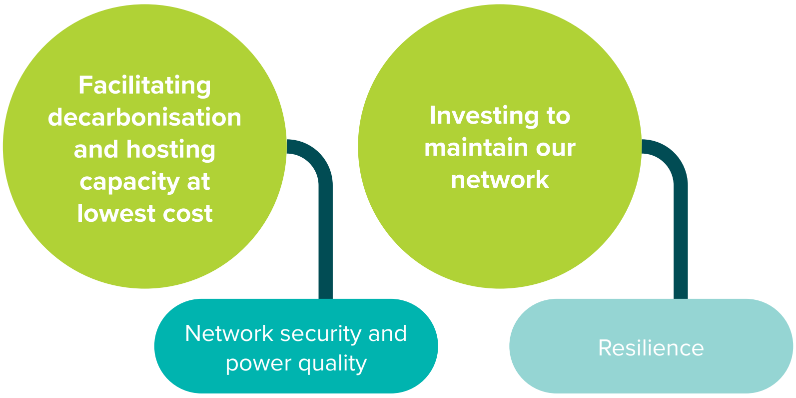
The projects in Table 7.4.15 reduce the dependency on the Hororata GXP by creating new 66kV connections to Norwood GXP. The existing 33kV outdoor bus is to be replaced with a new indoor bus to increase the reliability.

Table 7.4.15 Hororata GXP capacity and resilience – HV major projects

No.	Project title		Year	Business case existing (yes/no)
1064	**Hororata ZS 33kV site redevelopment**		**FY26-27**	**No**
	Issue	The present Orion Hororata ZS is a combination of the ex-Central Canterbury Power Board and ex-Transpower assets spread across two switchyards. All seven bays of switchgear are due for replacement and the existing bus layout does not meet current design standards or operator safety clearances.		
	Chosen solution	The existing 33kV circuit connections will be split between a new indoor 33kV switchgear building and a new 66kV rated outdoor busbar.		
	Remarks/alternatives	The site concept design is with a view to creating a future Orion 66kV busbar to faciliate connections to Norwood GXP, but will be initially operating at 33kV.		
1086	**Norwood ZS 66kV bays for Creyke Rd and Greendale ZS's**		**FY29-30**	**No**
1087	**Greendale ZS 66kV bays**		**FY29-30**	**No**
1072	**Norwood ZS to Greendale ZS 66kV line**		**FY29-30**	**No**
1525	**Wards Rd, Darfield 66kV line**		**FY30**	**No**
1245	**Norwood ZS to Creyke Rd ZS 66kV cable**		**FY30-31**	**No**
1073	**Norwood ZS to Creyke Rd ZS 66kV line**		**FY29-31**	**No**
1459	**Creyke Rd ZS – new 66/11kV substation**		**FY30-31**	**No**

7.4.1.10 Other projects

Investment drivers



This set of projects are reconfigurations or reinforcements of the subtransmission and 11kV distribution system across the Orion network. These are identified through our ongoing monitoring of 11kV feeder loadings and regular review of our zone substation contingency plans.

Table 7.4.16 Other projects – HV major projects

No.	Project title	Year	Business case existing (yes/no)
1444	**Islington to Halswell ZS 66kV tower line alteration**	**FY24**	**Yes**
	Issue: The tower line circuits require lifting over the Owaka pit due to clearance issues.		
	Chosen solution: This project covers the installation of a new pole to replace two towers.		
1246	**Brookside / Killinchy ZS to Southbridge ZS 66kV line**	**FY31-32**	**No**
610	**Southbridge 66kV substation**	**FY31-32**	**No**
1054	**Ilam ZS 11kV incomer cables**	**FY32-33**	**No**

7.4 Investment plans continued

Table 7.4.17 Other projects – HV minor projects

No.	Project title		Year	Business case existing (yes/no)
1452	**Port Hills Road 11kV reinforcement**		**FY24**	**Yes**
	Issue	The existing 11kV cable between Port Hills Rd No.272 and Lock Pl No.16 is constraining the secondary network in the area. This is due to recent upgrades on Port Hills Rd for a number of major customers.		
	Chosen solution	Lay a new high capacity 11kV circuit and reconfigure the secondary network to enable full utilisation of the new circuit.		
	Remarks/alternatives	The existing overhead 11kV along same route as new circuit will also be undergrounded.		
913	**Heathcote Lyttelton 11kV reconfiguration**		**FY26**	**No**
	Issue	In FY20 a new cable was installed through the Lyttelton road tunnel to increase the supply resilience to the township of Lyttelton and the port. Presently the full capacity of the cable cannot be utilised due to the network configuration on the Heathcote side of the supply.		
	Chosen solution	This project is to install and commission new switchgear and reconfigure the 11kV network on the Heathcote supply side of the tunnel cable.		
	Remarks/alternatives	This project installs equipment on an existing Orion site and is the most cost effective solution to make use of the full capacity of the new 11kV through the tunnel.		
1093	**Innovation Drive 11kV reconfiguration**		**FY26**	**No**
	Issue	Load growth in the Calder Stewart and Ngai Tahu commercial and industrial subdivisions in between Main South Road and Shands Road is stretching the existing distribution capacity between Moffet ZS and Hornby ZS. Part of original distribution design for the area no longer matches the trunk feeder architecture due to changes in customer requirements.		
	Chosen solution	This project will reconfigure some cables on Innovation Drive so that the feeders better align with the trunk feeder architecture and allow for the future commercial and industrial growth in the area.		
	Remarks/alternatives	This is the most cost effective solution to provide capacity for the future commercial and industrial growth in the area.		

7.4.2 LV programmes of work

The following section outlines our Network Development LV projects and programmes of work planned for the next 10 years. With ongoing residential housing intensification in Christchurch and electric vehicles and photovoltaic generation become more economical, the capability of our LV network is becoming increasingly important.

Our investment strategy for our LV network is to use new information and technology to optimise the throughput of energy across our existing network, reducing the need to reinforce it.

The new information on our LV network will come from two primary sources. Capital investment in LV monitoring, see Section 7.4.2.1, and receiving network data from the owners of smart meters. For more detail on these measures, see Section 5.3.2, and for the operating expenditure associated with smart meter data gathering, see Section 9.

To optimise our LV network we will use smart systems to assess the information our low voltage network's electrical flows down to LV feeder level and dynamically alter the loadings on these feeders to increase their usable capacity. This smart new technology will release currently latent and unused capacity from the network and optimise utilisation of an existing LV feeder. The released network capacity can be used to connect more EVs and new housing, without building new, expensive network.

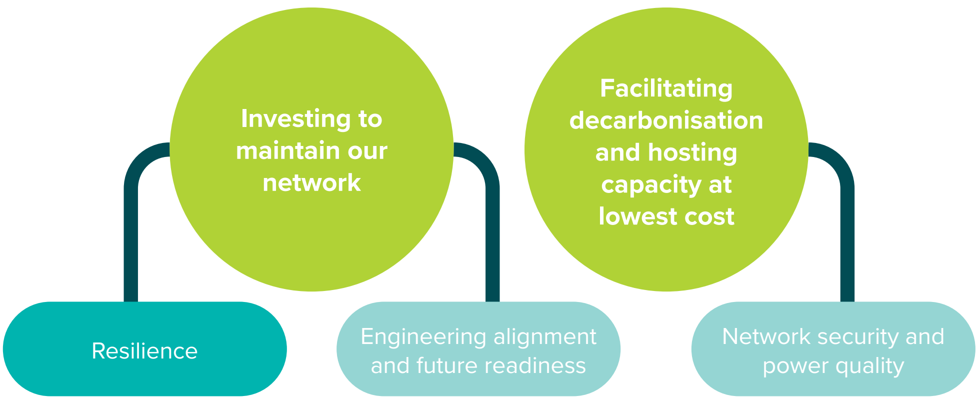
We will also use other methods to ensure new low voltage network isn't unnecessarily built, including:

- increasing the maturity of our future energy scenarios and modelling capability to improve our confidence in future demand, flexibility, and network constraints
- incentivising our customers and communities to help alleviate network constraints using energy storage and demand side flexibility - where lower cost than network augmentation
- encouraging the best use of vehicle-to-grid and vehicle-to-home technology for electric vehicles will the goal of lowering network peaks or solving other network constraints like voltage issues
- using non-traditional network solutions, like Statcoms for voltage regulation, as a lower cost solution to traditional capacity upgrades

Through a combination of approaches, we will get the most out of our assets and minimise the investment required in our traditional low voltage network. The proactive LV reinforcement investment that will still be required, given the sheer size of demand increase from EVs, population growth, and intensification of housing, is described in Section 7.4.2.2.

7.4.2.1 LV monitoring

Investment drivers



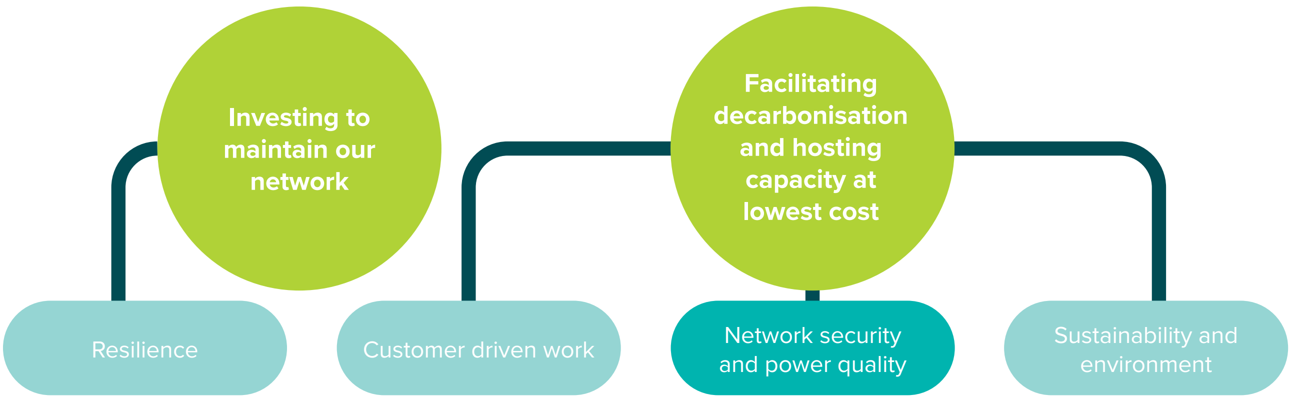
To increase the visibility and understanding of our LV networks, we are in the process of installing approximately 1,600 LV monitors by FY26. These monitors are being targeted towards sites with a higher risk of constraint, as forecast by the research we have completed with the EPECentre. This number of monitors approximates to 13% of the total number of transformers on our network, and therefore aligns with the 'expansion scenario' described by Sapere Consulting in their 'Low Voltage Monitoring' guideline document produced for the Electricity Networks Association (ENA) in 2020.

Table 7.4.18 LV monitoring

No.	Project title		Year	Business case existing (yes/no)
884	**Low voltage monitoring programme**		**FY20-26**	**Yes**
	Issue	New technologies such as photovoltaic (solar) generation, battery storage and electric vehicles have the potential to significantly change customer behaviour and we currently have very limited real-time visibility of our low voltage network, making it difficult to identify potential constraints.		
	Chosen solution	We have initiated a programme of works to install LV monitors at strategic locations on our LV network so that we can better respond to and understand the potential change of customer behaviour.		
	Remarks/alternatives	To maximise efficiency, the equipment will be only installed at higher risk distribution substations that serve more than one customer and have a minimum rating of 100 kVA for pole mounted sites or 200 kVA for ground mounted sites.		

7.4.2.2 Proactive LV reinforcement

Investment drivers



LV network issues are currently not easy to identify due to high volume, low visibility and data gaps which make it difficult to model on a regular basis. Operating within these current limitations we have formulated a threshold-based system to classify LV constraints into low, medium, and high priority. That system has generated our present LV reinforcement programme. As our LV data strategy comes to life, it is envisaged that LV constraints will be investigated in detail on a targeted area by area basis, in order to develop project scopes for each reinforcement. During these investigations, model results will be further verified using LV monitoring data, where available, and other techniques before network upgrades are initiated.

Table 7.4.19 Proactive LV reinforcement

No.	Project title		Year	Business case existing (yes/no)
1277	**Proactive LV reinforcement programme**		**FY24-33**	**Yes**
	Issue	Modelling of the LV network indicates that there are several constraints existing which will be exacerbated by EV load and housing infill.		
	Chosen solution	Investigate issues and initiate proactive reinforcements to reinforce areas of the network which have been identified as constrained.		
	Remarks/alternatives	Where possible, non-network solutions will be implemented, such as network switching, phase balancing and voltage support. The feasibility of these solutions will be determined on a case by case basis.		

7.4.3 Distributed Energy Resource Management alternatives

Distributed Energy Resource Management (DERM) initiatives can provide alternatives to investment in traditional network development solutions. This section is included in our AMP to assist potential DERM providers to determine the approximate magnitude and location of specific projects proposed that could be deferred through DERM.

Table 7.4.21 is a high-level assessment of the approximate magnitude and timing where DERM could be used to defer the project. If a DERM solution is presented, further detailed analysis is undertaken to compare options.

For example:

Burnham zone substation alternative needs to provide for a 4,300kW security breach and 300kW of annual load growth. For a DERM solution to be economic it needs to provide at least one-year deferral of a network solution.

Over the next few years, we anticipate our communication of where DERM alternatives will be useful will be considerably enhanced.

Presently we are trialling competitive procurement of non-network solutions for defined projects. In the future we hope to have mature procurement processes that actively test network solutions against those offered by external providers, with a view to working collaboratively with DER owners and aggregators to optimise network performance for least overall cost.

To achieve this, we will look to provide extensive network information electronically to DER owners and aggregators – potentially identifying real time opportunities for network alternatives.

Distributed Energy Resource Management (DERM) initiatives can provide alternatives to investment in traditional network development solutions.

Table 7.4.20 Distributed Energy Resources Management capacity for non-network alternatives

No.	Project description	Season	Year	Base constraint (kW)	Growth per year (kW)
1070	Norwood 66/11kV zone substation	Summer	FY25	4,500	–
639	Burnham 66/11kV zone substation	All	FY25	4,500	300
919	Halswell ZS 3rd transformer and 11kV switchgear	Winter	FY26	–	1,500
1524	Halswell area 11kV reinforcement				
842	Greenpark 33/11kV zone substation	Summer	FY26	–	750
1080	Springston to Lincoln ZS 66kV line reconductor				
1084	Edward St to Greenpark 33kV cable				

8

Supporting our business

Photo: Vicky Ross, a member of Orion’s Procurement and Land Services Team.

Contents

8.1 Introduction

In this section we describe the work of the teams in Orion that together, enable our business to function and what each team does. We also describe our corporate properties and the information systems that support the operation of our network and our administrative functions. At the end of this section we describe the fleet of vehicles we use to do our work and engage with the community.

8.2 Gearing up for the future

The growing impacts of climate change, the increased pace of decarbonization and rapid innovation in the energy sector are stimulating more conversations about the future of our service to customers than ever before.

To deliver on our Purpose to: Power a cleaner and brighter future with our community we are gearing up our business to meet the challenges and opportunities presented by a more connected and interactive energy future.

Being more agile and responsive to our customers' changing expectations calls for new systems, processes, and capabilities. Orion needs to make decisions informed by intelligent analysis of the data available to us, and ensure our operations are performing as efficiently and effectively as possible.

A key area of focus for Orion is upgrading and developing new systems and processes and this plan reflects significant investment to lift our asset management platforms to state of the art levels.

We are also focused on extending our use of data and digitisation to deepen our understanding of how customers are using our network. These insights will help us to optimize our business processes, inform system and platform development and engage in new ways with our customers. Our step-change in Orion's use of data and digitisation will deliver greater operational efficiency and better outcomes for our customers.

To make the most of new systems and processes, we are developing our business capability by investing in our people. We are accelerating our human capability by implementing a new performance management programme, EmPowered, to drive performance, engagement, and capability development. We have also established new roles and brought on board people with different skills and expertise to assist us to develop new ways to support our customers and community.

The changes we are making to adapt to the needs of the future, mean Orion's non-network operational expenditure is 1.5 times more than last year's forecast. This increase reflects increased expenditure on:

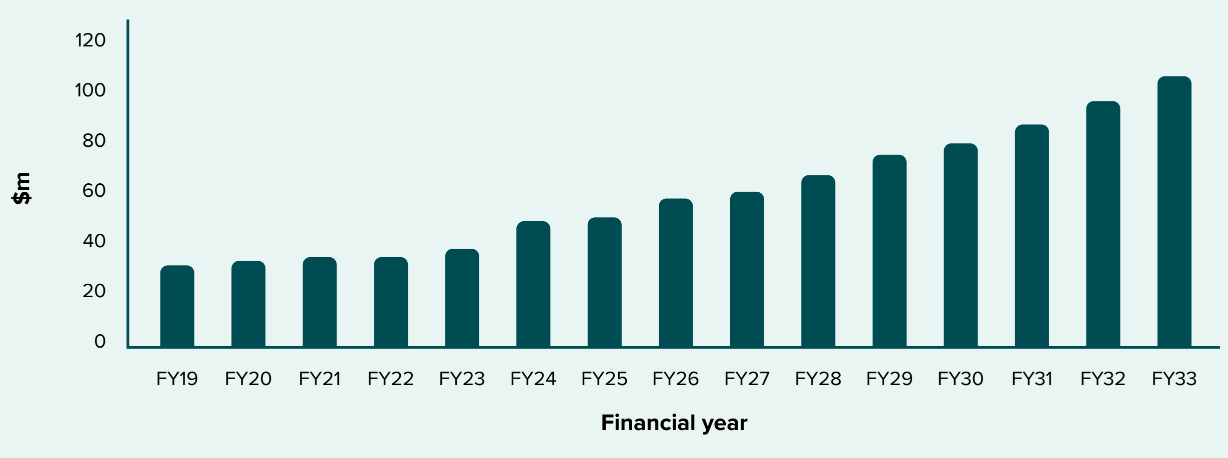
- system operations and network support team opex
- business support team opex
- a range of data, digitisation systems that support operation of our network

We expect the efficiencies gained from greater investment in data, digitisation, and improved systems and processes will assist us to deliver our forecast increase in capital expenditure of around 260% over the AMP period.

Our future non-network operational expenditure also makes some allowance for flexibility reward payments to our customers. This expenditure, paid at lower cost than the alternative cost of building new network, is a type of expenditure that hasn't previously occurred.

For our forecast increase in operational expenditure, see Figure 8.2.1. Further detail on expenditure is provided in Section 9.

