Orion New Zealand Limited
Asset Management Plan

Asset Management Plan 2021

Cover: Oxford Lane in Christchurch's central city, powered by new infrastructure installed by Orion.

This Asset Management Plan is our roadmap for delivering on our commitment to 210,000 customers in central Canterbury to provide one of the most safe, reliable and resilient electricity networks in New Zealand – one that's ready for the future.

It is an exhilarating period in our industry's history. New technologies, changing customer expectations and local and international decarbonisation efforts are resulting in the energy sector facing more change than it has experienced over the last 50 years.

To give our customers confidence in how Orion is meeting the promise of this new era, we share our new Group Strategy and the challenges we have set ourselves to deliver on our Group Purpose, the touchstone for this AMP:

To power a cleaner and brighter future for our communities.

These are exciting times at Orion. We are redefining our role in our communities, and taking a broader view of how the Orion Group can contribute to the future prosperity and sustainability of our region, and New Zealand.

David Freeman-Greene
Interim Network Chief Executive

Orion

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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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When considering the content of this AMP, persons should take appropriate expert advice in relation to their own circumstances and must rely solely on their own judgement and expert advice obtained.

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Executive summary

Photo: Janet and David McGimpsey in their warm Bryndwr home, insulated by Community Energy Action with Orion's help.

Introducing our 2021 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 2021.

We share who we are, changes in the environment we operate in, 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 care for and enhance them, and how we support the delivery of this plan.

We continue to operate our network in unprecedented times. Our community depends on us to maintain a safe, reliable and resilient service. Like most businesses, over the past 12 months we've learned to be more flexible and agile in how we operate to keep the power on. At the same time, we've been preparing for a very different future, and taking a fresh look at how we do things and where we can add additional value to our communities. While placing our feet firmly on the ground, the thrill of exploring new opportunities pervades this plan.

Our business is adapting to change

At the heart of what we do is our desire to continue to deliver an electricity service that meets our customers' expectations, at a cost our customers feel is fair and reasonable. To continue to do that well, we must adapt to rapidly evolving customer expectations fueled by new technology that is changing customer behaviour and market forces, and the increasing global realisation that we all need to radically reduce our carbon footprint to secure the future wellbeing of our planet.

We have challenged ourselves to think about what that changed future holds, and how the Orion Group needs to evolve and adapt to remain relevant and proactively harness opportunities in a fast changing energy landscape. Our re-defined Purpose and Group Strategy set a new, dynamic direction for our future contribution to our communities.

Changing demands on our infrastructure as a result of growth in our customer numbers continues to be strongly reflected in this AMP.

We continue to experience steady growth in our residential customer numbers as central Canterbury presents an attractive option for people to make their home, particularly in new housing developments in the Selwyn District and Halswell areas.

What's new, what's changed?

Our Asset Management Plan for 2021 continues the direction we established in 2020. We have made some adjustments to project timings and budgets to reflect the realities of planning in a somewhat fluid environment, and fine-tuning that naturally occurs closer to the time of programme implementation. While our planning in respect of projects and programmes is essentially unchanged, our approach to our future in a dynamically changing environment is significantly changing how we think about our work, and the opportunities presented to us.

> **Our re-defined Purpose and Group Strategy set a new, dynamic direction for our future contribution to our communities.**

Our Asset Management Strategy is underpinned by our Purpose to "Power a cleaner and brighter future for our communities". It reflects how we see our future best serving our community, embodied in our Group Strategy's strategic themes, which are:

Re-imagining the Future Network – ensuring we have intelligent network infrastructure that reflects changes in the energy marketplace and ensures customers can take advantage of future energy opportunities

Customer Inspired – enabling the choices customers make

Lead & Grow – growing our business through strategies and initiatives that leverage our expertise and knowledge within and in areas adjacent to our industry

Accelerating Capability – developing the capability we will need for the future: technical and leadership skills; partnerships with people and organisations inside and outside our industry to drive innovation; and redefining value to our community including our environmental and social impact

Powering the Low Carbon Economy – accelerating electrification, and helping others in our region decarbonise; powering the shift from fossil fuels to a low-carbon climate ready future

Managing new risks

We regularly evaluate our risks and mitigation strategies. COVID-19 brought the risk of a pandemic into sharp focus. As an essential service provider Orion has been acutely conscious of our responsibility to maintain vital power services to our community throughout this pandemic. As the situation evolved, our appreciation of the risks of pandemics on our ability to maintain our service to the community grew.