Figure 8.2.1 Historic and forecast non-network operational expenditure (real) – $000



8.2 Gearing up for the future

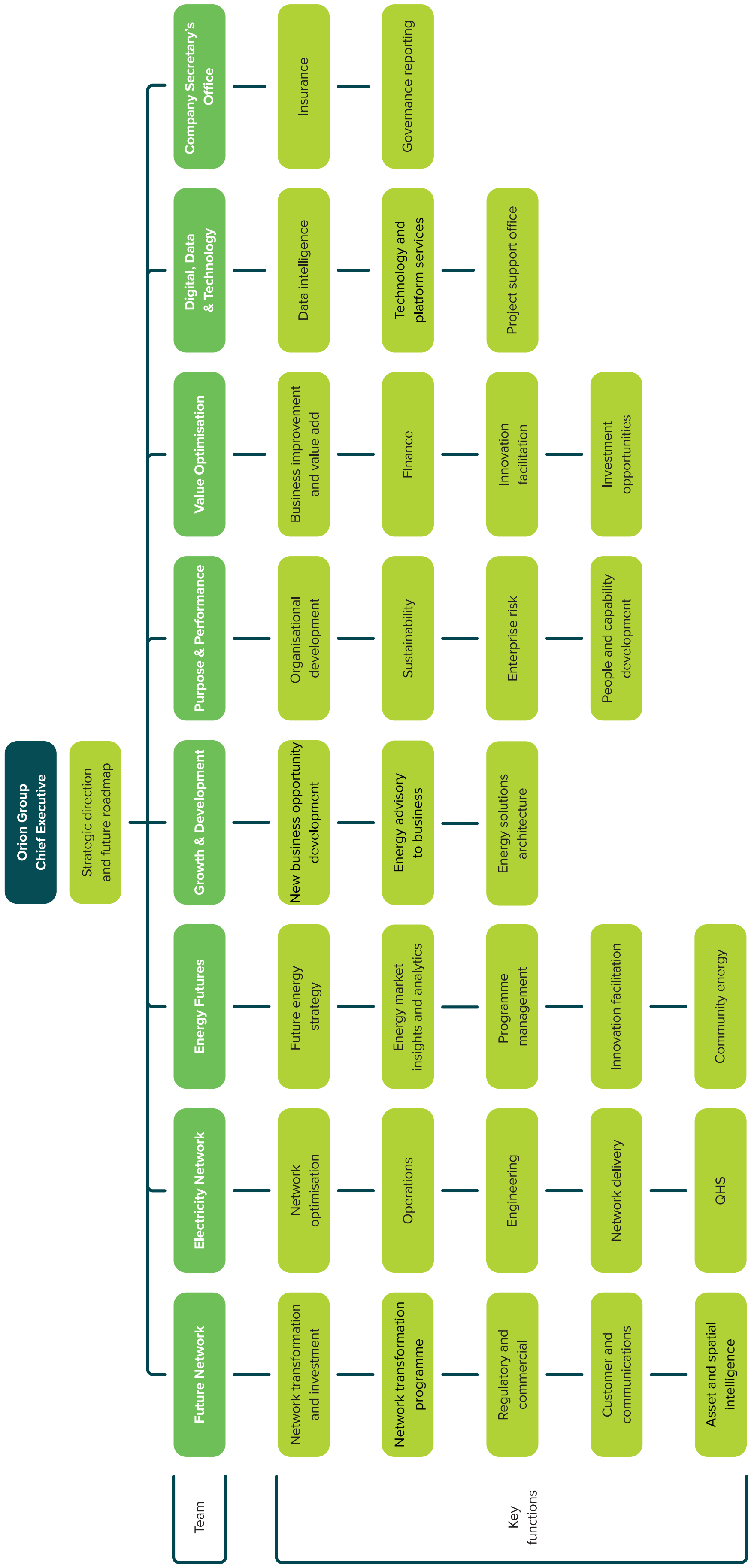


Figure 8.2.2 Organisation structure

8.2 Gearing up for the future continued

The Commerce Commission defines two categories for people-related opex: System Operations and Network Support, and Business Support. The balance of this section is split between these two categories. This means that activities may appear in either one or both of the Commission's categories. We will use cost allocation to account for roles and services that are not part of the regulated service.

8.3 System operations and network support teams

The system operations and network support activity area covers the teams managing our network, including our Customer Support team and office-based system operations teams. Around 75% of our people are in this activity area.

8.3.1 Future Network

The future network group is responsible for the overall direction and management of our network infrastructure.

It is responsible for strategic and engineering planning for Orion's electricity distribution network, and our customer service activity, infrastructure stewardship, regulation, pricing and billing support.

There are four teams in the group that deliver system operations and network support activity:

Network transformation and investment team:

- documents our network development plans and forecasts and articulates this through production and publishing of a 10 year asset management plan
- develops appropriate whole of life strategies for our network assets
- monitors, analyses and reports on network performance, network failure analysis and condition of assets
- develops appropriate maintenance and replacement programmes, based on the above analysis
- forecasts changes in customer behaviour and demand
- identifies network constraints, oversees security of supply and develops network and non-network solutions
- provides the planning interface with Transpower
- adapts planning for the impact of emerging technology
- works with developers, consultants, and major customers for new load and generation connections and network extensions

Network transformation programme team:

This team is responsible for delivering Orion's Network Transformation Roadmap. Key deliverables include:

- enhancing the sustainable connection of new technology to our distribution network
- enabling the trading of energy and capacity between customers and market participants via an open network framework
- augmenting our planning, investment and operational requirements to achieve Orion's Network Transformation Roadmap goal

Asset and spatial intelligence team:

- manages and develops our network asset register and geospatial systems to ensure our network asset data is accurate and available for the effective management of our network
- manages the content, review and dissemination of certain controlled business documents, internally and externally
- manages and develops systems and procedures to ensure accurate network reliability statistics
- provides data insights

Customer and communications – customer support team:

Our customer support team is a key point of contact for our customers. The team:

- operates 24/7 and responds to more than 1,800 calls from customers each month
- provides a point of contact for our customers seeking the help and reassurance of a real person
- provides customers with information about power outages, resolves complaints and assists with the supply of our services

Orion Development Programme:

- this programme mentors and develops our people as they progress through their focused training – see Section 10

The balance of our Future Network team is in the business support category, see 8.4.

8.3.2 Electricity Network

Our electricity network group is responsible for the daily operation of the network, delivery of AMP work programmes, and other delivery and engineering related services including business process improvement.

Engineering team:

Our engineering team provides support with engineering or technical issues and explores new opportunities to improve our network management. The team:

- focuses on ensuring a safe, reliable and effective network
- ensuring operational systems are fully scoped, tested and supported throughout their lifecycle; while also looking for opportunities to improve and optimise our operations of these systems.
- sets and maintains standards for materials and applications and maintains documentation associated with establishing, maintaining and developing our network assets
- researches and reviews new products and alternative options with a view to maximising network safety and reliability and minimising lifetime cost
- researches and evaluates latest trends in maintenance and replacement of assets
- investigates plant failure, manages protection setting data and keeps the integrity of control and protection systems at high levels
- works with our service providers when developing commissioning plans and the introduction of new standards and equipment
- analyses technical data and acts on the information to minimise the risk of loss of supply to network
- manages and maintains our key operational platforms

Network delivery team:

This team oversees programme management, works delivery, customer connections, procurement and land services, and fleet management.

The team:

- ensures the delivery of Orion's planned and unplanned works on overhead, substation and underground assets via our Primary Service Delivery Partner (PSDP), Connetics, via a dedicated arms-length Project Management Office (PMO) which plans and procures work from Connetics and other service providers
- is responsible for the establishment of the programme of works and monitoring of works through the PMO, for instance the team:
    - identifies required works and develop scopes, works specifications and designs that meet our network standards and specifications
    - ensures the work packages are suitable for delivery
    - monitors the completion of works to our budget as set out in the AMP
- responsible for procurement and works management of some functions including management of Orion's property assets, from kiosks to substations to office buildings
- manages our vegetation management programme
- undertakes other civil related and consultancy services
- ensures Orion gets value for money and the level of service we expect from the services we contract in as well as securing Orion's property and consenting interests.

Customer connections team:

The customer connections team welcomes new customers to our network. The team:

- ensures customers are connected to the electricity network in a safe and cost effective way
- manages power quality – investigates complex Orion and customer network issues. Analyses voltage disturbance and deviation problems, predominantly in industrial and commercial customer groups, while offering support and education
- manages distributed generation –reviews and approves customer connected generation. Ensures safe connections
- manages street lighting and new technology connection management. Develops and maintains Distributed Unmetered Load Data Base for major customers. Ensures accuracy and integrity of street light data on GIS
- provides low voltage management – enables safe switching operations to be carried out on Orion's network through accurate schematics and site identification
- creates and supports business processes to enable accurate updating of GIS
- manages HV labelling – enables safe switching operations to be carried out on Orion's network through site and network circuit identification
- manages Orion-owned generators to ensure safe operation. During disaster recovery, provides a specialised team to work independently from the network to enable generator power restoration to communities
- undertakes technical surveys and provides concise and simple reporting
- provides service providers and the public with safety advice and education for those working close to or around Orion assets
- reviews applications and issues, as appropriate, close approach consents to Orion-authorised service providers, third party service providers and members of the public who need to work closer than four meters from our overhead lines and support structures

8.3 System operations and network support teams continued

Network operations team:

Our network operations team includes our control centre, operations planning, field response, and network access teams.

The team:

- monitors and controls our electricity network in real time, 24/7
- provides safe network switching and fault restoration
- utilises load management to minimise peak load and maintain security
- provides load management assistance for all upper South Island EDBs
- operates high and low voltage switchgear
- provides a first response to network and customer faults
- makes safe network equipment and customer premises for emergency services
- repairs minor faults

Network access team:

- coordinates and approves access to our network, including setting standards and writing training and assessment material for both employees and authorised service providers
- trains and assesses the competency of employees and service providers to enter and work in restricted areas, and to operate our network
- maintains a database of competencies held by every person accessing and working on our network
- develops operating manuals for equipment used on our network, and support material for our network operators

Release planning team:

- coordinates and approves service provider requests to safely access the network to carry out planned work

Quality, health and safety (QHS) team:

The QHS team ensures we work safely and our community can be confident Orion contributes to a safe and healthy environment. The team:

- provides QHS governance and legislative overview
- provides continuous QHS system improvements
- provides QHS advice to Orion Group and other key stakeholders
- administers Vault, our incident and safety management system
- leads the QHS quality assurance program
- leads significant investigations – using the Incident Cause Analysis Method (ICAM)
- contributes to QHS and Orion Group training and coaching initiatives
- provides QHS analytical reporting to the Orion Group leadership team and board
- works pro-actively with industry and peak bodies to build capability
- provides a process for close approach consents for all third parties including the public and service providers operating in close proximity to Orion's electricity network

8.4 Business support teams

The business support activity area manages the support systems, processes, engages with our customers and explores future business opportunities to ensure we deliver present and future value to our customers and stakeholders. Around 25% of our people work in this area. The teams in this area are:

8.4.1 Purpose and Performance

This team leads Orion Group strategy and business plan delivery, enterprise risk management, business reporting, performance including people and capability, and sustainability.

Risk and reporting team:

This team supports, monitors and measures the business in the areas of risk management, business and board reporting and board support.

People and capability team:

This team provides strategic, tactical and operational support, including change management, and advice to the business in the people/HR space, including payroll and wellbeing.

By supporting our leaders and managers to build capability and performance we seek to achieve the best organisational results through our people.

Sustainability & risk team:

- undertakes strategic initiatives, industry collaboration and operational reporting in support of powering a low carbon economy
- implements initiatives to reduce or off-set Orion's carbon emissions
- measures and reports on our carbon emissions
- reports on the opportunities and risks associated with climate change

- directs our sustainability activity on both our network and in the wider community in support of addressing climate change opportunities and risks
- builds sustainability partnerships in the community
- assesses and reports on Orion's enterprise risks and ensures our risk mitigation strategies are in place, effective and proportional

8.4.2 Value Optimisation

This team works to ensure we deliver value for our customers and stakeholders.

Finance team:

This team is responsible for financial reporting and management. It is also responsible for treasury, tax and tax compliance, regulatory reporting, budgets, accounts payable and receivable, financial forecasting, job management, financial tax and regulatory fixed asset registers and support for financial systems. Our Privacy Officer is a member of this team.

Other value optimisation services team:

Other services include business improvement, administering Orion's internal audit programme and value, innovation and commercial and financial analysis.

8.4.3 Future Network

Regulatory and commercial team:

This team's responsibilities include pricing, government policy and regulation, billing and major customer support. This team leads:

- our advocacy, engagement and submissions to MBIE, Climate Change Commission, Ministry for the Environment and Infrastructure Commission
- our engagement with and submissions to the Commerce Commission, Electricity Authority and other industry regulators
- our network delivery pricing approach, compliance reporting and
- billing to retailers and major customers

Customer and communications team:

This team is responsible for engaging with our customers and key stakeholders, to:

- identify their needs and work with our business to ensure we can best meet these needs
- build key community relationships to enable us to deliver on our strategic community objectives
- lead internal and external communications including public relations and social media

The team also focuses on improving our customer service by:

- understanding our customers' needs
- co-creating service offerings with our customers and partners
- facilitating customer inspired conversations about future power options

8.4.4 Digital, Data & Technology

The Digital, Data & Technology team was established in FY23 to bring a strategic, Group level view on data governance and digital system evolution in support of improved decision making, system control, business outcomes and customer centricity.

Data intelligence team:

- develops a robust data governance framework to deliver a modern data platform
- builds a new data ecosystem through the application and deployment of analytical tools
- promotes data driven decision making across the organisation

Technology and platform services team:

- This team is responsible for leading the business in the selection and delivery, ongoing configuration, integration and management of our information systems. This includes standalone applications, data and computing platforms, and all supporting infrastructure
- provides tier one to tier three support for systems
- partners with vendors and expert third parties to augment in-house Orion information technology services

Project support office:

- provides governance, guidance and a consistent delivery framework to support best practice project delivery

8.4.5 Growth and Development

The growth and development team is responsible for:

- identifying, establishing and scaling business models and technologies that are new to Orion
- developing and delivering commercially viable business opportunities with a strong commercial value focus
- providing commercial energy and renewable engineering advisory services to business
- energy solutions architecture based on customer and network insights

8.4.6 Energy Futures

The energy futures team is responsible for:

- exploring future energy markets and business models
- future energy strategy
- leading exploration of innovation functions i.e. leveraging existing business models and technologies
- energy market insights and analytics
- exploring community energy solutions to support energy equity

8.4.7 Board

We have a board of five non-executive directors, with extensive governance and commercial experience.

8.4.8 Company Secretary's Office

The office of the Company Secretary is responsible for:

- our insurance programme, which is designed to manage our key risks. The fees forecast are shown in Table 8.5.1.
- governance reporting and support to the Board of directors
- managing our corporate policies and legislative compliance programme

8.5 Corporate properties

8.5.1 Asset description

Our corporate property portfolio covers our administration building at 565 Wairakei Road, Connetics' Waterloo base and rental properties throughout the Canterbury region. Our corporate properties vary in both construction and age.

- **Administration building** – our Wairakei Rd administration building was built in FY14.
- **Connetics' Waterloo base** – Connetics moved to a new, purpose-built facility in Waterloo Business Park in FY18 to provide a more operationally efficient and resilient base for its operations. Orion owns the depot with Connetics entering a long-term 'arms-length' lease.
- **Ferrymead and Rolleston satellite offices** – in FY23 we established satellite administration offices in Ferrymead and Rolleston to support flexible working options for our people living near those locations, and reduce our people's carbon emissions associated with commuting to work. These offices are leased.
- **Rental properties** – we own nine rental properties four of which are residential properties adjacent to zone substations. Some of these were acquired as part of a package when substation land was purchased. Others have been strategically purchased to allow the substation to expand if necessary. We receive income from these properties, provided they are tenanted, and this rental income is in line with the rental market in the Christchurch area.

As part of our Pandemic Response Plan, we established a permanent emergency operational centre for our Controllers and Customer Support team at our Papanui zone substation.

We are a lifelines utility under the Civil Defence Emergency Management Act 2002, providing essential services to the community. This means we are required to be operational after a significant event. Our administration building was built to Importance Level 4 (IL4). This means that the building is designed to remain operational following a 1 in 500 year seismic event. The building is also equipped with a standby generator, with 500 litre diesel tank, to provide back-up power.

As part of our Pandemic Response Plan, we established a permanent emergency operational centre for our Controllers and Customer Support team at our Papanui zone substation.

Our property assets must meet the following criteria:

- they must be fit for purpose and maintained in a reasonable condition so the occupier can fully utilise the premises
- they shall comply with all building, health and safety standards that may apply
- they must be visually acceptable

8.5.2 Maintenance plan

We have no assigned 'end of life' for our corporate properties. Our property asset management programme ensures our corporate property is managed in a manner that is consistent with Orion's corporate obligations to deliver an effective and efficient service.

We carry out regular inspections of our buildings to ensure they remain in good condition and any need for maintenance is identified. Several databases are used to assist us with the management process such as our asset register and our works management system. The risks that our corporate buildings are exposed to are listed below, in no particular order of importance:

- seismic damage
- liquefaction and subsidence
- defective drainage and guttering
- roof leaks
- vegetation/tree roots
- vandalism – repairs carried out as soon as reported
- graffiti
- rust and rot
- extreme weather conditions
- fire

8.5 Corporate properties continued

We have observed a significant increase in network property vandalism and graffiti this year, and have increased our network security arrangements and facilitated reporting of it by the public via Snap, Send, Solve. All damage to the network or premises is repaired as soon as soon as we become aware of it, and graffiti is generally painted over within 24 hours.

Minor repairs are undertaken as they are identified in the inspection process. Major repair and maintenance work is scheduled, budgeted for and undertaken on an annual basis. Vandalism and graffiti is fixed as soon as we are notified.

We have maintenance contracts in place with several service providers to ensure that all aspects of our property and land maintenance are covered.

8.5.3 Replacement plan

We have no replacement plan for our corporate properties. These assets are maintained to ensure they provide the required levels of performance.

8.6 Network information systems

Orion has a complex range of sophisticated information systems that together support the operation of our network. Here we outline what those systems do and how they interact with each other.

8.6.1 Geographic asset information system

Our Geospatial Information System (GIS) records the location of our network assets and their electrical connectivity. It is one of our integrated asset management systems.

Full access to the GIS is continuously available to the Orion team through locally connected and remote viewing tools.

Tailored views of GIS data are also available to authorised third parties via a secure web client. Information stored in our GIS includes:

- land-base
- aerial photography
- detailed plant locations for both cable and overhead systems
- a model of our electricity network from the Transpower GXPs to the customer connection
- conductor size and age

Our asset and spatial intelligence team updates and maintains the GIS data. Data integrity checks between our asset register and the GIS are automatically run every week. Systems are in place to facilitate and manage GIS business development in-house.

Our GIS platform is mature and approaching end of life and we will select and deploy a replacement solution as part of the programme of work associated with the uplift of our asset management capability.

8.6.2 Asset database

Our asset database is our central repository for details of the non-spatial network assets. Asset management data informs the Condition Based Risk Management (CBRM) model we use to assess asset health and risks. Schedules extracted from this database are used for preventative maintenance contracts and network valuation purposes.

Information we hold includes:

- substation land (title/tenure etc.)
- transformers
- switchgear and ancillary equipment
- test/inspection results for site earths, poles and underground distribution assets
- transformer maximum demand readings
- cables and pilot/communication cable lengths, joint and termination details. This is linked to our GIS by a unique cable reference number
- protection relays
- substation inspection/maintenance rounds
- poles and attached circuits
- valuation schedule codes and Modern Equivalent Asset (MEA) class
- field SCADA and communication system
- links to documentation and photographs

See Appendix C for more specific details of the information held on each asset group.

Our GIS platform is mature and approaching end of life and we will select and deploy a replacement solution as part of the programme of work associated with the uplift of our asset management capability.

8.6.3 Works Management system

All works activities are managed using an in-house application. There is integration with our financial management system that allows works orders to be raised directly in Works Management.

Information held in Works Management includes:

- service provider/tendering details
- contract specifications and drawings
- management of customer connection requests
- auditing outcomes
- contract management documentation
- financial tracking
- job as-built documentation

Our Works Management system is bespoke and there is little scope for future development, due to the aging technology on which it is built and the limitations of its architecture. It is an end of life system. The selection/deployment of a replacement solution will form part of the programme of work associated with the uplift of our asset management capability.

8.6.4 Document management

We manage most of our key documents in Microsoft SharePoint.

Our engineering drawings and standard documents are controlled using a custom-built system. This system is used to process the release of CAD drawings to outsourced service providers and return them as "as-built" drawings at the completion of works contracts. Standards and policies maintained in-house are also controlled using this system. Standard drawings and documents are then posted directly on our 'restricted' website and the relevant service providers/designers are advised via an automated email process.

8.6.5 Connections Register

Our Connections Register, which links to the Industry Registry, holds details of all Installation Control Points (ICP) on our electrical network. There is an interface with our GIS systems that enables accurate derivation of GXP information by ICP and the association of ICP with an interruption. Interruptions are routinely traced within the Advanced Distribution Management System (ADMS) for the high voltage network and the GIS for the low voltage network using the in-built connectivity model. Accurate information about the number of customers and interruption duration are recorded and posted in near real-time to Orion's external website.

8.6.6 Financial Management Information System (FMIS)

Our FMIS (Microsoft NAV) delivers our core accounting functions. It includes the general ledger, debtors, creditors, job costing, fixed assets and tax registers. Detailed network asset information is not held in the FMIS.

There is an interface between the Works Management system and the financial system to link project activities to jobs.

8.6.7 Cyber security management

We have a number of protection systems and processes in place to address the growing threat of cyber security breaches. See Section 3.7.4.

8.6.8 Advanced Distribution Management System (ADMS)

We operate an integrated ADMS from GE Digital that includes the following modules:

Network monitoring system (SCADA)
The electricity distribution system is monitored and controlled in real time by the SCADA system. SCADA is installed at all zone substations and an increasing number of switching equipment. We are also progressively installing SCADA at network substations throughout the urban area as old switchgear is replaced.

Network Management System (NMS)
The NMS is a real-time software model of our high voltage distribution network that sits above the SCADA system. It allows interaction in real time with indication and control devices to provide better information on network configuration. This gives us the ability to decide on how to respond to network outages, especially major events such as storms, and manage planned maintenance outages to minimise the impact on customers. The system also allows us to automate some functions and improve response times in network emergencies.

Outage Management System (OMS)
The OMS is the third component (along with the SCADA and NMS functions) of a comprehensive "Smart" Distribution Management System that drives much of our operational activity. Outages are inferred from SCADA 'trippings' or from customer call patterns and are tracked through their lifecycle. Key performance statistics are automatically calculated and an audit trail of HV switching activity is logged. Integrated into the NMS and OMS is a mobile extension which delivers

We have a number of protection systems and processes in place to address the growing threat of cyber security breaches.

switching instructions to field operators in real time and returns the actions they have taken. It also delivers fault jobs to field workers and tracks the progress of the job as it is worked on. Jobs requiring further work by an emergency service provider are dispatched to the service providers' administration centre. Service providers enter completion information directly into a web-based application, and the job details automatically flow through into the works database.

Mobile operating platform (Peek)
Field Operators interact with our Control Systems in real time through an in-house developed mobile application called Peek. An Operator receives operating instructions in the field on a hand-held device and, as each operating step is undertaken, updates the system. The completed operating steps are available for the Control Room to see in real time, and the network diagram is automatically updated accordingly.

Distribution Power Flow Analysis (DPF)
DPF is a decision support tool for our Network Controllers. It performs network power analysis studies that estimate the state of the network and provides power analysis data to Controllers. DPF studies can run as simulations and what if scenarios include both planned and unplanned work operations.

Online release request system
We are currently developing an online release request system to manage our contractor requests to work on the network. This system is expected to be operational in 2023 and replaces a largely manual, paper-based system for planned outages.

8.6.9 Load Management

A high-availability Load Management system is used to perform load shedding to reduce the magnitude of our peak load and to respond to Transpower constraints. We also run an "umbrella" Load Management system that co-ordinates the load management systems of each of the seven distributors in Transpower's Upper South Island region. This co-operative venture provides a number of significant benefits both to Transpower and to each of the participating distributors.

8.6.10 Network analytics

A database of well over 100 million half-hour loading values is available for trend analysis at a wide range of monitoring points in our network. The database also includes Transpower grid injection point load history and major customer load history. Several tens of thousands of new data point observations are being added daily. Half hour network feeder loading data is retrieved from the SCADA historical storage system. This data is analysed to derive and maintain maximum demands for all feeders monitored by the SCADA system. Loading data is also archived for future analysis.

8.6.11 Data warehouse and business intelligence

Over the next 12 months, we will implement a major shift in our capability regarding the governance, curation and delivery of data for business decision making.

Our new data platform will create opportunities through new analytical tools, greater storage and computing power and access to a community of experts.

We will implement a modern data platform that incorporates and builds on our current data repositories. Our new data platform will create opportunities through new analytical tools, greater storage and computing power and access to a community of experts.

Existing data from financial, asset management and control systems will be maintained to meet increasing demand for more sophisticated business reporting, analytics and dashboards. New data will be made available and business insights gained through analytics and reporting.

8.6.12 Interruption statistics

We automatically post outage information from the ADMS OMS into a regulatory reporting database. After checking, the data is summarised along with cause and location in an interruption register. Reports from this register provide all relevant statistical information to calculate our network reliability statistics (such as SAIDI and SAIFI) and analyse individual feeder and asset performance.

8.6.13 Demolition tracking

Demolition jobs are dispatched to the field and demolition details returned electronically.

8.6.14 Condition Based Risk Management (CBRM)

CBRM is a spreadsheet-based modelling program that uses asset information, engineering knowledge and experience to define, justify and target asset renewals. For more information on CBRM see Section 5.5.2.1.

8.6.15 Health and safety event management

Incidents are recorded, managed and reported in our safety management system. This enables incidents and injuries to be captured using a desktop client or in the field using a phone-based application. This system also manages non-staff related incidents, e.g. incidents affecting our network and customer complaints.

8.6.16 Delivery billing system

We have contracted NZX Energy, a leading data services and market place support company, to provide our delivery billing system. The system receives connection and loading information, calculates delivery charges and produces our monthly invoices to electricity retailers and directly contracted major customers.

8.6.17 Power system modelling software

An integral part of planning for existing and future power system alterations is the ability to analyse and simulate impact off-line using computer power-flow simulation.

We use a power-flow simulation software package called PSS/Sincal and can model our network from the Transpower connection points down to the customer LV terminals if required. An automated interface developed in-house is used to enable power-flow models to be systematically created for PSS/Sincal. These models are created by utilising spatial data from our GIS, and linkages to conductor information in our as-laid cables database and customer information in our connection database records.

8.6.18 Orion website

Our website is logically divided into two distinct areas. One focuses on the delivery of information to our customers and the other on interactions with third parties.

The customer facing portion of the web site provides the following information:

- Customer outage reporting - details of planned, current and past outages on our web site are populated automatically by extracts from the ADMS Outage Management System. This provides accurate real-time reporting of customer numbers affected by an outage. Outages can be viewed as a list or on a map. The site also has the facility to provide progress updates which are added manually by our Customer Support team
- Load management - we provide near real-time network loadings, peak pricing periods and hot water control
- Electricity pricing
- Company publications, regulatory disclosures and media releases
- Public safety and tree trimming information

The interactive section of our website is a services portal that manages third party access to a range of services.

Services include:

- connections-related service requests for new and modified network connections.
- annual work plan
- standard drawings, design standards, operating standards, specifications
- network location map requests
- close approach consents
- new and modified connection requests
- livening requests for action by livening agents

8.6.19 Customer Relationship Management

We are continuing to develop our Customer Relationship Management (CRM) system that will be a cornerstone for the digitisation of business processes and delivery of services to our customers. The CRM is being built around Microsoft's Dynamics platform and will incorporate several functions currently managed through other systems. It will establish a "single source of truth" for customer related information and allow real time interactions with other business systems.

The CRM has automated our close approach, high load and standover consents application processes.

An improved "opt in" outage notification service for customers was delivered in mid FY23 and we will be managing our new connections process in CRM in early FY24.

8.6.20 Low Voltage Data Model

As part of a wider strategic initiative associated with the future operation of our low voltage network we are developing a model for the collection, storage and consumption of data on the status and performance of LV assets. A prototype is currently under development.

8.6.21 Maintenance plan

All our systems are supported directly by our technology and platform services team with vendor agreements for third tier support where appropriate. License costs provide a degree of application support but are largely a prepayment for future upgrades.

Although licenses guarantee access to future versions of software they do not pay for the labour associated with their implementation. In our experience, significant support is required for the vendor to accomplish an upgrade and these costs are reflected as capital projects in our budgets.

We are continuing to develop our Customer Relationship Management (CRM) system that will be a cornerstone for the digitisation of business processes and delivery of services to our customers.

8.6.22 Replacement plan

As outlined in Section 8.2, we are focused on upgrading and developing new systems and processes to gear up for the future. Our replacement plan for Orion's network information systems over this 10 year AMP period includes implementation of an Integrated Asset Management (IAM) platform which will digitise and automate end to end asset lifecycle management including:

- asset investment decision support
- enterprise asset management
- works order and delivery management
- geospatial systems and asset database refresh
- field service orchestration and automation

This is a considerable program of work involving significant investment in people, process redesign, technology, automation and integration to support asset management from optioneering to disposal. The IAM coupled with improvement in our asset information process for collecting, storing, maintaining and analysing our network asset data, will be a key enabler within Orion to support:

- the processes for network planning, network transformation, lifecycle management, works delivery, network operations, and associated reporting requirements
- analysis and insight discovery to support continued process improvement, asset management strategy review and asset information audits
- improved operational efficiency and informed decision making

We are focused on upgrading and developing new systems and processes to gear up for the future.

Additionally, over this AMP period a number of digital and data applications and services will undergo lifecycle upgrades, enhancements and improvements. These include:

- extension of the centralised data intelligence and analytics platform to provide deeper insights and observations on the activity, capacity and flows on our network to enable and assist forecasting
- further expansion and automation of the customer connections processes onto the CRM platform, to improve operational efficiency and customer service to support growth in this vital area of network service
- upgrades to our financial platform to automate and link processes to improve operational efficiency
- upgrades our corporate information systems to improve operational efficiency and productivity
- upgrades to the online information channels that support customers and service providers, including the internet site, to increase the timely availability and ease of access to information they need

For the capex and opex expenditure to transform our data and information management capability, see Section 9.

8.7 Asset data integrity

Most of our primary asset information is held in our asset database, GIS system and cable database. We hold information about our network equipment from GXP connections down to individual LV poles with a high level of accuracy.

Due to improved asset inspection programmes, regulatory compliance and better risk identification and management, asset information accuracy has improved. This has ensured that we can locate, identify and confirm ownership of assets through our records.

Although there will inevitably be some minor errors and improved information will always be required, we believe our information for most of our network is accurate.

We have found some instances of incorrect conductor types listed in our asset database. To address this, we will start collecting better overhead conductor information to enable proactive and efficient prioritisation of future conductor maintenance and renewal programmes. Some information for older assets installed more than 25 years ago has been estimated based on best available data. Examples of this include:

- the conductor age for some lines older than circa 1990
- timber poles that went into service prior to the use of identification discs
- older 11kV air break switches and cut-out fuses

8.8 Corporate information systems

Our corporate business information systems and productivity software support processes that run across Orion. They include financial systems, employee management systems, for example human resources, payroll, health and safety and personal productivity software such as desktop applications, email, web and document management.

Our supporting computing infrastructure hosts, connects and provides access to our information systems. In most cases we manage our computing infrastructure in house because of the critical nature of some of our information systems and the need for them to be continuously connected in real time to equipment on the electricity network.

We have traditionally delivered services using a combination of on-premise and Software-as-a-Service. By the end of FY24 we will have moved most of our productivity software (Outlook, SharePoint, Office etc) to the Microsoft 365 environment in line with our cloud strategy.

The infrastructure supporting our information systems includes:

- **HR/payroll** – as a cloud-based application the performance and availability of this system is subject to a service level agreement.
- **Email system** – the capacity and performance of our Email system is adequate for the period of this plan if there are no major changes required. Our email system is a mature and well established application. It will be integrated with document management as part of the current implementation.
- **Workplace collaboration systems** – we use Microsoft Teams and Workplace to support new ways of working and sharing information across our teams.
- **Desktop/laptop clients and operating systems** – our choice of operating system and desktop software capacity/performance are adequate for the duration of this plan. The desktop operating system is current and subject to regular security and performance updates from Microsoft. Changes may be forced on us in the future as new equipment becomes unsupported on the current version.
- **Replicated computer room** – we operate two Transportable Data Centres linked by diverse fibre networks which are both performing to expectations.
- **VM and SAN** – our VMware Virtual Server and Storage Area Network infrastructure is managed through a life cycle and regularly upgraded before performance issues arise or warranties expire. Capacity and performance are adequate for the duration of this plan.
- **Physical servers** – we still occasionally use individual physical service for specific applications. As with all our infrastructure we manage these servers through a lifecycle. The health of these servers are monitored and we typically replace servers of this type in three to five years.
- **Desktops, laptops, tablets** – we typically upgrade our desktops and laptops on a three-yearly cycle. We expect that the capacity and performance of this equipment will not be adequate for the duration of this plan.

8.8.1.1 Maintenance plan

All corporate systems are supported directly by our Information Solutions group with vendor agreements for third tier support where appropriate.

We employ a strict change management regime. Software releases, and patches are applied to systems as necessary and only after testing.

8.8.1.2 Replacement plan

We employ a rigorous change management approach to all software and hardware systems. Major changes to all corporate business information systems will follow a project proposal, business case approval, business requirements.

Where appropriate project costs are capitalised, including around $1.2m of labour per annum.

We employ a rigorous change management approach to all software and hardware systems.

8.9 Vehicles

8.9.1 Asset description

We own 97 vehicles to enable us to operate and maintain the electricity network, engage with the community and respond to any events. Our goal is to ensure we have the right vehicle in the right place at the right time with an appropriately trained driver. Around 55% of our passenger fleet has electric drive capability.

The performance criteria vary for each vehicle class. All are operated within their manufacturer specified parameters. Our vehicles are relatively new and regularly maintained. As a result they are in good condition.

8.9.2 Maintenance plan

All vehicles within their warranty period are serviced according to the manufacturers' recommended service schedule by the manufacturers' agent. For vehicles outside of their warranty the servicing requirements are also maintained in accordance with the manufacturers' specifications by a contracted service agent.

Around 55% of our passenger fleet has electric drive capability.

8.9.3 Replacement plan

Our fleet replacement plan aims to replace vehicles on a like-for-like basis, where applicable, when the vehicle reaches its designated age or distance covered. If the fundamental needs of the driver change, the change will be reflected in the type of vehicle purchased for replacement. Where possible we purchase vehicles that better fit our needs and where there is a demonstrable gain in safety, efficiency, reliability and value for money. In keeping with our strategic focus on sustainability and commitment to reducing our carbon footprint, where they are fit for purpose we will seek out electric vehicle options.

8.9.3.1 Vehicle acquisition plan

The aim is to have the right vehicle and driver in the right place at the right time. This is a critical aspect of operating our network in a safe, reliable and efficient manner. The key drivers in our vehicle acquisition plan are:

- fitness for purpose
- safety
- reliability
- sustainability and fuel economy
- value for money/lowest economic cost over the life of the vehicle (including disposal value)
- diversity within the fleet – spreading the risk

8.9.3.2 Disposal plan

Our vehicles are typically disposed of via auction. In this way we achieve a market value for the vehicle and also incur the minimum disposal cost in terms of time and money.

Table 8.8.1 Vehicle quantities and type

Description	Quantity	Lifecycle
Generator truck	4	20 years
Network operator utility	22	5 years or 200,000 km
Battery Electric Vehicle (BEV)	17	6 years
Plug-in Hybrid EV (PHEV)	22	6 years
Other	32	4 years on average (earlier for high km's)
Total	**97**	

9

Financial forecasting

$503m

Network operating expenditure

$735m

Non-network operating expenditure

$2,984m

Capital expenditure

Photo: Shot from Plantation Road, Hororata during a nor'wester at sunset; photo taken by Orion Network Operator, Martin Van Beyere.

Contents

9.1 Network expenditure forecasts

Our forecasts are based on our network opex and capex programmes and projects as detailed in Sections 6 and 7. These forecasts are based on the best information available at the time of publishing. The forecasts in this section are all in real dollar terms.

9.1.1 Opex – network

Table 9.1.1 Opex – network – $000

Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Subtransmission overhead lines	662	870	2,137	2,084	2,042	2,044	2,042	2,085	2,072	2,085	**18,123**
11kV overhead lines	8,035	10,293	15,160	15,723	20,576	23,543	25,505	27,508	26,453	28,457	**201,253**
400V overhead lines	3,176	3,377	4,888	6,455	6,955	6,455	6,955	7,955	9,455	8,955	**64,626**
Storms	245	245	245	500	500	500	500	1,000	1,000	1,000	**5,735**
Earths	410	375	415	450	440	415	415	415	415	415	**4,165**
Subtransmission underground	415	155	95	105	115	105	95	105	115	105	**1,410**
11kV underground cables	1,800	1,800	2,410	2,410	1,910	1,910	1,910	1,910	1,910	1,910	**19,880**
400V underground cables	2,665	2,665	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	**28,930**
Communication cables	100	100	100	100	100	100	100	100	100	100	**1,000**
Asset information / management	5	5	5	5	5	5	5	5	5	5	**50**
Monitoring and PQ	120	21	29	5	13	29	21	29	99	21	**387**
Protection	615	615	625	625	630	630	635	635	640	640	**6,290**
Communication systems	669	649	580	580	580	580	580	580	580	580	**5,958**
Control systems	550	663	730	870	810	835	960	1053	1038	1120	**8,629**
Load management	425	435	445	445	445	445	445	445	445	445	**4,420**
Switchgear	1,450	1,505	1,755	1,785	1,910	1,890	1,965	1,975	1,860	1,810	**17,905**
Transformers	1,033	1,320	1,633	1,540	1,240	940	960	940	940	950	**11,496**
Substations	1,122	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	**11,274**
Generators	45	45	45	45	45	45	45	45	45	45	**450**
Buildings and enclosures	1,109	1,135	1,175	1,155	1,175	1,155	1,175	1,155	1,175	1,165	**11,574**
Grounds	495	495	515	515	515	515	515	515	515	515	**5,110**
Emergency works fixed costs	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	**26,400**
Project management resource (PMO)	1,000	1,001	1,157	1,259	1,397	1,461	1,542	1,651	1,663	1,707	**13,838**
Network Transformation	-	275	5,225	5,555	3,740	3,905	3,905	3,905	3,905	3,905	**34,320**
Total	**28,786**	**31,812**	**46,087**	**48,929**	**51,861**	**54,225**	**56,993**	**60,729**	**61,148**	**62,653**	503,223
Total from 1 April 2022 AMP	**29,813**	**29,958**	**40,061**	**40,915**	**40,785**	**40,673**	**40,705**	**41,218**	**40,868**	n/a	n/a

9.1 Network expenditure forecasts continued

9.1.2 Opex – network (Commerce Commission's categories)

Table 9.1.2 Opex – network (Commerce Commission's categories) – $000

Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
System interruptions and emergencies	9,634	9,654	9,671	9,940	9,940	9,940	9,940	10,455	10,455	10,455	**100,084**
Vegetation Management	4,455	4,648	6,278	7,725	10,300	11,330	12,360	13,390	13,390	13,390	**97,266**
Routine and corrective maintenance & inspection	14,316	15,384	24,999	26,883	28,649	30,292	32,030	34,221	34,640	36,145	**277,559**
Asset replacement & renewal	381	2,126	5,139	4,381	2,972	2,663	2,663	2,663	2,663	2,663	**28,314**
Total	**28,786**	**31,812**	**46,087**	**48,929**	**51,861**	**54,225**	**56,993**	**60,729**	**61,148**	**62,653**	**503,223**
Totals from 1 April 2022 AMP	**29,813**	**29,958**	**40,061**	**40,914**	**40,784**	**40,673**	**40,705**	**41,219**	**40,868**	**n/a**	**n/a**

9.1.3 Opex contributions revenue

Table 9.1.3 Opex contributions revenue – $000

Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
USI load management	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	**(1,000)**
Network recoveries	(1,000)	(999)	(998)	(997)	(996)	(995)	(994)	(993)	(992)	(991)	**(9,955)**
Total	**(1,100)**	**(1,099)**	**(1,098)**	**(1,097)**	**(1,096)**	**(1,095)**	**(1,094)**	**(1,093)**	**(1,092)**	**(1,091)**	**(10,955)**
Totals from 1 April 2022 AMP	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**n/a**	**n/a**