Consequently, our assessment of Orion's key operational risks has now incorporated pandemics, rated at number five of seven. Throughout this pandemic Orion has implemented new ways of working to ensure we can continue to maintain essential power services to our community, and help in limiting the spread of COVID-19.

In this AMP we have also considered the risks and opportunities presented by climate change for the first time. Also reflecting our focus on this growing risk, in 2020 we published our first annual report in accordance with the guidelines published by the Task Force for Climate-related Disclosures, our *Climate Change Opportunities and Risks for Orion* report. We will continue to improve our understanding of climate effects on our network, and adapt and mitigate risks where appropriate, or reasonably practicable.

Ensuring customer experience and performance meet targets

Seeking out the views of our customers and giving them a voice in our decision making continues to be a focus. 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 our Group Strategy strategic themes.

We measure our customer's assessment of 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 through both independent assessment and against rigorous targets set by the Commerce Commission, and those we set ourselves.

Orion again engaged WSP Opus to undertake an independent assessment based on an Asset Management Maturity Assessment Tool (AMMAT) and Electricity Engineers' Association guidelines. WSP Opus determined that Orion's focus on asset management improvement initiatives, our attention to embedding the right organisational risk management culture, and our focus on continual improvement were reflected in our achievement of an outstanding score of Competent or Excellent in all categories. See Figure 2.9.2.

We also measure our performance against our service targets and for the first time, this year we have developed measures and targets for customer service.

Better informed decisions about our network

We are increasingly using deeper levels of data analysis to inform our asset lifecycle management approach. Drawing data together from a range of sources, this year we introduced a risk matrix that enables us to identify the number of assets most at risk within an asset fleet, and identify what intervention strategy is required. The matrix means we can focus our efforts on those assets within the class that most need replacing to provide the greatest reduction in the overall fleet risk profile.

In this AMP we have also considered the risks and opportunities presented by climate change for the first time.

Planning our network for growth and new technology

Our capital expenditure keeps pace with the growing demand on our network. This growth is both in the number of customers we serve, and energy demand.

To support growth, we have planned six significant programmes of work, see Table 1.1.

We are also investing in readying our network to enable our customers to take advantage of new technologies. An increasing number of customers are thinking about installing solar PV, putting excess solar generation or power stored within a charged battery back into the grid, and considering a move to electric vehicles that are cleaner and cheaper to run. This energy transformation means our customers' usage patterns are becoming more complicated as energy sources become embedded across our distribution network. Our low voltage monitoring programme, see Table 1.1, is an important step towards ensuring our network is ready to help power the future needs of the community.

This AMP builds on the planned maintenance and development of our network set down over the past two years, with minor adjustments to the relative timings of some individual projects.

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For a list of our key capital and maintenance projects and programmes, see Tables 1.1, 1.2 and 1.3 starting on page 15.

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.

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.

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

Gearing up for the future

As our Group Strategy gains momentum, we are changing some of the ways we do things and introducing new roles to deliver on our strategic themes.

Our focus on continually developing our capability as effective asset managers means we are reshaping our approach to works delivery. These refinements will ensure we are able to deliver the projects in this AMP safely, efficiently and to the quality we expect into the future.

The Orion Group is also working with industry partners through an initiative called the Energy Academy to be part of the changes in capability development, to ensure our people are “match fit”.

These organisational changes and other initiatives to support our community’s evolving needs, delivery of the projects in this AMP and our increased focus on preparing for the future will result in a gradual increase in FTEs over the regulatory period.