9.1.4 Capex summary

Table 9.1.4 Capex summary – $000

Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Customer connections/ network extensions	25,000	22,000	22,660	23,340	24,040	24,761	25,504	26,269	27,057	27,869	**248,500**
Asset relocations	11,880	9,560	8,148	7,948	10,744	6,964	9,207	9,207	9,207	9,207	**92,072**
HV major projects	30,867	33,194	61,062	71,016	61,755	74,418	91,532	124,855	141,282	165,559	**855,540**
HV minor projects	12,422	4,740	11,837	36,852	44,639	64,505	76,419	80,097	87,962	91,809	**511,282**
LV projects	2,297	3,694	8,910	12,998	17,092	25,045	29,046	27,332	32,222	34,406	**193,042**
Replacement	41,081	45,527	59,526	79,532	85,006	91,929	88,663	93,488	98,096	95,947	**778,795**
Network Transformation	-	275	6,545	4,565	3,080	2,695	2,695	2,695	2,695	2,695	**27,940**
Data and Digitisation	200	200	400	500	500	500	500	500	500	500	**4,300**
Capitalised internal labour	9,297	9,002	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	**90,299**
Project management resource (PMO)	2,640	2,640	4,240	6,011	6,255	7,678	8,571	9,774	10,787	11,632	**70,228**
Total	**135,684**	**130,832**	**192,328**	**251,762**	**262,111**	**307,495**	**341,137**	**383,217**	**418,808**	**448,624**	**2,871,998**
Totals from 1 April 2022 AMP	**100,023**	**83,680**	**104,186**	**103,191**	**98,121**	**96,811**	**98,367**	**98,557**	**98,068**	**n/a**	**n/a**

9.1.5 Capital contributions revenue

Table 9.1.5 Capital contributions revenue – $000

Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Customer connections/ network extensions	(1,825)	(3,300)	(3,399)	(3,501)	(3,606)	(3,714)	(3,826)	(3,940)	(4,059)	(4,180)	**(35,350)**
Asset relocations	(10,584)	(8,614)	(7,286)	(6,993)	(9,109)	(6,036)	(8,104)	(8,104)	(8,104)	(8,104)	**(81,038)**
Network development	(5,160)	(11,416)	(21,581)	(18,388)	(12,836)	(21,131)	(29,754)	(43,513)	(57,235)	(73,601)	**(294,615)**
Total	**(17,569)**	**(23,330)**	**(32,266)**	**(28,882)**	**(25,551)**	**(30,881)**	**(41,684)**	**(55,557)**	**(69,398)**	**(85,885)**	**(411,003)**
Totals from 1 April 2022 AMP	**(10,061)**	**(3,265)**	**(2,155)**	**(2,155)**	**(2,502)**	**(2,238)**	**(2,238)**	**(2,238)**	**(2,214)**	**n/a**	**n/a**

9.1.6 Capex – customer connections / network extension

Table 9.1.6 Capex – customer connections / network extension – $000

Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
General connections	9,000	8,500	8,800	9,000	9,040	9,311	9,590	9,878	10,174	10,480	**93,773**
Large connections	4,000	3,500	3,500	4,000	4,000	4,120	4,244	4,371	4,502	4,637	**40,874**
Subdivisions	4,500	4,000	4,360	4,340	4,000	4,120	4,244	4,371	4,502	4,637	**43,074**
Switchgear purchases	2,500	2,000	2,000	2,000	2,500	2,575	2,652	2,732	2,814	2,898	**24,671**
Transformer purchases	5,000	4,000	4,000	4,000	4,500	4,635	4,774	4,917	5,065	5,217	**46,108**
Total	**25,000**	**22,000**	**22,660**	**23,340**	**24,040**	**24,761**	**25,504**	**26,269**	**27,057**	**27,869**	**248,500**
Totals from 1 April 2022 AMP	**15,926**	**15,926**	**15,926**	**14,572**	**16,361**	**17,331**	**18,606**	**18,926**	**18,918**	**n/a**	**n/a**

9.1.7 Asset relocations / conversions

On occasion we are required to relocate some of our assets or convert sections of our overhead lines to underground cables at the request of road corridor authorities, councils or developers. We negotiate with the third parties to share costs and agree on timeframes. Our forecast for asset relocations / conversions are shown in Table 9.1.7

Table 9.1.7 Asset relocation / conversion capex – $000

Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
FY24 AMP	11,880	9,560	8,148	7,948	10,744	6,964	9,207	9,207	9,207	9,207	**92,072**
Contributions	(10,584)	(8,614)	(7,286)	(6,993)	(9,109)	(6,036)	(8,104)	(8,104)	(8,104)	(8,104)	**(81,038)**
Total	**1,296**	**946**	**862**	**955**	**1,635**	**928**	**1,104**	**1,103**	**1,103**	**1,103**	**11,034**
Totals from 1 April 2022 AMP	**2,079**	**655**	**518**	**518**	**964**	**1,060**	**1,273**	**1,326**	**1,319**	**n/a**	**n/a**

9.1 Network expenditure forecasts continued

9.1.8 Capex – replacement

Table 9.1.8 Capex – replacement – $000

Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Subtransmission overhead	1,129	1,208	1,029	4,294	4,794	5,294	5,794	5,294	6,294	6,294	**41,424**
11kV overhead lines	12,420	16,320	21,830	32,260	33,210	38,010	35,970	37,670	37,670	38,670	**304,030**
400V overhead lines	291	591	870	3,791	4,041	13,291	12,541	17,791	22,041	21,291	**96,539**
11kV underground cables	200	200	800	800	800	800	800	800	800	800	**6,800**
400V underground cables	7,998	8,098	5,845	6,485	9,385	6,635	5,195	5,195	5,195	5,195	**65,226**
Communication cables	80	80	80	80	80	80	80	80	80	80	**800**
Monitoring	98	98	98	98	24	24	24	24	24	24	**536**
Protection	1,891	914	2,273	2,067	2,106	1,995	2,090	2,090	3,200	2,190	**20,816**
Communication systems	1,207	1,073	745	816	1,565	1,999	2,117	1,840	1,940	1,913	**15,215**
Control systems	1,564	1,653	2,182	588	1,388	788	1,388	918	1,412	788	**12,669**
Load management	1,606	956	1,476	1,516	1,264	1,230	886	1,012	1,012	760	**11,718**
Switchgear	9,082	7,625	15,927	21,413	21,135	16,569	17,364	16,360	14,014	13,528	**153,017**
Transformers	1,620	4,940	4,716	2,275	3,075	3,075	2,275	2,275	2,275	2,275	**28,801**
Substations	868	694	658	2,052	1,842	1,842	1,842	1,842	1,842	1,842	**15,324**
Generators	22	22	22	22	22	22	22	22	22	22	**220**
Buildings and enclosures	675	1,005	925	925	225	225	225	225	225	225	**4,880**
Grounds	330	50	50	50	50	50	50	50	50	50	**780**
Total	**41,081**	**45,527**	**59,526**	**79,532**	**85,006**	**91,929**	**88,663**	**93,488**	**98,096**	**95,947**	**778,795**
Totals from 1 April 2022 AMP	**36,688**	**35,717**	**46,130**	**50,576**	**46,227**	**46,084**	**48,293**	**46,565**	**47,519**	**n/a**	**n/a**

9.1.9 Capex – replacement (Commerce Commission's categories)

Table 9.1.9 Capex – replacement (Commerce Commission's categories) – $000

Category	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Subtransmission	1,159	1,238	1,029	4,294	4,794	5,294	5,794	5,294	6,294	6,294	**41,484**
Zone Substation	5,728	7,394	12,662	13,048	11,348	6,148	7,469	6,591	5,355	3,968	**79,711**
Distribution & LV Lines	12,030	16,230	21,499	34,850	36,420	50,470	47,700	54,650	58,900	59,150	**391,899**
Distribution & LV Cables	758	858	1,995	1,995	3,995	4,995	5,995	5,995	5,995	5,995	**38,576**
Distribution substations & transformers	2,359	2,062	2,442	4,241	4,831	4,831	4,031	4,031	4,031	4,031	**36,890**
Distribution Switchgear	6,950	6,054	10,512	13,026	13,865	13,884	13,559	13,559	13,559	13,198	**118,166**
Other network assets	4,056	3,270	3,558	1,609	3,239	3,543	3,791	3,044	3,638	2,987	**32,735**
Quality of Supply	60	60	258	258	103	103	103	103	103	103	**1,254**
Other reliability safety and environment	7,981	8,361	5,571	6,211	6,411	2,661	221	221	221	221	**38,080**
Total	**41,081**	**45,527**	**59,526**	**79,532**	**85,006**	**91,929**	**88,663**	**93,488**	**98,906**	**95,947**	**778,795**
Totals from 1 April 2022 AMP	**43,732**	**36,688**	**35,717**	**46,130**	**50,576**	**46,227**	**46,084**	**48,293**	**46,565**	**n/a**	**n/a**

9.2 Non-network expenditure forecasts

9.2.1 Opex non-network

This section describes our forecast opex to plan, operate and administer our network operations. It does not include opex on our network assets, consistent with the Commission's required expenditure breakdowns and definitions.

Notes to expenditure:

- $ are in FY24 dollar terms
- our most significant operational expenditure in these teams is remuneration for our employees
- it also does not include pass-through costs, such as local authority rates and industry levies, depreciation and transmission purchases

We have allocated a network innovation investigation budget to explore alternative models of supporting our network and system operations to drive future distribution network models.

Table 9.2.1 System operations and network support – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Infrastructure management	1,306	1,306	1,366	1,415	1,570	1,753	1,952	2,166	2,397	2,637	**17,868**
Network strategy and transformation	1,562	3,136	4,830	5,200	5,530	6,602	2,565	1,793	1,793	1,793	**34,804**
Network management	5,955	5,955	6,249	6,474	7,182	8,013	8,921	9,896	10,951	12,044	**81,640**
Network operations	8,166	8,166	8,655	8,964	9,934	11,074	12,320	13,657	15,104	16,603	**112,643**
Customer Support	777	777	812	842	934	1,042	1,161	1,288	1,426	1,568	**10,627**
Engineering	3,952	3,952	4,225	4,374	4,844	5,395	5,998	6,645	7,345	8,071	**54,801**
Works delivery	1,495	1,495	1,559	1,616	1,793	2,002	2,230	2,475	2,740	3,014	**20,419**
Customer connections	2,845	2,845	2,968	3,076	3,414	3,811	4,245	4,711	5,215	5,737	**38,867**
Procurement and property services	1,340	1,340	1,397	1,448	1,607	1,794	1,998	2,217	2,455	2,701	**18,297**
Quality, health, safety and environment	1,089	1,089	1,267	1,308	1,438	1,590	1,756	1,934	2,127	2,327	**15,925**
Asset storage	1,156	1,156	1,210	1,253	1,391	1,552	1,728	1,918	2,123	2,335	**15,822**
Less capitalised internal labour	(8,960)	(8,960)	(9,074)	(9,413)	(10,477)	(11,728)	(13,094)	(14,561)	(16,149)	(17,793)	**(120,208)**
Total	**20,683**	**22,258**	**25,464**	**26,557**	**29,160**	**32,900**	**31,780**	**34,139**	**37,527**	**41,037**	**301,505**
Totals from 1 April 2022 AMP	**19,245**	**19,847**	**18,996**	**19,122**	**19,329**	**19,361**	**19,289**	**19,280**	**19,310**	**n/a**	**n/a**

9.2.2 Board of directors' fees and expenses

Table 9.2.2 Board of directors' fees and expenses – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Board of directors' fees and expenses	454	454	454	454	454	454	454	454	454	454	**4,540**
Total	**454**	**454**	**454**	**454**	**454**	**454**	**454**	**454**	**454**	**454**	**4,540**
Totals from 1 April 2022 AMP	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**n/a**	**n/a**

9.2 Network expenditure forecasts continued

9.2.3 Business support

Table 9.2.3 Business support – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Future network	1,394	1,394	1,461	1,517	1,692	1,883	2,107	2,349	2,610	2,880	**19,287**
People and capability	2,209	2,209	2,581	2,670	2,947	3,281	3,637	4,020	4,433	4,862	**32,849**
Leadership	8,686	8,686	9,515	9,863	10,954	12,236	13,637	15,141	16,768	18,454	**123,940**
Finance	1,943	1,943	1,982	1,975	2,304	2,505	2,912	3,155	3,604	3,916	**26,239**
Technology and platform services	8,297	8,297	10,415	10,737	11,901	13,193	14,863	16,337	17,944	19,568	**131,552**
Commercial	1,865	1,865	2,085	2,120	2,354	2,629	2,930	3,253	3,602	3,964	**26,667**
Customer and stakeholder	2,295	2,295	2,406	2,498	2,786	3,125	3,495	3,892	4,322	4,767	**31,881**
Insurance	2,914	2,914	3,577	3,987	4,669	5,440	6,278	7,181	8,155	9,185	**54,300**
Corporate property	1,003	1,003	1,077	1,131	1,266	1,424	1,591	1,772	1,968	2,172	**14,407**
Vehicles	(1,189)	(1,189)	(1,246)	(1,294)	(1,443)	(1,619)	(1,810)	(2,016)	(2,239)	(2,470)	**(16,515)**
Less capitalised internal labour	(1,154)	(1,154)	(1,210)	(1,256)	(1,401)	(1,572)	(1,758)	(1,957)	(2,174)	(2,398)	**(16,034)**
Total	**28,263**	**28,263**	**32,643**	**33,948**	**38,029**	**42,525**	**47,882**	**53,127**	**58,993**	**64,900**	**428,573**
Totals from 1 April 2022 AMP	**23,190**	**24,789**	**23,850**	**24,333**	**24,966**	**25,837**	**26,657**	**27,562**	**28,702**	**n/a**	**n/a**

9.2.4 Capex – non-network

Table 9.2.4 Capex non-network – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Plant and vehicles	1,129	949	898	840	1,606	998	664	1,114	972	748	**9,918**
Technology and platform services	13,726	11,239	10,753	8,397	7,465	8,160	4,845	5,050	5,070	5,070	**79,775**
Corporate properties	640	275	275	275	275	275	275	275	275	275	**3,115**
Tools and equipment	1,391	565	515	815	525	565	515	815	515	575	**6,796**
Capitalised internal labour	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	**12,000**
Total	**18,086**	**14,228**	**13,641**	**11,527**	**11,071**	**11,198**	**7,499**	**8,454**	**8,032**	**7,868**	**111,604**
Totals from 1 April 2022 AMP	**12,961**	**11,891**	**12,246**	**12,073**	**9,787**	**7,444**	**6,924**	**7,551**	**7,643**	**n/a**	**n/a**

9.3 Total capital and operations expenditure

Table 9.3.1 Total capital and operations expenditure – $000

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	Total
Capital expenditure	153,770	145,060	205,969	263,289	273,182	318,693	348,636	391,671	426,840	456,492	**2,983,601**
Operational expenditure	78,186	82,786	104,648	109,888	119,504	130,104	137,109	148,449	158,122	169,044	**1,237,840**
Total	**231,956**	**227,846**	**310,617**	**373,177**	**392,686**	**448,797**	**485,745**	**540,120**	**584,962**	**625,536**	**4,221,441**
Totals from 1 April 2022 AMP	**185,678**	**170,611**	**199,785**	**200,080**	**193,433**	**190,572**	**192,388**	**194,614**	**195,038**	**n/a**	**n/a**

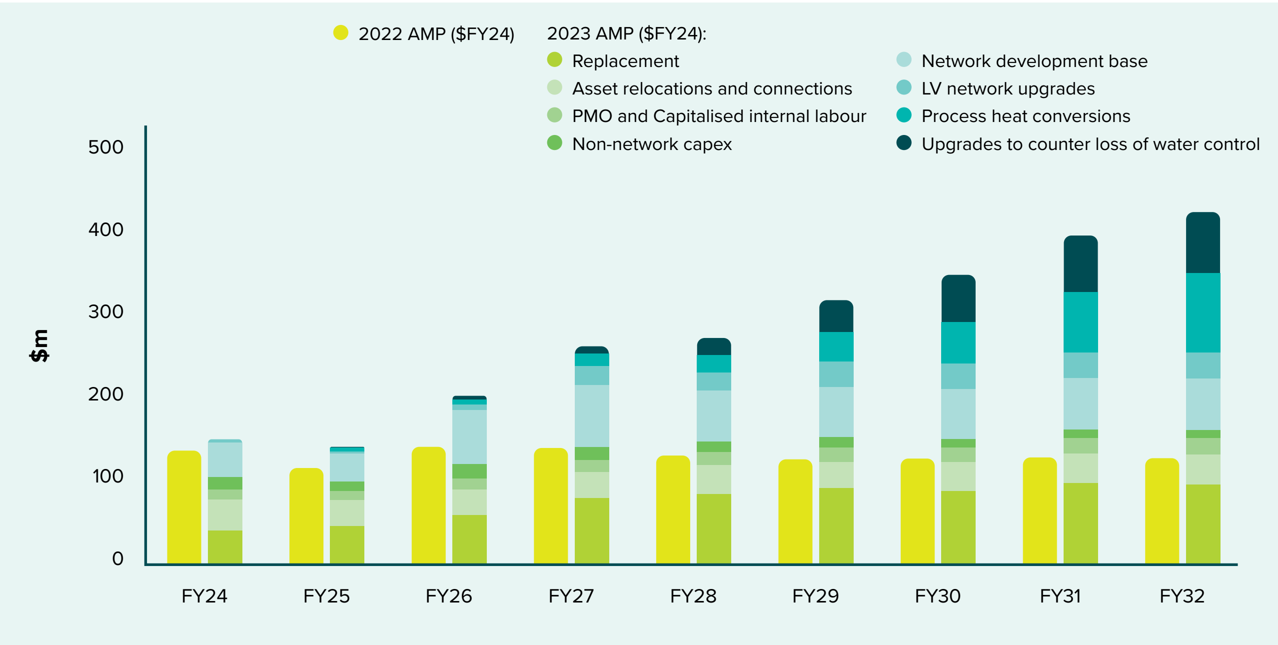
9.4 Changes from our previous forecasts

At Orion, we are dedicated to ensuring that our network functions as a service platform to support technology-driven customer choice and facilitate the transition to a low carbon energy system. Over the 9-year overlap with the previous AMP, there is a total increase of $1.5 billion in capex and $320 million in opex.

The decarbonisation of energy will significantly increase the reliance on electricity across all customer sectors. To enable and support this transition our network will play a vital role but will require substantial investment. This AMP is the first one to reflect this change in investment, resulting in notable changes to our 10-year forecast. The transition is occurring globally, so these changes are also driven by labour and material cost pressures. As the pace of decarbonisation accelerates, there is an anticipated surge in demand for electricity over the coming decades. To address this, we have increased our 10-year network development budget by 4.6 times for the 10-year period to reinforce our network. Figure 9.4.1 shows that the primary decarbonisation investment drivers are process heat conversion, impact of loss of hot water cylinder control and LV network upgrades. These are explained in more detail in Section 2.

In addition to the increase, our asset replacement budget has been increased by approximately 170% over the next decade to replace legacy assets that were installed in the 1960s to 1980s. We expect that both operating and capital expenditures for managing our assets will rise over the planning period to ensure that our network can withstand the impact of climate change, including changes in temperature, rainfall, extreme weather events, wind, and increased fire risk due to weather.

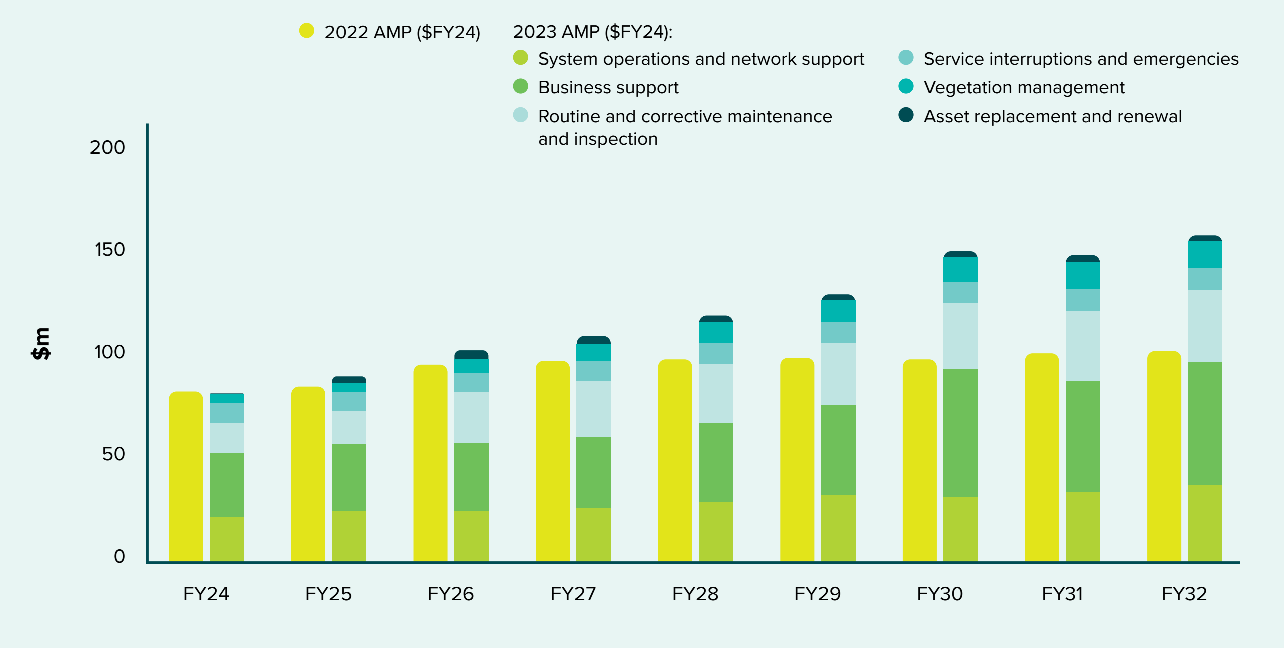
Figure 9.4.1



9.4 Changes from our previous forecasts continued

In light of the expansion of our asset base and the increasing complexity of our operations, it has become imperative to increase our employee numbers and training requirements and this is reflected in our non-network operational expenditure forecast. The network opex forecast also includes provisions for the procurement of flexibility services aimed at managing peak demand and accommodating data storage and management needs.

Figure 9.4.2



10

Our ability to deliver

Photo: Connetics crew at our Hawthornden Substation in Avonhead installing three new 66kV cables delivering power from our Islington substation. This provides greater capacity, flexibility and resilience to support new and existing customers in that area.

Contents

10.1 Introduction

This section describes our:

- approach to addressing our future workforce resourcing and capability needs, at Orion and sector level
- key philosophies, policies and processes that enable us to deliver our works programme and AMP objectives
- contract delivery process and how it enables us to consistently deliver our work safely, cost effectively and efficiently
- approach to managing the factors impacting delivery of our programme of work

Our plans include a step-change in the level of network investment over the period of this 10 year plan. To enable Orion to meet the challenges of the future, it will be necessary for us to lift our internal and external capability to deliver our ambitious and necessary plans.

To enable Orion to meet the challenges of the future, it will be necessary for us to lift our internal and external capability to deliver our ambitious and necessary plans.

10.2 Meeting future resourcing needs

With the significantly increased programme of works we and the rest of New Zealand's electricity sector are anticipating in the next few years, there is sector-wide consensus that the industry workforce will need to increase greatly in size. More complexity in the distribution system will also call for greater expertise and new skills. This is likely to coincide with a time of increasing demand for skilled electricity workers internationally.

We acknowledge it will be a challenge to adequately provide the skilled workforce to deliver our plan as our sector competes nationally and internationally for resources to deliver decarbonisation.

To address the challenge of whether we can deliver on our commitment to decarbonisation in the decades ahead, our sector recognises the need to develop new ways to grow our workforce's capability and size.

10.2.1 Building external capability

We share our future works plan with our Primary Service Delivery Partner (PSDP) and Project Management Office (PMO) and key service providers so they can prepare for increased workloads and the need for new skills in advance. However, we recognise the need to grow our industry's capability and workforce size is pressing, significant, and is a shared responsibility.

Orion is working with others in our sector to explore ways to address ways to build external capability, including:

- **cross sector collaboration** – we are in discussion with industry bodies, training organisations and government agencies to develop ways to address this issue
- **Energy Academy** – Energy Academy is an initiative of the Orion Group with the purpose of galvanising the industry to work on common challenges, such as redefining the roles of industry in tertiary training
- **supporting other industry competency initiatives** – Ara Trades Innovation Centre, which has an electricity distribution trades training centre, and University of Canterbury's Power Engineering Excellence Trust
- **established an Energy Hub and Energy Futures Lab** – to facilitate sector collaboration
- **designed the LUMO Global Energy Quest** – to build a culture of collaboration and innovation across the energy sector globally – supported by EECA, Ara Ake and BusinessNZ Energy Council

We acknowledge it will be a challenge to adequately provide the skilled workforce to deliver our plan.

10.2.2 Our workforce

The way we work is changing. From digitisation, automation of customer information through CRM, to line surveys using drones, Orion is focussed on implementing ways to simplify and make our processes more efficient. Our workforce will need to shift as service offerings develop and innovation changes how work is performed. We will need to develop new workforce skills and attributes as we move towards an automated and digitised workplace.

10.2 Meeting future resourcing needs continued

The key focus areas for Orion's workforce development over the next five years are:

- **Right people / Our people** – ensuring we understand the capability needs for the future and develop our talent profile to meet the needs of tomorrow's workforce. This will ensure our people thrive in our new environment and Orion attracts and sources the right people to enable our future growth
- **Right environment / Our place** – creating an environment that supports employee wellbeing and lifts performance through ensuring our workforce reflects the diverse communities we serve and embraces our differences. Amplifying the behaviours that reflect what we believe to be most important and enabling our workforce by ensuring our physical and digital work environment provides positive impacts
- **Right outcome / Our processes** – driving sustainable performance over time by ensuring our people have the confidence and capability to increase performance. Work is ongoing to develop programs that find opportunities for efficiency improvement, create team readiness for change and ensure any improvements are sustainable

The key activity we are undertaking to deliver on Orion's workforce development focus areas includes:

- **Capability framework, including people leadership** – a framework to define what the non-technical current and future capability looks like across Orion Group. The framework will be used to profile the business, identify gaps and show changes over time. It will also be used to underpin our talent and people structures as a common language for what good looks like
- **Identification, development, and selection of future skills and capabilities (5+ year view)** – a process to enable teams and business units to identify future skills and capabilities required to deliver their business plans. This process will support building strategic workforce plans
- **Strategic workforce planning (5+ year view)** – bringing together all our people insights both internal and external, and business strategy to create a strategic workforce plan – primary planning for skills and capability
- **Operational workforce planning (12 – 18 month view)** – enabling teams/business units to identify short-term workforce needs including: recruitment, retention and reskilling and create people plans to support the delivery of business plans
- **Learning and Development Programmes:**
  - **Orion Development Programme, Technical** – we apply a structured approach to training our future leaders for the industry through a four year programme that develops practical and theoretical understanding of engineering
  - **Orion Development Programme, Graduate** – since 2020 this programme has taken on a university graduate to complete a two year placement rotation through various areas of our business
- **Diversity, equity and inclusion programme, Ubuntu** – a programme of work to ensure Orion reflects the diverse community it serves, and the Orion Group is a place where all employees feel a sense of belonging and where our people can be their whole selves and thrive

10.3 Service providers

Orion engages contractors and consultants, who we call service providers, to design, construct, maintain and dispose of our network assets.

Our service providers don't have direct network management responsibilities for our assets – we engage them for specified scopes of work or for contracts over specific periods to meet the needs of our asset management objectives.

The key objective of our contractual relationships is to ensure the safety, quality and capability of both our people and the work being delivered. It also ensures services and materials are delivered on time, at an agreed cost and to specified requirements. Our contracts are mainly founded on AS/NZS standard conditions for capital, maintenance, and emergency works contracts.

Our Procurement Manual sets the framework for authorised service providers to meet our asset management objectives. Authorisation to undertake works on our network is subject to a formal contractual agreement which specifies the work categories that each service provider can undertake for us. Service providers are responsible and accountable for the requirements of the base contract, and the specific conditions attached to specific projects or works orders.

When special circumstances arise, for example, a project that requires specialist skills, we may invite other suitably experienced and competent service providers to tender for the work.

We welcome expressions of interest from suppliers who wish to become authorised service providers for our network, and we have a process that allows for this. We maintain a service provider register which details the work categories that can be undertaken by each provider – and we audit those providers at appropriate intervals and times to ensure they still comply with our requirements and specifications.

We monitor our service providers by work types on an ongoing basis to ensure our overall service provider competence, capability and health and safety objectives are being met.

10.4 Contract delivery for works

For construction and maintenance services of our overhead, substation and underground assets, we have transitioned away from a lowest conforming tender model to a Primary Service Delivery Partner (PSDP) contracting model. Connetics undertakes the role of the PSDP and through a dedicated arms-length Project Management Office (PMO) plans and contracts work from a number of service providers, including Connetics.

The PSDP relationship enables a long-term partnership approach rather than a short term transactional approach by providing a contractual framework that incentivises the long term development and maintenance of the resources and capabilities Orion needs. The framework is also expected to provide better overall long-term value and control of costs.

The new contract delivery framework began operation in October 2021 and already we have seen improvements in workforce planning and resource allocation. We are also noting benefits in terms of increased cross service provider collaboration on projects, utilising the skills of multiple service providers to complete extensive projects more efficiently and in the best long term interest of our customers. We are finetuning and developing systems and processes to support the framework's operational efficiency and ability to meet the established outcomes.

The PMO uses a number of procurement methodologies for assessing and awarding works and apply unit rates where work is repeatable.

For our contract delivery framework see Figure 10.1.1.

This way of contracting our significant network maintenance and construction work is designed to enable Orion to meet the following outcomes more effectively and efficiently:

- identify future resources and capability needed
- support and enhance safety
- drive increased quality and efficiency
- develop people within the Orion Group and across the industry
- deliver the resilience that Orion requires
- comply with our legal and regulatory framework
- contribute to Orion delivering on our Purpose and Group Strategy

Orion's Procurement team maintains the contract and service level measures that are in place with Connetics in its role as our PMO.

Our Network Delivery team is responsible for ensuring our work is being delivered in a way that achieves long-term value for our customers. The team does this by monitoring value to ensure lowest overall cost to the customer as well as monitoring the service levels being achieved. This team is supported as appropriate by our operations and engineering teams.

Our Works Management information management system supports administrative processes – including tenders, contracts, audit information and financial tracking.

The PSDP relationship enables a long-term partnership approach rather than a short term transactional approach.

Procurement of consultancy design services, property related services, vegetation management services and major equipment items are not a part of the PSDP model. Customer initiated work is procured outside the PSDP model but will still utilise the same service providers.

10.4.1 Works programme

Our larger customer initiated works and growth projects are prioritised by our project prioritisation process, set out in Section 5. Our replacement and maintenance programmes are set out in Section 6.

10.4.2 Procurement

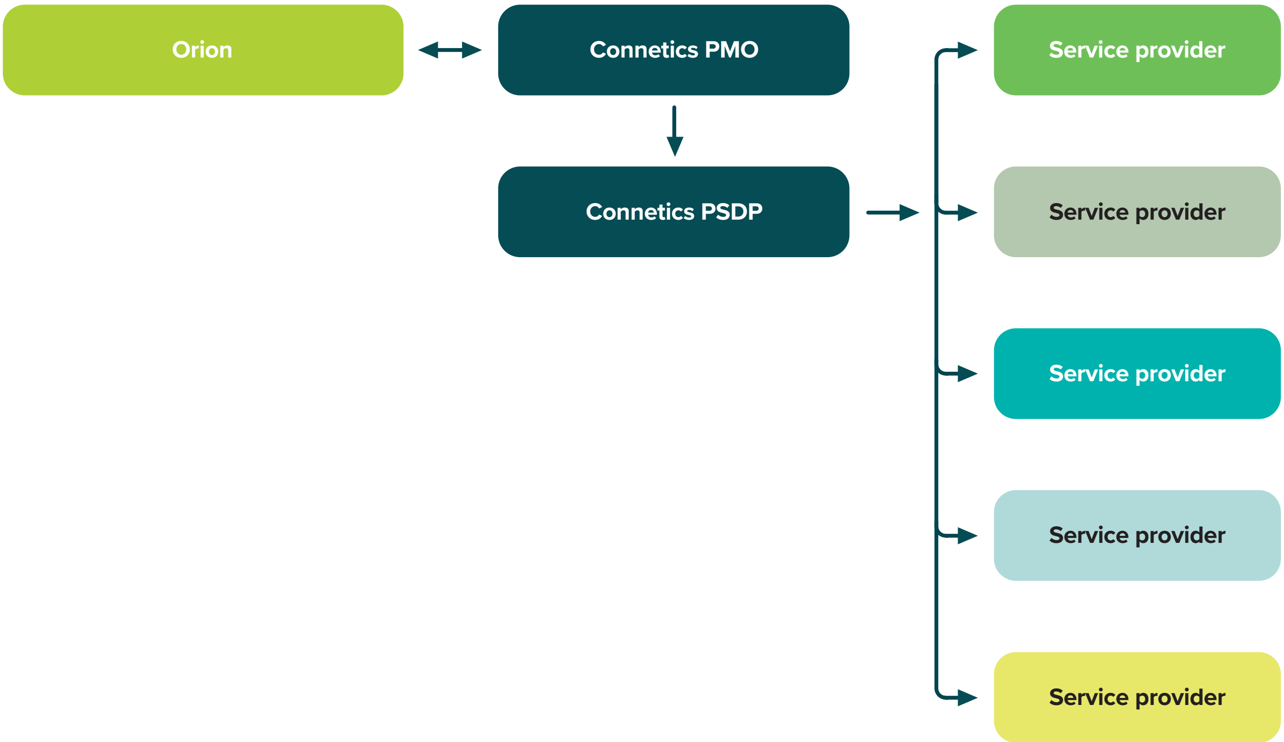
We adopt a risk based approach to our key procurement decisions, while ensuring levels of authority that allow for the efficient delivery of our asset management objectives. Our Procurement Policy outlines our strategic approach to procurement. Our key network risks and our proposed network development priorities for the next period are outlined elsewhere in this AMP.

Our contract delivery process recommends formal procurement contracts with suppliers and service providers where the value or risk is considered high, complex, novel or likely to attract media attention, or come under significant public scrutiny. We have a variety of procurement options within our contract delivery framework which allow for flexibility in both contract options and conditions.

Using the five Government Procurement Principles to guide our actions, see Figure 10.1.2. We aim to have fair and transparent procurement processes that are free from fraud and impropriety, and are sustainable from economic, risk, legal, community, and environmental perspectives. We follow good procurement practice by:

- procuring fit-for-purpose goods and services
- considering whole-of-life costs of goods and services when procuring
- being cost conscious and considering value for money
- identifying, assessing and managing our procurement risks – financial and non-financial
- managing and mitigating any potential conflicts of interest in an open and collaborative manner
- complying with our legal and contractual obligations

Figure 10.4.1 Orion contract delivery framework



- continuous improvement
- ensuring sustainability and consideration of social outcomes are included in our planning

Orion's key policies which also provide procurement guidelines include our Delegations of Authority and Fraud and Theft policies. Our Delegations of Authority policy outlines our general expenditure and approval rules and details the expenditure authorities that allow our people to expediently deliver our AMP and asset management objectives, including approved and unapproved expenditure. It also details authority limits for asset disposals, and research and development.

10.4.3 Procurement of equipment

Tenders are our preferred method of engagement for the supply of major equipment.

We consider the benefits of all tendering models for each major procurement to ensure the best outcomes for our network and our stakeholders.

We assess tenders for equipment supply following a robust assessment using weighted attributes such as price, technical support, sustainability and experience and reputation.

We aim to maintain fair relationships with our service providers and seek to deliver our works at a whole of life cost that is in the long-term interest of our customers. We recognise the importance equipment suppliers play.

10.4.4 Resourcing works delivery

We manage our service delivery and efficient delivery of our work programme utilising both our own teams and that of service providers:

- **internal resources** – the Orion team and its structure are described in Section 8 of this AMP. Section 8 also provides comprehensive overviews and the responsibilities of each business support area and how their capabilities help deliver our asset management objectives.
- **service providers** – in conjunction with the PMO, we work with our service provider resources to 'smooth' our opex and capex works as much as practical to avoid unnecessary resource peaks and troughs. This has two key benefits. First, our service providers avoid the need to substantially 'gear-up' or 'gear-down' their resources for short term peaks. Second, it provides our service providers with more certainty. We have engaged with the PMO on our forecast increase in works to ensure they hold early conversations with all service providers about the workforce size and skills needed.

We proactively work with our PMO to assess the levels of people resources necessary to deliver our objectives, to the extent that is practical, while investing in competence and capability. This provides for a base level of ongoing planned work and people who can be quickly redirected to areas of greater need following High-Impact-Low-Probability events.

10.4 Contract delivery for works continued

Our Works General Requirements document sets overarching expectations on our service providers that:

- work shall be carried out safely, on time and cost efficiently, while ensuring customer satisfaction
- only authorised personnel may undertake work on our network
- service providers shall have appropriate management systems in place to deliver contractual obligations
- the preferred methods and controls to plan, execute, monitor, control and close out works

Our Emergency Works Requirements covers our expectations for urgent work – for example, due to weather events, network failure or safety reasons. In this document we describe:

- the up-front resources and contingency measures we require service providers to have at all times
- how to prioritise emergency works
- the requirement for service providers to redeploy their resources to us in a major emergency
- the use of authorised personnel for emergency work
- the methods and controls for network access during emergency work
- the requirements for regular response and restoration time assessments
- the levels and controls for emergency spares

10.4.5 Audit and performance monitoring

We audit our contract delivery process using an audit management guide based on an AS/NZS standard, and we have a dedicated team, supported by external experts as appropriate, for this. Our audit process allows for the identification of health and safety hazards, conflicts of interest and contractual or technical non-conformances.

We review longer term contracts for continual performance improvement and to enable new initiatives as they arise.

We monitor our contract performance against our conditions of contract.

Our key objective when monitoring contract performance is continuous improvement including:

- enhanced collaborative and positive relationships with our PSDP and service providers
- consistent reporting and tracking of contract performance indicators
- the provision of information that allows for reporting, benchmarking and trend analysis
- enhancing our customer experience by ensuring our service providers are focussed on customer satisfaction

Figure 10.4.2 Government Procurement Principles

10.4.6 Delivery

We deliver our programme of planned and emergency works using our PSDP, our PMO, service providers, and our in-house team based in our Christchurch office.

Our Network Delivery team is responsible for the works programming and delivery of our annual work plan in conjunction with our PMO, supported as appropriate by our other teams. They use our robust contract delivery processes to safely construct, maintain and develop our network to achieve our objectives. Our other in-house teams, as shown in Section 8 of this AMP, provide and administer the vital business, customer engagement and information support functions that enable the successful delivery of our works programme.

We provide a highly responsive service to our customers and community when managing situations where our network capacity in localised areas may be constrained or compromised by other parties. We provide the ability for customers to connect to our network, or alter their connection type or capacity, in a timely manner.

10.4.7 Managing factors affecting project delivery

During the past two years we have had new pressures on our ability to deliver our project plans, pressures which have called on us to be agile and flexible in our planning and approach to how we work. The impacts of the COVID-19 pandemic continue to create supply chain issues for us and while these are declining in severity, there remains a long tail as the pandemic recedes in severity.

The COVID-19 pandemic has impacted our delivery programme in a number of ways causing delays to our expected completion dates. We have been dealing with the impact of the pandemic on two fronts. Localised impact has required us to prioritise service provider resources as a result of sickness across our total works portfolio. This has impacted on our efficiency to deliver as we have moved resources across our portfolio of projects to actively manage this.

The second front is the remote impact, which has driven supply chain delays as equipment providers are unable to supply equipment in a timely manner. An example of this is the delivery time for switchgear which was previously delivered within six months and has now increased to 15 months. Delays in the supply of equipment have also been due to sickness in overseas manufacturing staff causing a backlog of supplier equipment requests. This has been exacerbated by a shipping freight backlog which has caused uncertainty with delivery dates.

Our programming of works around these variables has been extremely complex to ensure project works continue and keep service providers viable through these periods. To alleviate the impact we have decoupled work packages and used lateral thinking to provide work arounds that enable us to maintain momentum, though often at to the detriment of efficiency.

We have also experienced delays with local government agencies in processing consent times because of regional growth putting pressure on their resources to meet delivery dates.

In summary, factors impacting on our ability to deliver are:

- uncertainty on delivery timeframes, delays and cost escalation of both commodities and equipment
- ongoing COVID-19 impacts on employee sick leave and supply chain delays
- a shortage of skilled trained staff as our people and those of service providers are lured to more lucrative roles overseas and we compete with other EDBs with ambitious work programmes
- changes in work practices that expand crew requirements
- shortfall in project delivery carried over from FY22
- significant, necessary readjustments to our work programme soaking up planning time
- increased level of interest from industrial process heat users with short timeframes to use electrification to decarbonise their operations

Compounding pressure on our ability to deliver our wider programme of work, our accelerated pole inspection and replacement programme has drawn on our service provider's overhead lines resources. We have prioritised this programme as a known public safety risk.

We are managing these factors to deliver our works programme by:

- being flexible – moving projects around in the schedule
- being agile – responding to changes at short notice with alternatives and other options
- reviewing our procurement model to increase the range of equipment items we hold stock of and increasing stock holdings of standard items such as power poles
- ordering equipment with longer lead times
- targeting our poles assessment programme to prioritise high risk poles species and working more efficiently
- bringing in people from other regions to assist
- through our Energy Academy initiative, we are also exploring options to increase wider industry training and competence development

While we make every effort to complete our planned work programme each year, extraordinary circumstances over the past three years have necessitated some adjustments to project timings. Key projects carried over from last year's AMP are:

- Heathcote switchgear replacement
- Norwood to Dunsandel line build

10.5 Conclusions on our ability to deliver our forecast work programme

We are confident in our ability to deliver our forecast opex and capex programmes as detailed in our AMP, given:

- we are continuing to invest in the capability of the Orion team, and are working with industry and training partners to build the workforce size and capability through our Energy Academy and other initiatives
- we plan our opex and capex spend over the next five to ten years – this provides certainty for our PSDP and other key service providers to continue to invest in their resource and capability to meet our needs
- we have restructured our operational teams to efficiently deliver our work programme
- being conscious of not wanting to take on more than we can deliver, we have looked critically at our work programme, and pared back expenditure in some key areas to keep costs and resourcing within our capability and to support customer affordability
- we have a partnership approach with our PSDP and other service providers and by engaging with them on our long term proposed works programme, they are able to plan ahead to resource to meet our needs

Development of the workforce availability and skills will take time and a key dependency is ensuring our regulatory regime recognises our need to invest in developing this capability.

We have set ourselves an ambitious plan over the next ten years and recognise there are a range of uncertainties in the environment in which we operate. While these may impact on our capacity to deliver individual projects, the experience we have gained over many years and more recently over the past three years has equipped us well to manage our programme of work in a more fluid environment. We will continue to invest in the capability required, both internal and external, to deliver on our forward works plan.

Through improved forward planning, the adoption of our new contract delivery framework and our increased skill in performing with greater flexibly and with more agility, Orion is confident we can undertake the projects we have set out in this plan that will enable us continue to maintain and develop our network to meet our customer's needs.

We have set ourselves an ambitious plan over the next ten years and recognise there are a range of uncertainties in the environment in which we operate.

Appendices

Photo: Virtual reality creates an immersive environment, made possible by power to both render and display the content.

Contents

Appendix A Glossary of terms

A: Ampere; unit of electrical current flow, or rate of flow of electrons.

ABI: Air Break Isolator; a pole mounted isolation switch. Usually manually operated.

AC: Alternating current; a flow of electricity which reaches maximum in one direction, decreases to zero, then reverses itself and reaches maximum in the opposite direction. The cycle is repeated continuously.

ADMS: Advanced Distribution Management System; a software package to control and optimise the operation of an electrical distribution network.

Alpine Fault: a geological fault, specifically a right-lateral strike-slip fault that runs almost the entire length of New Zealand's South Island. It has an average interval for a major earthquake at every 290 years, plus or minus 23 years. The last major Alpine Fault earthquake occurred in 1717. The longest known major Alpine Fault earthquake return rate is believed to be around 350 years and the shortest around 160 years.

AMP: Asset Management Plan.

Biofuel / Biomass: Biofuels are any fuel produced from biological matter or 'biomass'. This can include agricultural and forestry crops and residues, organic by-products, and waste such as used cooking oil. Biofuels can help reduce emissions and contribute towards meeting Aotearoa New Zealand's climate targets.

Biodiesel: a renewable, biodegradable fuel manufactured from vegetable oils, animal fats, or recycled restaurant grease.

Bushing: an electrical component that insulates a high voltage conductor passing through a metal enclosure.

Capacitance: the ability of a body to store an electrical charge.

Capacity utilisation: a ratio which measures the utilisation of transformers in the network. Calculated as the maximum demand experienced on an electricity network in a year, divided by the transformer capacity on that network.

CB: Circuit breaker; a device which detects excessive power demands in a circuit and cuts off power when they occur. Nearly all of these excessive demands are caused by a fault on the network. In the urban network, where most of these CBs are, they do not attempt a reclose after a fault as line circuit breakers may do on the rural overhead network.

CBRM: Condition Based Risk Model; a modelling programme which combines asset information, observations of condition and engineering knowledge and experience to produce a measure of asset health, the CBRM Health Index. The model also produces forecasts of asset probability of failure, and a measure of asset related risk in future years which can be used for developing optimised asset renewal plans.

CCC: Christchurch City Council; the local government authority for Christchurch in New Zealand.

Continuous rating: the constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely effecting it characteristics.

Conductor: the 'wire' that carries the electricity and includes overhead lines which can be covered (insulated) or bare (not insulated) and underground cables which are insulated.

CPP: Customised Price-Quality Path Determination set by the Commerce Commission for Orion and in effect from FY15 to FY19. This determination applied to Orion to cover the extraordinary period of network rebuilding during recovery from the Canterbury earthquakes.

CRM: a customer relationship management system or software that helps track information and interactions between a company and its customers, with the goal of improving relationships and outcomes.

Current: the movement of electricity through a conductor, measured in amperes (A).

Customer Demand Management: shaping the overall customer load profile to obtain maximum mutual benefit to the customer and the network operator.

DER: Distributed Energy Resources; the capacity for customers to generate and store their own energy from sources including solar and wind will see electricity fed into grids locally, from households and businesses.

DERMS: Distributed Energy Resources Management System; a software platform used to manage a group of distributed energy resources.

DIN: Deutsches Institut für Normung; the German Institute for Standardisation. Equipment manufactured to these standards is often called 'DIN Equipment'.

Distribution substation: is either a building, a kiosk, an outdoor substation or pole substation taking its supply at 11kV and distributing at 400V.

DPP: Default Price-Quality Path 2020-25; applies to electricity lines businesses that are subject to price-quality regulation and is set by the Commerce Commission. It sets the maximum allowable revenue that the businesses can collect. It also sets standards for the quality of services that each business must meet.

DSO: Distribution System Operator; an entity responsible for distributing and managing energy from the transmission grid and other generation sources to the final consumers.

EV: Electric Vehicles; a vehicle that uses electricity for propulsion.

Fault current: the current from the connected power system that flows in a short circuit caused by a fault. Feeder: a physical grouping of conductors that originate from a zone substation circuit breaker.

Flashover: a disruptive discharge around or over the surface of an insulator.

Flexibility services: are a range of existing and developing solutions that electricity system users can provide to help balance demand and supply in the electricity network and support its efficient use. Flexible technologies such as electric vehicles and solar can provide 'flexibility services' to electricity networks. By releasing power back to the grid at times of high demand, and storing it during times of lower demand, local 'flexibility services' unlock additional capacity and avoid network over-build.

Frequency: on alternating current circuits, the designated number of times per second that polarity alternates from positive to negative and back again, expressed in Hertz (Hz)

Fuse: a device that will heat up, melt and electrically open the circuit after a period of prolonged abnormally high current flow. Gradient, voltage: the voltage drop, or electrical difference, between two given points.

GXP: Grid exit point; a point where Orion's network is connected to Transpower's transmission network.

GIDI Fund: Government Investment in Decarbonising Industry Fund. The GIDI Fund was launched in 2020 to accelerate the decarbonisation of industrial process heat – and is a partnership between Government and businesses.

Harmonics (wave form distortion): changes an AC voltage waveform from sinusoidal to complex and can be caused by network equipment and equipment owned by customers including electric motors or computer equipment.

HILP: High-Impact-Low-Probability; an event that is not likely to occur but will have significant consequence to an organisation.

HV: High voltage; voltage exceeding 1,000 volts (1kV), in Orion's case generally 11kV, 33kV or 66kV.

ICP: installation control point; a uniquely numbered point on our network where a customer(s) is connected.

Inductance: is the property of a conductor by which current flowing through it creates a voltage (electromotive force) in both the conductor itself (self-inductance) and in any nearby conductors.

Insulator: supports live conductors and is made from material which does not allow electricity to flow through it.

Interrupted N-1: a network is said to have 'Interrupted N-1' security or capability if following the failure of 'one' overhead line, cable or transformer the network can be switched to restore electricity supply to customers.

Interrupted N-2: a network is said to have 'Interrupted N-2' security or capability if following the failure of 'two' overhead line, cable or transformer the network can be switched to restore electricity supply to customers.

ISO 55000: International Standards for Asset Management.

kV: Kilovolts; 1,000 volts.

kW: Kilowatt; a unit of electric power, equal to 1000 watts.

kWh: Kilowatt hour; a unit of energy equal to one kilowatt of power sustained for one hour.

kVA: Kilovolt-ampere; an output rating which designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.

LCB: Line circuit breaker; a circuit breaker mounted on an overhead line pole which quickly cuts off power after a fault so no permanent damage is caused to any equipment. It switches power back on after a few seconds and, if the cause of the fault has gone, (e.g. a branch has blown off a line) then the power will stay on. If the offending item still exists then power will be cut again. This can happen up to three times before power will stay off until the fault is repaired. Sometimes an LCB is known as a 'recloser'.

Legacy assets: assets installed to meet appropriate standards of the time, but are not compliant with current day safety standards.

Lifelines groups: local collaborations between lifeline utilities. They aim to reduce infrastructure outages, especially if HILP events occur. It was this collaboration that lead us to invest to strengthen our key substations before the Canterbury earthquakes.

LV: Low voltage; a voltage not exceeding 1,000 volts, generally 230 or 400 volts.

Maximum demand: the maximum demand for electricity, at any one time, during the course of a year.

MW: Megawatt; a unit of electric power, equal to 1000 kilowatts.

MWh: Megawatt hour; a unit of energy equal to one Megawatt of power sustained for one hour.

N: a network is said to have 'N' security or capability if the network cannot deliver electricity after the failure of 'one' overhead line, cable or transformer.

N-1: a network is said to have 'N-1' security or capability if the network continues to deliver electricity.

N-2: a network is said to have 'N-2' security or capability if the network continues to deliver electricity after the failure of 'two' overhead lines, cables or transformers.

Network deliveries: total energy supplied to our network through Transpower's grid exit points, usually measured as energy supplied over the course of a year.

Network substations: are part of Orion's primary 11kV network all within the Christchurch urban area.

Ohm: a measure of the opposition to electrical flow, measured in ohms.

Open network framework: in an open network framework anyone can connect and use any equipment they want to buy or sell electricity services – including solar, batteries. An open network framework also enables the trading of electrical energy and capacity between consumers and market participants using the electricity distribution network.

ORDC: optimised depreciated replacement cost, prepared in accordance with New Zealand International Financial Reporting Standards (NZ IFRS) under International Accounting Standard NZ IAS 16 – Property, Plant and Equipment as at 31 March 2007.

Outage: an interruption to electricity supply. Power cut.

PCB: Polychlorinated biphenyls (PCBs) were used as dielectric fluids in transformers and capacitors, coolants, lubricants, stabilising additives in flexible PVC coatings of electrical wiring and electronic components. PCB production was banned in the 1970s due to the high toxicity of most PCB congeners and mixtures. PCBs are classified as persistent organic pollutants which bio-accumulate in animals.

PMO: Project Management Office.

Proven voltage complaint: a complaint from a customer concerning a disturbance to the voltage of their supply which has proven to be caused by the network company.

PSDP: Primary Service Delivery Partner.

PV: Photovoltaics; panels which convert light into electricity, commonly known as solar panels.

Ripple control system: a system used to control the electrical load on the network by, for example, switching domestic water heaters, or by signaling large users of a high price period. Also used to control streetlights.

RTU: Remote Terminal Unit; part of the SCADA system usually installed at the remote substation.

SAIDI: System Average Interruption Duration Index; an international index which measures the average duration of interruptions to supply that a customer experiences in a given period.

SAIFI: System Average Interruption Frequency Index; an international index which measures the average number of interruptions that a customer experiences in a given period.

SCADA: System Control and Data Acquisition.

SDC: Selwyn District Council; the territorial authority for the Selwyn District of New Zealand.

STATCOM: Static Synchronous Compensator; a power electronic device which regulates voltage by providing or absorbing reactive power.

Transformer: a device that changes voltage up to a higher voltage or down to a lower voltage.

Transpower: the state owned enterprise that operates New Zealand's transmission network. Transpower delivers electricity from generators to grid exit points (GXPs) on distribution networks throughout the country.

Voltage: electric pressure; the force which causes current to flow through an electrical conductor. Voltage drop: is the reduction in voltage in an electrical circuit between the source and load.

Voltage regulator: an electrical device that keeps the voltage at which electricity is supplied to customers at a constant level, regardless of load fluctuations.

ZS: Zone substation; a major substation where either; voltage is transformed from 66 or 33kV to 11kV, two or more incoming 11kV.

Appendix B Cross reference table

As our AMP has been structured as a practical planning tool, it does not strictly follow the order laid out in the Electricity Distribution Information Disclosure Determination 2012. We have prepared the cross reference table below to help the reader find specific sections.

Sections as per the Electricity Distribution Information Determination 2012	Orion AMP SECTION
1. Summary of the plan	1 Executive summary
2. Background and objectives	2 Our strategy
	5 Our planning approach
	8 Supporting our business
3. Assets covered	5 Our planning approach
	6 Managing our assets
4. Service levels	4 Customer experience
5. Network development plans	7 Developing our network
	9 Financial forecasting
	10 Our ability to deliver
6. Lifecycle asset management planning (maintenance and renewal)	6 Managing our assets
	9 Financial forecasting
	10 Our ability to deliver
7. Risk management	3 Managing risk
8. Evaluation of performance	2 Our strategy
	4 Customer experience
	9 Financial forecasting

Appendix C Asset data

Data currently held in our information systems for the asset group can be found in the table below.

Data class	Network property	Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Protection systems	Communication cables	Communication systems	Distribution management system	Load management systems	Information systems	Generators	Monitoring
Location	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Type	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Age	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Seismic risk assessment	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Test/inspection results	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Ratings		✓	✓	✓	✓	✓	✓	✓	✓	✓		✓					✓	
Serial numbers								✓	✓	✓	✓						✓	✓
Movement history								✓	✓	✓	✓							
Circuit diagrams		✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓					
Connectivity model		✓	✓	✓	✓	✓	✓					✓						
Conductor size		✓	✓	✓	✓	✓	✓					✓						
Joint details					✓	✓												
Pole ID labels		✓	✓	✓														
Oil analysis									✓	✓								

Appendix D Specifications and standards (assets)

		Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Design standards	**Document ID**															
Network design overview	NW70.50.05	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Safety in design	NW70.50.07	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Overhead line design standard	NW70.51.01	■	■	■					■							
Overhead line design manual	NW70.51.02		■	■												
Overhead line design worked examples	NW70.51.03		■													
Overhead line design technical manual	NW70.51.04		■													
Cable distribution design	NW70.52.01					■	■	■	■							
Distribution substation design	NW70.53.01								■	■	■		■	■		■
Protection design	NW70.57.01								■	■			■			
Earthing system design	NW70.59.01								■	■						
Subtransmission protection design	NW70.57.02												■			
Distribution feeder and transformer protection	NW70.57.03												■			
SCADA functional specification for remote sites	NW70.56.01														■	
Substation design – customer premises	NW70.53.02															■
Technical Specifications	**Document ID**															
Works general requirement	NW72.20.04															
Overhead line work	NW72.21.01		■	■												
Overhead line re-tighten components	NW72.21.03	■	■	■												
Tower painting	NW72.21.05	■														
Tower maintenance painting	NW72.21.06	■														
Tower inspections	NW72.21.19	■														
Overhead line inspection and assessment	NW72.21.11	■	■	■												
Thermographic survey of high voltage lines	NW72.21.10	■	■													
Standard construction drawing set – Overhead lines	NW72.21.18	■	■	■												

Technical Specifications	Document ID	Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Vegetation work adjacent to overhead lines.	NW72.24.01	■	■	■												
Cable installation and maintenance	NW72.22.01				■	■	■	■								
Excavation, backfilling and restoration of surfaces	NW72.22.02				■	■	■	■								
Standard construction drawing set – Underground	NW72.21.20				■	■	■	■								
Cable testing	NW72.23.24				■	■	■	■								
Cabling and network asset recording	NW71.12.03				■	■	■	■								
Distribution cabinet installation	NW72.22.03						■									
Distribution box installation	NW72.22.10						■									
LV underground network inspection	NW72.21.12						■									
Unit protection maintenance	NW72.27.01							■					■			
Zone substation inspection	NW72.23.13								■	■						
Zone substation maintenance	NW72.23.07								■	■						
Disposal of asbestos	NW70.10.25								■	■						
Hazardous substances	NW70.10.02								■	■						
Standard construction drawing set – high voltage plant	NW72.21.21								■	■	■					
OCB servicing after operation under fault conditions	NW72.23.15								■							
Partial discharge tests	NW72.27.03								■							
Air break isolator maintenance – 11kV	NW72.21.04								■							
Distribution substation inspection	NW72.23.03								■		■					
Distribution substation maintenance	NW72.23.05								■		■					
Network substation inspection	NW72.23.04								■		■					
Network substation maintenance	NW72.23.06								■		■					
Environmental management manual	NW70.00.08								■		■					

		Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Technical Specifications	**Document ID**															
Power transformer servicing	NW72.23.25															
Mineral insulating oil maintenance	NW72.23.01															
Transformer installations (distribution)	NW72.23.16															
Transformer maintenance (distribution)	NW72.23.02															
Testing and commissioning of secondary equipment	NW72.27.04															
Ripple control system details	NW70.26.01															
Ripple equipment maintenance	NW72.26.02															
SCADA master maintenance	NW72.26.04															
SCADA RTU maintenance	NW72.26.05															
Kiosk installation	NW72.23.14															
Graffiti removal	NW72.22.11															
Equipment Specifications	**Document ID**															
Poles – softwood	NW74.23.06															
Poles – hardwood	NW74.23.08															
Insulators – high voltage	NW74.23.10															
Conductor – overhead lines	NW74.23.17															
Cross-arms	NW74.23.19															
Earthing equipment and application	NW74.23.20															
Cable Subtransmission – 33kV	NW74.23.14															
Cable Subtransmission – 66kV – 300mm2 Cu XLPE	NW74.23.30															
Cable Subtransmission – 66kV – 1,600mm2 Cu XLPE	NW74.23.31															
Cable Subtransmission – 66kV – 1,000mm2 Cu XLPE	NW74.23.35															
Distribution cable 11kV	NW74.23.04															
Distribution cable LV	NW74.23.11															
Communication cable	NW74.23.40															

		Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Equipment Specifications	**Document ID**															
Switchgear – 400V indoor	NW74.23.23								●							
Circuit breaker – 66kV	NW74.23.25								●							
Circuit breaker – 33kV indoor	NW74.23.28								●							
Major power transformer 7.5/10MVA 66/11kV	NW74.23.07									●						
Voltage regulator 11kV	NW74.23.15									●						
Major power transformer 11.5/23MVA 66/11kV	NW74.23.16									●						
Major power transformer 2.5MVA 33/11kV	NW74.23.22									●						
Major power transformer 20/40MVA 66/11kV	NW74.23.24									●						
Transformers – distribution	NW74.23.05										●					
Ripple control system	NW74.23.09													●		
Kiosk shell – full	NW74.23.01															●
Kiosk shell – half	NW74.23.02															●
Kiosk shell – quarter	NW74.23.03															●
Asset management reports	**Document ID**															
AMR – Protection Systems	NW70.00.22												●			
AMR – Power Transformers	NW70.00.23									●						
AMR – Switchgear HV and LV	NW70.00.24								●							
AMR – Overhead Lines – LV	NW70.00.25			●												
AMR – Overhead Lines – Subtransmission	NW70.00.26	●														
AMR – Overhead Lines – 11kV	NW70.00.27		●													
AMR – Cables – Communication	NW70.00.28							●								
AMR – Cables – LV and Hardware	NW70.00.29						●									
AMR – Cables – 11kV	NW70.00.30					●										
AMR – Cables – 33kV	NW70.00.31				●											
AMR – Cables – 66kV	NW70.00.32				●											
AMR – Circuit Breakers	NW70.00.33								●							

Asset management reports	Document ID	Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
AMR – Communication Systems	NW70.00.34												■	■	■	
AMR – Distribution Management	NW70.00.36														■	
AMR – Load Management	NW70.00.37													■		
AMR – Monitoring	NW70.00.38													■	■	
AMR – Generators	NW70.00.39											■				
AMR – Transformers – Distribution	NW70.00.40										■					
AMR – Voltage Regulators	NW70.00.41									■						
AMR – Property – Corporate	NW70.00.42															■
AMR – Property – Network	NW70.00.43															■
AMR – Substations	NW70.00.44															■
AMR – Vehicles	NW70.00.47															■
AMR – Information Systems (Asset Management)	NW70.00.48												■	■	■	
AMR – Information Systems (Corporate)	NW70.00.49												■	■	■	

Appendix E Specification and standards (network planning)

Design standards	Document ID
Network architecture review: subtransmission	NW70.60.16
Urban 11kV network architecture review	NW70.60.06
Network design overview	NW70.50.05
Project prioritisation and deliverability process	NW70.60.14
Long term load forecasting methodology for subtransmission and zone substation	NW70.60.12
Demand side management stage 1 – issues and opportunities	NW70.60.10
Demand side management stage 2 – potential initiatives	NW70.60.11

Appendix F Disclosure schedules 11-13

This section contains the Information disclosure asset management plan schedules.

Schedule	Schedule name
11a	Report on forecast capital expenditure
11b	Report on forecast operational expenditure
12a	Report on asset condition
12b	Report on forecast capacity
12c	Report on forecast network demand
12d	Report forecast interruptions and duration
13	Report on asset management maturity

Schedule 11a. Report on forecast capital expenditure

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2023 – 31 March 2033

7		Current year	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 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	31 Mar 33
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	22,207	33,012	44,679	58,493	56,848	52,908	71,473	91,662	123,528	156,861	197,638
11	System growth	14,358	25,710	21,899	42,437	81,940	104,387	145,121	172,646	186,584	203,103	213,907
12	Asset replacement and renewal	32,234	36,529	42,206	61,170	84,364	92,785	107,505	108,878	117,379	126,044	126,208
13	Asset relocations	7,560	12,773	10,576	9,024	8,920	12,343	8,159	11,026	11,271	11,531	11,805
14	Reliability, safety and environment:											
15	Quality of supply	14,297	18,144	5,400	23,702	31,281	20,089	13,979	12,985	18,744	15,128	13,521
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	11,003	9,516	9,814	7,991	8,838	8,021	3,208	272	278	285	292
18	**Total reliability, safety and environment**	25,300	27,660	15,214	31,693	40,119	28,110	17,187	13,258	19,023	15,413	13,813
19	**Expenditure on network assets**	101,659	135,684	134,574	202,817	272,191	290,533	349,444	397,470	457,784	512,952	563,371
20	Expenditure on non-network assets	11,574	18,086	14,783	14,683	12,892	12,691	13,158	8,988	10,335	10,015	10,007
21	**Expenditure on assets**	113,233	153,770	149,357	217,500	285,083	303,224	362,602	406,458	468,119	522,967	573,378
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	8,062	17,569	23,997	34,026	31,225	28,322	35,094	48,567	66,368	84,997	107,852
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
27	**Capital expenditure forecast**	105,171	136,200	125,359	183,474	253,858	274,902	327,508	357,891	401,751	437,970	465,526
29	Assets commissioned	94,575	151,200	125,359	183,474	253,858	274,902	327,508	357,891	401,751	437,970	465,526
32		**$000 (in constant prices)**										
33	Consumer connection	22,207	33,012	43,437	55,468	52,581	47,732	62,893	78,671	103,407	128,072	157,383
34	System growth	14,358	25,710	21,290	40,242	75,790	94,176	127,699	148,177	156,191	165,827	170,339
35	Asset replacement and renewal	32,234	36,529	41,032	58,006	78,032	83,708	94,599	93,446	98,260	102,910	100,502
36	Asset relocations	7,560	12,773	10,282	8,557	8,250	11,136	7,180	9,463	9,435	9,415	9,401
37	Reliability, safety and environment:											
38	Quality of supply	14,297	18,144	5,249	22,476	28,933	18,124	12,301	11,145	15,691	12,351	10,767
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	11,003	9,516	9,541	7,578	8,175	7,236	2,823	234	233	233	232
41	**Total reliability, safety and environment**	25,300	27,660	14,791	30,054	37,108	25,360	15,124	11,379	15,924	12,584	10,999
42	**Expenditure on network assets**	101,659	135,684	130,832	192,328	251,762	262,111	307,495	341,137	383,217	418,808	448,624
43	Expenditure on non-network assets	11,574	18,086	14,228	13,641	11,527	11,071	11,198	7,499	8,454	8,032	7,868
44	**Expenditure on assets**	113,233	153,770	145,060	205,969	263,289	273,182	318,693	348,636	391,671	426,840	456,492
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	-	2,206	1,606	3,264	3,373	2,986	2,934	2,561	2,686	2,681	2,412
48	Overhead to underground conversion	7,560	12,773	10,282	8,557	8,250	11,136	7,180	9,463	9,435	9,415	9,401
49	Research and development	1,232	161	161	1,313	1,401	259	258	257	256	256	255
50												

Note: Forecast capex totals are consistent with the totals in prior sections of this AMP. However, Schedule 11a has total capex broken into the Commerce Commission disclosure categories and includes the apportionment of capitalised internal labour. The financial section (Section 9) has the amount of internal capitalised labour shown as a single line item.

Schedule 11a. Report on forecast capital expenditure continued

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2023 – 31 March 2033

52		Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
53	For year ended	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	31 Mar 33
54	**Difference between nominal and constant price forecasts**	**$000**										
55	Consumer connection	-	-	1,242	3,025	4,267	5,176	8,580	12,991	20,121	28,789	40,255
56	System growth	-	-	609	2,195	6,150	10,212	17,421	24,469	30,392	37,276	43,568
57	Asset replacement and renewal	-	-	1,174	3,164	6,332	9,077	12,906	15,431	19,120	23,133	25,706
58	Asset relocations	-	-	294	467	669	1,207	979	1,563	1,836	2,116	2,405
59	Reliability, safety and environment:											
60	Quality of supply	-	-	150	1,226	2,348	1,965	1,678	1,840	3,053	2,776	2,754
61	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
62	Other reliability, safety and environment	-	-	273	413	663	785	385	39	45	52	59
63	**Total reliability, safety and environment**	-	-	423	1,639	3,011	2,750	2,063	1,879	3,099	2,829	2,813
64	**Expenditure on network assets**	-	-	3,742	10,489	20,429	28,422	41,950	56,333	74,568	94,144	114,747
65	Expenditure on non-network assets	-	-	555	1,042	1,365	1,620	1,960	1,489	1,881	1,983	2,139
66	**Expenditure on assets**	-	-	4,297	11,531	21,794	30,042	43,910	57,822	76,449	96,127	116,886
73	**11a(ii): Consumer Connection**											
74	*Consumer types defined by EDB (see note)*	**$000 (in constant prices)**										
76	General Connections	9,904	9,676	9,142	9,242	9,342	9,370					
77	Large Customers	4,259	10,434	23,540	35,345	32,506	26,961					
78	Subdivisions	4,245	4,838	4,302	4,579	4,505	4,146					
79	Switchgear	714	2,688	2,151	2,101	2,076	2,591					
80	Transformers	3,085	5,376	4,302	4,201	4,152	4,664					
81	**Consumer connection expenditure**	22,207	33,012	43,437	55,468	52,581	47,732					
82	*less* Capital contributions funding consumer connections	2,974	6,985	14,716	24,980	21,889	16,442					
83	**Consumer connection less capital contributions**	19,232	26,027	28,721	30,488	30,693	31,290					
84	**11a(iii): System Growth**											
85	Subtransmission	8,071	5,279	5,687	5,151	10,287	7,696					
86	Zone substations	2,137	9,735	7,494	8,486	8,656	17,334					
87	Distribution and LV lines	549	1,107	2,652	8,286	13,882	18,228					
88	Distribution and LV cables	1,415	9,374	3,520	7,684	15,119	17,652					
89	Distribution substations and transformers	-	-	861	2,392	12,119	14,977					
90	Distribution switchgear	464	-	861	2,971	12,582	14,977					
91	Other network assets	1,723	215	215	5,272	3,145	3,311					
92	**System growth expenditure**	14,358	25,710	21,290	40,242	75,790	94,176					
93	*less* Capital contributions funding system growth	-	-	-	-	-	-					
94	**System growth less capital contributions**	14,358	25,710	21,290	40,242	75,790	94,176					
95												

Note: Our capex budgets for new connections are broken down into asset types rather than consumer types and therefore the consumer type definitions in this schedule differ from Schedule 12c(i).

Schedule 11a. Report on forecast capital expenditure continued

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2023 – 31 March 2033

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
97	For year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
98	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
99	Subtransmission	1,422	1,281	1,369	1,112	4,586	5,113
100	Zone substations	7,969	6,333	8,176	13,678	13,935	12,102
101	Distribution and LV lines	6,577	13,300	17,947	23,224	37,220	38,840
102	Distribution and LV cables	817	838	949	2,155	2,131	4,261
103	Distribution substations and transformers	2,759	2,608	2,280	2,638	4,529	5,152
104	Distribution switchgear	7,719	7,684	6,695	11,356	13,912	14,786
105	Other network assets	4,970	4,484	3,616	3,844	1,718	3,454
106	**Asset replacement and renewal expenditure**	32,234	36,529	41,032	58,006	78,032	83,708
107	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
108	**Asset replacement and renewal less capital contributions**	32,234	36,529	41,032	58,006	78,032	83,708
112	**11a(v): Asset Relocations**						
113	*Project or programme*	**$000 (in constant prices)**					
114	NZTA	993	3,849	1,936	2,626	2,076	2,073
115	Christchurch City Council	1,308	5,741	5,162	2,773	2,491	2,488
116	Selwyn Disrtict Council	175	1,032	1,032	1,059	1,607	4,502
117	Developer / 3rd party	5,085	2,150	2,151	2,101	2,076	2,073
118		-	-	-	-	-	-
120	All other projects or programmes – asset relocations						
121	**Asset relocations expenditure**	7,560	12,773	10,282	8,557	8,250	11,136
122	*less* Capital contributions funding asset relocations	5,087	10,584	8,614	7,286	6,993	9,109
123	**Asset relocations less capital contributions**	2,473	2,188	1,668	1,271	1,257	2,027
127	**11a(vi): Quality of Supply**						
128	*Project or programme*	**$000 (in constant prices)**					
129	Comms associated with line switches	223	66	66	279	276	110
130	Northern Christchurch	-	-	-	537	13,634	8,638
131	Region A 66kV subtransmission resilience	12,842	16,645	3,750	19,798	14,453	9,375
132	LV monitoring	1,232	1,433	1,433	1,400	-	-
133	Battery Trials	-	-	-	462	571	-
135	All other projects or programmes – quality of supply						
136	**Quality of supply expenditure**	14,297	18,144	5,249	22,476	28,933	18,124
137	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
138	**Quality of supply less capital contributions**	14,297	18,144	5,249	22,476	28,933	18,124

Schedule 11a. Report on forecast capital expenditure continued

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2023 – 31 March 2033

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
140							
141	For year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
142	**11a(vii): Legislative and Regulatory**						
143	*Project or programme*	**$000 (in constant prices)**					
144	N/A						
145							
146							
147							
148							
150	All other projects or programmes – legislative and regulatory						
151	**Legislative and regulatory expenditure**	-	-	-	-	-	-
152	*less* Capital contributions funding legislative and regulatory						
153	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
156	**11a(viii): Other Reliability, Safety and Environment**						
157	*Project or programme*	**$000 (in constant prices)**					
158	Substation security upgrade (cardax)	-	354	774	756	748	-
159	LV ties replacement with Krone	255	244	244	239	236	236
160	Supply Fuse Relocation Programme	10,748	8,226	8,227	5,023	5,650	6,601
	Tower lines	-	693	-	-	-	-
161	OT Review	-	-	296	404	400	399
162	Trialling of resilience options	-	-	-	1,155	1,142	-
164	All other projects or programmes – reliability, safety and environment						
165	**Other reliability, safety and environment expenditure**	11,003	9,516	9,541	7,578	8,175	7,236
166	*less* Capital contributions funding reliability, safety and environment						
167	**Other reliability, safety and environment less capital contributions**	11,003	9,516	9,541	7,578	8,175	7,236
171	**11a(ix): Non-Network Assets**						
172	**Routine expenditure**						
173	*Project or programme*	**$000 (in constant prices)**					
174	Plant and vehicles	1,365	1,129	949	898	840	1,606
175	Information technology	8,757	14,926	12,439	11,953	9,597	8,665
176	Corporate land and buildings	290	640	275	275	275	275
177	Tools and equipment	1,162	1,391	565	515	815	525
178		-	-	-	-	-	-
180	All other projects or programmes – routine expenditure	-	-	-	-	-	-
181	**Routine expenditure**	11,574	18,086	14,228	13,641	11,527	11,071
182	**Atypical expenditure**						
183	*Project or programme*						
184	N/A						
185							
186							
187							
188							
190	All other projects – atypical expenditure						
191	**Atypical expenditure**	-	-	-	-	-	-
193	**Expenditure on non-network assets**	11,574	18,086	14,228	13,641	11,527	11,071

Schedule 11b. Report on forecast operational expenditure

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2023 – 31 March 2033

7		Current year	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 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	31 Mar 33
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	7,493	9,634	9,898	10,144	10,668	10,915	11,168	11,426	12,297	12,582	12,874
11	Vegetation management	5,024	4,455	4,765	6,586	8,291	11,310	12,729	14,208	15,749	16,114	16,487
12	Routine and corrective maintenance and inspection	15,457	14,316	15,773	26,224	28,852	31,460	34,034	36,819	40,250	41,686	44,506
13	Asset replacement and renewal	2,401	381	2,179	5,391	4,701	3,263	2,991	3,061	3,132	3,204	3,278
14	**Network Opex**	30,375	28,786	32,616	48,345	52,513	56,948	60,922	65,515	71,427	73,586	77,145
15	System operations and network support	18,246	20,683	23,196	27,356	29,491	33,154	38,209	37,656	41,237	46,179	51,464
16	Business support	20,254	28,716	29,930	35,453	37,979	43,495	49,581	56,832	64,220	72,627	81,416
17	**Non-network opex**	38,500	49,399	53,126	62,809	67,470	76,649	87,790	94,488	105,457	118,806	132,880
18	**Operational expenditure**	68,875	78,184	85,742	111,154	119,983	133,597	148,712	160,003	176,884	192,392	210,025
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	7,493	9,634	9,654	9,671	9,940	9,940	9,940	9,940	10,455	10,455	10,455
23	Vegetation management	5,024	4,455	4,648	6,278	7,725	10,300	11,330	12,360	13,390	13,390	13,390
24	Routine and corrective maintenance and inspection	15,457	14,316	15,384	24,999	26,883	28,649	30,292	32,030	34,221	34,640	36,145
25	Asset replacement and renewal	2,401	381	2,126	5,139	4,381	2,972	2,663	2,663	2,663	2,663	2,663
26	**Network opex**	30,375	28,786	31,812	46,087	48,929	51,861	54,225	56,993	60,729	61,148	62,653
27	System operations and network support	18,246	20,683	22,257	25,465	26,557	29,159	32,901	31,780	34,139	37,526	41,036
28	Business support	20,254	28,716	28,716	33,098	34,399	38,483	42,980	48,336	53,580	59,448	65,356
29	**Non-network opex**	38,500	49,399	50,973	58,563	60,956	67,642	75,881	80,116	87,719	96,974	106,392
30	**Operational expenditure**	68,875	78,184	82,784	104,650	109,885	119,503	130,106	137,109	148,448	158,121	169,045
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of energy losses	-	705	1,369	2,143	3,705	3,815	3,650	1,588	1,368	1,368	1,368
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	1,070	1,185	3,195	3,002	1,627	1,985	1,627	1,185	1,185	1,185
36	Insurance	2,879	3,133	3,294	3,577	3,987	4,669	5,440	6,278	7,181	8,155	9,185
38	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	-	-	244	474	728	975	1,228	1,486	1,842	2,127	2,418
44	Vegetation management	-	-	118	308	566	1,010	1,399	1,848	2,359	2,724	3,097
45	Routine and corrective maintenance and inspection	-	-	389	1,225	1,969	2,810	3,741	4,789	6,028	7,046	8,361
46	Asset replacement and renewal	-	-	54	252	321	291	329	398	469	542	616
47	**Network Opex**	-	-	805	2,258	3,584	5,087	6,697	8,522	10,698	12,438	14,493
48	System operations and network support	-	-	939	1,891	2,934	3,995	5,308	5,876	7,098	8,653	10,428
49	Business support	-	-	1,214	2,355	3,580	5,012	6,601	8,496	10,640	13,179	16,060
50	**Non-network opex**	-	-	2,153	4,246	6,514	9,007	11,909	14,372	17,738	21,832	26,488
51	**Operational expenditure**	-	-	2,958	6,504	10,098	14,094	18,606	22,894	28,436	34,270	40,981

Schedule 12a Report on asset condition

					Asset condition at start of planning period (percentage of units by grade)							
7												
8					H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset to be replaced in next 5 years
9	Voltage	Asset category	Asset class	Units								
10	All	Overhead Line	Concrete poles / steel structure	No.	0.17%	0.49%	25.28%	49.53%	24.53%	-	3	0.67%
11	All	Overhead Line	Wood poles	No.	4.46%	0.55%	19.35%	18.90%	56.74%	-	3	14.07%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	13.78%	50.35%	35.88%	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	100.00%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	37.54%	61.90%	0.56%	-	3	13.00%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	100.00%	-	-	3	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	7.32%	36.59%	35.37%	20.73%	-	3	6.10%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100.00%	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	7.41%	40.74%	44.44%	7.41%	-	3	77.80%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	60.66%	9.84%	29.51%	-	3	59.02%
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	6.84%	2.56%	90.60%	-	4	5.98%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	27.05%	3.60%	69.35%	-	4	18.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	

Schedule 12a Report on asset condition continued

					Asset condition at start of planning period (percentage of units by grade)							
36												
37					H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset to be replaced in next 5 years
38	Voltage	Asset category	Asset class	Units								
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	9.52%	45.24%	45.24%	-	3	2.40%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	8.97%	37.61%	53.42%	-	3	9.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	-	-	14.69%	25.38%	59.93%	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	0.28%	1.69%	98.03%	-	1	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	28.67%	46.79%	23.83%	0.72%	1	-
45	HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) – reclosers and sec	No.	-	-	-	22.67%	77.33%	-	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	55.07%	7.53%	37.40%	-	4	25.75%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	4.87%	9.89%	53.46%	31.78%	-	2	7.52%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) – except RMU	No.	-	-	-	-	-	-	N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	14.73%	21.97%	62.49%	0.81%	4	7.23%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.05%	0.85%	13.64%	23.18%	62.28%	-	3	5.53%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	22.65%	20.65%	56.70%	-	3	5.55%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	26.67%	-	73.33%	-	3	13.33%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.20%	0.66%	17.74%	42.30%	39.10%	-	3	2.42%
55	LV	LV Line	LV OH Conductor	km	-	0.30%	15.07%	56.23%	28.17%	0.23%	3	-
56	LV	LV Cable	LV UG Cable	km	-	-	0.39%	17.86%	81.75%	-	1	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km						100.00%	1	-
58	LV	Connections	OH/UG consumer service connections	No.			5.00%	85.00%	10.00%		1	5.00%
59	All	Protection	Protection relays (electromechanical, solid state)	No.	-	-	24.35%	18.69%	56.96%	-	3	16.88%
60	All	SCADA and communications	SCADA and comms equipment operating as a single system	Lot	7.00%	3.00%	13.00%	35.00%	42.00%	-	2	66.79%
61	All	Capacitor Banks	Capacitors including controls	No.					100.00%		2	-
62	All	Load Control	Centralised plant	Lot	-	9.52%	59.52%	23.81%	7.14%	-	3	66.67%
63	All	Load Control	Relays	No.						100.00%	1	-
64	All	Civils	Cable Tunnels	km								

Schedule 12b Report on forecast capacity

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	Addington 11kV #1	18	40	N-1	18	45%	40	52%	No constraint within +5 years	
10	Addington 11kV #2	22	30	N-1	22	72%	30	73%	No constraint within +5 years	
11	Armagh	17	40	N-1	17	43%	40	57%	No constraint within +5 years	
12	Barnett Park	10	15	N	10	66%	15	64%	No constraint within +5 years	Single 66kV line and 23MVA transformer backed up by 11kV but limited to 15MVA by compliance with security of supply standard
13	Belfast	-	15	N	15	-	15	72%	No constraint within +5 years	Single 66kV line and 48MVA transformer backed up by 11kV but limited to 15MVA by compliance with security of supply standard
14	Bromley	34	47	N-1	34	71%	48	71%	No constraint within +5 years	
15	Dallington	28	40	N-1	28	70%	40	69%	No constraint within +5 years	
16	Fendalton	36	40	N-1	36	90%	40	88%	No constraint within +5 years	
17	Halswell	19	23	N-1	19	83%	46	54%	No constraint within +5 years	Install 3rd transformer when needed
18	Hawthornden	35	40	N-1	35	87%	40	87%	No constraint within +5 years	
19	Heathcote	25	40	N-1	25	63%	40	63%	No constraint within +5 years	
20	Hoon Hay	32	40	N-1	32	79%	40	80%	No constraint within +5 years	
21	Hornby	15	20	N-1	15	75%	20	79%	No constraint within +5 years	
22	Ilam	8	11	N-1	8	75%	11	72%	No constraint within +5 years	
23	Lancaster	21	40	N-1	21	52%	40	55%	No constraint within +5 years	
24	McFaddens	36	40	N-1	36	89%	40	88%	No constraint within +5 years	
25	Middleton	27	40	N-1	27	67%	40	70%	No constraint within +5 years	
26	Milton	39	40	N-1	39	97%	40	97%	No constraint within +5 years	Load transfer to Addington when needed
27	Moffett	15	23	N-1	15	63%	23	67%	No constraint within +5 years	
	Oxford Tuam	17	40	N-1	17	42%	40	44%	No constraint within +5 years	
	Papanui	46	48	N-1	46	96%	48	86%	No constraint within +5 years	
	Prebbleton	8	15	N	8	52%	15	61%	No constraint within +5 years	
	Rawhiti	30	40	N-1	30	75%	40	73%	No constraint within +5 years	
	Shands	13	20	N-1	13	66%	20	92%	No constraint within +5 years	
	Sockburn	26	39	N-1	26	65%	39	66%	No constraint within +5 years	
	Waimakariri	20	40	N-1	20	50%	40	54%	No constraint within +5 years	
	Annat	4	-	N	3	-	-	-	No constraint within +5 years	
	Bankside	4	-	N	3	-	-	-	No constraint within +5 years	
	Brookside 66kV	8	-	N	5	-	-	-	No constraint within +5 years	
	Darfield	5	-	N	4	-	-	-	No constraint within +5 years	
	Diamond Harbour	3	-	N	3	-	-	-	No constraint within +5 years	
	Dunsandel	16	23	N-1	11	70%	23	99%	Transformer	Add 3rd transformer when needed
	Duvauchelle	4	8	N-1	4	58%	8	56%	No constraint within +5 years	

Schedule 12b Report on forecast capacity continued

12b(i): System Growth – Zone Substations

	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
	Greendale	6	-	N	4	-	-	-	No constraint within +5 years	
	Highfield	8	-	N	6	-	-	-	Transformer	Transfer to Norwood when Burnham zone substation is built
	Hills	7	-	N	5	-	-	-	No constraint within +5 years	
	Hororata	8	-	N	5	-	-	-	No constraint within +5 years	
	Killinchy	9	-	N	6	-	-	-	No constraint within +5 years	
	Kimberley	14	23	N-1	10	61%	23	63%	No constraint within +5 years	
	Larcomb	19	23	N-1	13	82%	23	80%	No constraint within +5 years	
	Lincoln	10	10	N-1	7	100%	10	109%	Transformer	Constraint to be resolved by transfers to Springston zone substation or non network alternative
	Little River	1	-	N	1	-	-	-	No constraint within +5 years	
	Motukarara	3	8	N-1	3	41%	8	44%	No constraint within +5 years	
	Rolleston	11	10	N-1	8	109%	23	61%	Transformer	To be replaced by new Burnham zone sub
	Springston 66/11kV	8	-	N	5	-	23	49%	Transformer	Staged upgrade to 2 x 23MVA transformers
	Te Pirita	9	-	N	6	-	-	-	No constraint within +5 years	
28	Weedons	14	23	N-1	10	61%	23	88%	No constraint within +5 years	

Schedule 12c Report on forecast network demand

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*	Number of connections					
9		*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	For year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
11	*Consumer types defined by EDB**						
12	Streetlighting	7	20	15	15	15	15
13	General	7,166	6,935	5,200	5,250	5,295	5,355
14	Irrigation	5	10	10	10	10	10
15	Major Customer	17	25	20	20	20	20
16	Large Capacity	-	-	-	-	-	-
17	**Connections total**	7,195	6,990	5,245	5,295	5,340	5,400
18							
22	**Distributed generation**						
23	Number of connections	1,081	1,225	1,000	1,000	1,000	1,000
24	Capacity of distributed generation installed in year (MVA)	7	11	20	122	70	10
25	**12c(ii) System Demand**						
26							
27	**Maximum coincident system demand (MW)**						
28	GXP demand	659	679	694	709	723	738
29	*plus* Distributed generation output at HV and above	2	2	2	2	2	2
30	**Maximum coincident system demand**	660	680	696	711	724	740
31	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
32	**Demand on system for supply to consumers' connection points**	660	680	696	711	724	740
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	3,442	3,483	3,525	3,567	3,610	3,653
35	*less* Electricity exports to GXPs	-	-	-	-	-	-
36	*plus* Electricity supplied from distributed generation	16	18	19	21	22	24
37	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
38	**Electricity entering system for supply to ICPs**	3,458	3,501	3,544	3,588	3,632	3,677
39	*less* Total energy delivered to ICPs	3,321	3,362	3,403	3,445	3,487	3,530
40	**Losses**	137	139	141	143	145	147
41							
42	**Load factor**	60%	59%	58%	58%	57%	57%
43	**Loss ratio**	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%

Schedule 12d Report forecast interruptions and duration

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
9	For year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
10	**SAIDI**						
11	Class B (planned interruptions on the network)	13.2	13.2	13.2	13.2	13.2	13.2
12	Class C (unplanned interruptions on the network)	66.5	66.5	66.5	66.5	66.5	66.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.15	0.15	0.15	0.15	0.15	0.15
15	Class C (unplanned interruptions on the network)	0.84	0.84	0.84	0.84	0.84	0.84

Schedule 13 Report on asset management maturity

Schedule 13 is laid out with the questions and Orion's maturity level (Score) results on left hand page with the questions repeated on the facing page along with the detailed maturity level assessment criteria. See Section 2.9 for information regarding the assessment process.

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3.5	The AM Policy document clearly reflects the drivers of Orion NZ's two main stakeholders (both local councils), in that they are their to serve the needs of their communities. The Asset Management Policy is embedded into the AMP 2022 in section 2.7. It is clear, concise and brief. It sets the asset management direction for Orion and is easy for people to understand the key aims.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3.5	The Orion NZ Asset Management Strategy is imbedded within the AMP 2022 document in Section 2.8. Orion's Asset Management Strategy has five stated focus areas: 1. Re-imaging the Future Network 2. Customer Inspired 3. Powering the Low Carbon Economy 4. Accelerating Capacity 5. Lead and Grow Orion is currently developing a draft stand-alone AM Strategy document.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the a
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?	3.25	For each of these focus areas, a detailed explanation is provided within section 2.8 of AMP 2019. Each focus area topic has the following specific details documented: • Purpose; • Focus area objectives, and; • Initiatives; AM Strategy remained the same in 2020.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.5	The 2022 AMP sets out Orion's asset management policy, strategy, practices and expenditure forecasts for the next 10 years from 1 April 2022. This current 337 page 2022 AMP document is of a continued very high quality. Orion are planning a rewrite of the 2023 AMP document, with intentions to reduce the number of pages in the next document, if possible.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).
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?	3.5	The current 2022 AMP which covers the Orion NZ updated strategy, practices, programme of work and expenditure forecasts for the next 10 years from 1 April 2021 to 31 March 2031. The last AMP is available throughout the organisation and via their online intranet site.	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3.5	Responsibility for AMP actions and focus is now included in in staff Job Descriptions and Contractors scopes of work. Ongoing training and awareness of the drivers within the latest AMP's continues.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3.5	The 2022 AMP is focused on upcoming and future asset improvement areas. The Orion business organisational structure has changes and the next AMP needs to align more closely with this changed focus and asset delivery outcomes. WSP saw good evidence of the planned changes and the resources now aligned to deliver these changes.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard.
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.5	Orion are continuing to develop and improve their contingency planning and resilience capabilities. During the recent period of the COVID-19 Lockdown Restrictions (Level 4 and 3), Orion NZ managed their response to this situation via their Crisis Management Team (CMT) structure. This enabled the organisation to effectively manage and support all of their staff and key contractors though this unique situation in New Zealand. The network load demands dropped considerably during the level 3 and 4 periods (approximately by 15%) and there was a large reduction in incident due to the lower volumes of vehicles on the road. Many other improvement areas have been noted.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.
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)?	3.75	Orion has recently undertaken a significant organisational structure change, which has a focus on improving their asset information utilisation and a future networks focus. The new Orion Group structure consists of the following key roles, all have some degree of asset related focus: * Chief Executive * GM Future Networks * GM Electricity Networks * GM Purpose and Performance * GM Value Optimisation * GM Energy Networks * GM Growth and Development * GM Data and Digital.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3.75	The current new structure has increase the amount of asset focused resource and significantly improved the resources available for asset information improvement initiatives.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3.75	Over the past few years it is noted that more members of the Orion Integrated Leadership Team (ILT) have increased their awareness and activity in asset management improvement and awareness activities. New members of the ILT appear to be very asset focused and are providing a fresh new approach, in many cases. This combined leadership approach to asset management across the organisation is proving a very effective tool to ensuring an "Asset Management Culture" is imbedded across the organisation, not just within the infrastructure group.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	4	Orion are continuing the improvement process with outsourcing and procurement of asset management processes. We believe that the contractors utilised are a good fit for the goals that Orion is striving to achieve. The implementation of a new initiative to establish a Project Management Office (PMO), consisting of a combination of Orion (Network Infrastructure) and Connectics Network Service Delivery), is well underway. This is a "work in progress" and will be review next year when it should have been completed and it's performance can be assessed. The PMO is expected to streamline many asset related activities and provide an improved focused on network asset services delivery and performance outcomes.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.
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)?	3.75	Orion is assisting core contractor organisations to development entry level staff in roles aligned with Orion's asset management improvement initiatives. During our discussion with Orion, WSP were given a presentations on new training initiatives which Orion and Connectics are developing together. Another Training Academy presentation was delivered to WSP. It is hoped that this new training initiative will continue to lead to other EDB's and generators joining in and developing this industry specific training programmes. Internal Orion core asset competency training is continuing to be successfully implemented and appears to be well resourced and delivered.	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	4	Staff training programs were again discussed. Key competencies are documented in job profiles and assessed during annual performance reviews, where any training requirements are identified, and training plans developed. Competency recording is well managed, with information housed in Orion's PowerOn application, while competency management processes are carefully documented. Staff and contractors are unable to receive work management permits if their required competencies are not up to date within PowerOn.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/ or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities – including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	4	Staff training programs were again discussed. Key competencies are documented in job profiles and assessed during annual performance reviews, where any training requirements are identified, and training plans developed. Competency recording is well managed, with information housed in Orion's PowerOn application, while competency management processes are carefully documented.	A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. Organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.
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?	3.75	Internal and external communications initiatives have been seen to be effective and well delivered. The high praise received from community feedback mechanisms is showing this performance very well.	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3.5	Orion have made significant improvements and updates to many of their asset related document e.g. Asset Management Reports, on various asset topic were updated in the past two years.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities – internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.75	The AMP details the broad range of information and applications in place to support Orion's asset management system. Most basic asset management information, data and systems appear to be appropriate for the asset management requirements of the business. Orion have in the past, chosen "best of breed" (as opposed to an integrated system). They are now moving to a more integrated approach to the asset information portfolio, with dedicated new resources now tasks with this improvement delivery. Considerable improvement in this area is underway and will be reviewed next year.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3.75	Orion's aim is to seamlessly gather, store and package specifically requested field asset information in their Asset Register from various asset and maintenance inspections. Existing applications have been upgraded and new functionality introduced. New asset related applications are now being assessed and trailed. Next year should see many improvements in this area.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3.75	The AMP records the types of asset data held for each asset class. Updated data generally comes from routine compliance inspections listed in the asset maintenance plans as well as specific inspections carried out as required for a particular asset class. More remote access asset data recording is being put in place for staff and contractors.	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/ or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	Orion use Condition Based Risk Management (CBRM) models for the majority of their network assets. These models utilise asset information, engineering knowledge and experience to define, justify and target asset renewal. They provide a proven and industry accepted means of prioritising risk and health to determine optimal level of capex renewals. This CBRM model is now well imbedded and continues to gain improvements. The CBRM model is one of the tools used to inform the Orion decision making for asset replacement.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/ or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/ or procedure(s) as a result of incident investigation(s). Risk registers and assessments.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3	Orion is now developing processes and applications to improve workflow processes to ensure consistency across the business. Asset focused information systems are now improved and more dedicated resources assigned to the technical/asset related information systems. separate from the business IT system and resources.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3.5	Orion NZ continues to set high standards in this area and has a Compliance Manual which outlines the company's legal compliance obligations.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives
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?	3.5	Orion has continued to update their comprehensive suite of standards and specifications for all critical assets, covering all aspects of the asset lifecycle, from engineering through to procurement to ensure consistency in sourcing both equipment and field servicing. The process of contracting out the works programme is well documented. New processes for the PMO are in development. There are design processes and standards for the majority of the work required at the power distribution level. The activities around the creation, acquisition or enhancement of major asset classes are detailed in 22 AMR's	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/ or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3.75	Orion are continuing to update their technical specification in line with modern developments and industry best practice experiences. They have a focus to standardise equipment where possible and to phase out equipment with know issues or risks. Key applications have recently been upgraded and new functionality implemented as required.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/ incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/ or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3.75	Project works and maintenance activities continue to be closely managed by Orion staff to ensure agreed standards are maintained. This work flow is changing with the implementation of the PMO process. Orion have created a new dashboard tool to show asset related information, e.g., condition, performance, expenditure etc. There has also been a significant improvement in the reporting and presenting of public safety related KPI's. The 2022 AMP now contains a lot more asset performance and asset failure trends. This clearly shows where any problem asset areas are and also indicates the improved performance trends resulting from process improvements.	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	Major failures and incidents are investigated on a case by case basis and escalated to senior management for review. There has been changes to the amount of Orion resources currently available to undertake these investigations, both from a asset failure situation and from a health and safety situation. Unplanned outages are reviewed with respect to the root cause and action taken in the field. An Asset Health Index for major asset groups is updated annually. More effort is currently going into the quality and accuracy of this data. All latest updated AMR's include information on a bowtie diagram to assist with a visual representation of the most likely causes of asset failure for a specific asset type, and the associated consequences of the failure. This type of awareness reinforcement is an excellent way to build this area of asset management within the workforce.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Over the past year there has been a continued focus on undertaking more audits of processes, by both internal and external parties. Experienced internal staff have been used to target business and asset areas where potential risks have been identified. From these audits, actions have been raised, approved and improvements implemented, in many cases.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3.5	Improvements in the monitoring and reporting of planned asset maintenance work activities is underway to look to provide improved asset data for future asset reliability analysis. The current process for monitoring maintenance work activities is being mapped out and gaps identified. Promapp may be used to assist this process.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/ authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.25	All documents are reviewed and updated at least annually. Improvement opportunities are investigated and future funded as appropriate. This planned approach helps to keep costs under control.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3.25	Orion encourages its staff to attend industry events and seek out new innovations with suppliers and peer organisations. They are looking at areas such as software applications, SF6 free switchgear, Control Centre system upgrades and alarm rationalisation project, just to name a few. The new org structure will encourage this learning and improving even more, especially for the Future Networks team.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Appendix G Mandatory explanatory notes on forecast information

Company name: Orion NZ Ltd

For year ended: 31 March 2024

Schedule 14a Mandatory explanatory notes on forecast information

Box 1: Comment on the difference between nominal and constant price capital expenditure forecasts

In our AMP we have disclosed our:

- constant price (real) opex and capex forecasts
- nominal opex and capex forecasts for the ten years FY24 to FY33 inclusive.

In escalating our real forecasts to nominal forecasts, we have:

- split our forecast opex and capex into a number of groups
- forecast an escalation index for each group that represents a reasonable proxy for forecast movements in unit costs for each group
- applied the forecast escalation indices for the ten-year forecast period.

We applied forecast opex and capex escalators as follows:

- network labour – NZIER labour index forecasts to FY27, extrapolated by management to FY33
- non-network labour – NZIER forecasts to FY27, extrapolated by management to FY33
- other – NZIER producer price index (PPI) forecasts to FY27, extrapolated by management to FY33.

Box 2: Comment on the difference between nominal and constant price operational expenditure forecasts

- Please refer to Box 1 above.

Appendix H Certificate for year-beginning disclosures

Schedule 17. Certificate for year-beginning disclosures

We, Paul Munro and Mike Sang, being directors of Orion New Zealand Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of Orion New Zealand Limited prepared for the purposes of clauses 2.6.1 and 2.6.6 of the Electricity Distribution 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 Orion New Zealand's corporate vision and strategy and are documented in retained records.

Director	17 March 2023 Date
Director	17 March 2023 Date

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