Financial forecast

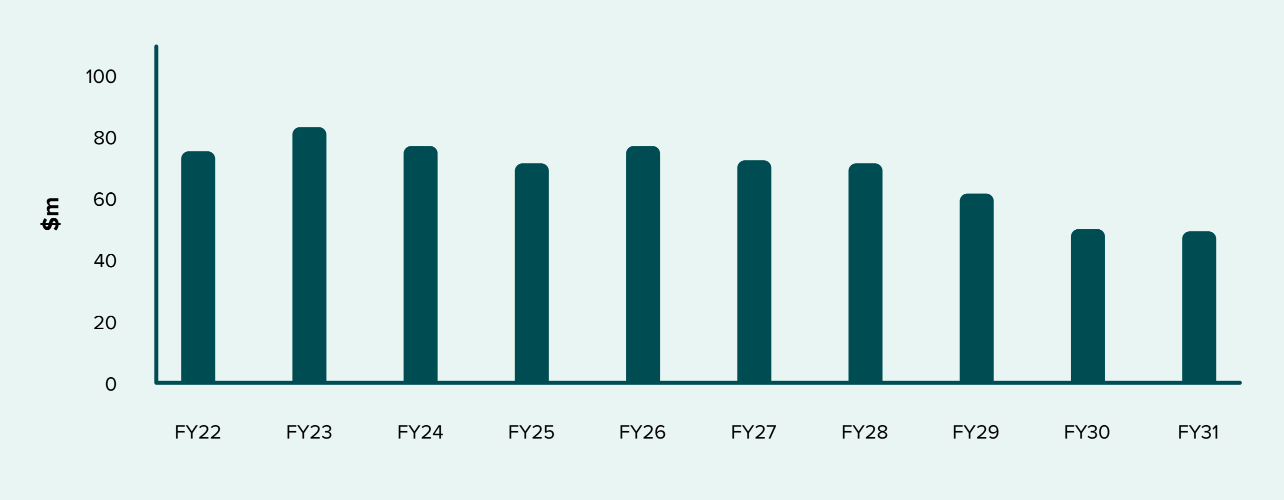
Over the next ten years we are forecasting total capital expenditure of $746m and operational expenditure of $650m. We plan to undertake expenditure wisely, and provide our customers with genuine value for that money.

Capital expenditure

Over the 10 year period covered by this plan, we project a steady level of capital expenditure to meet demand from major industrial customers and steady growth in residential in certain locations. Our capex projections also support maintenance of safety levels and asset condition for asset fleets.

Orion’s six major capital programmes and their drivers over this AMP period are listed in Table 1.1. A list of our capital replacement projects and their drivers over this AMP period can be found in Table 1.2.

Figure 1.1 Total network capex forecast ($000)

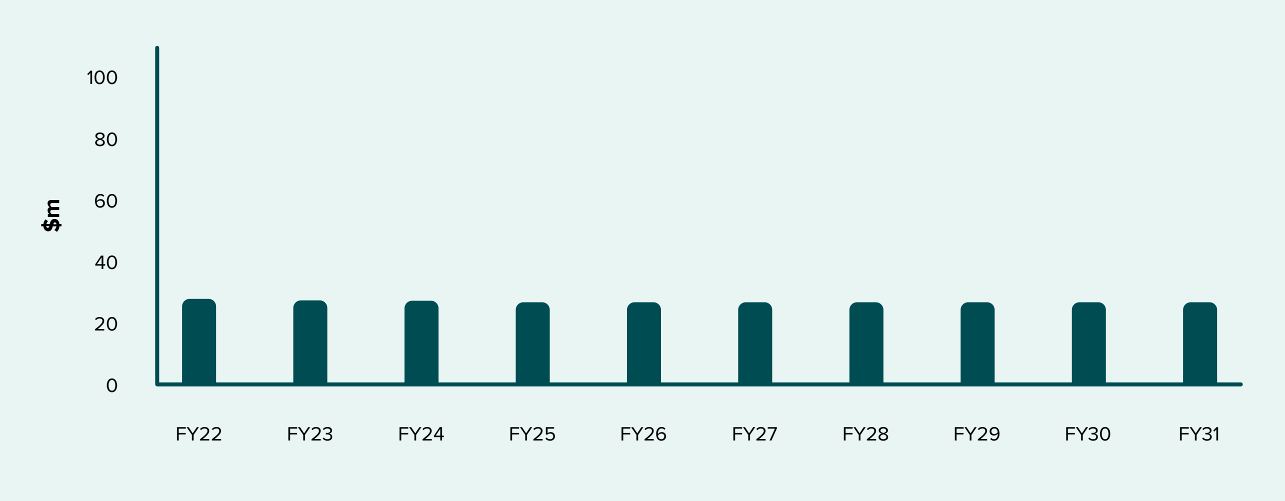


Operational expenditure

Our operating expenditure forecast shows an ongoing steady level of opex into the next 10 year period. We have anticipated increases in labour rates particularly in contract rates with service providers for emergency standby and repair work. Our opex forecast is underpinned by our on-going programme of inspection, testing and monitoring regimes.

Our maintenance projects and their strategic drivers over the AMP period can be found in Table 1.3.

Figure 1.2 Total network opex forecast ($000)



Expenditure changes from 2020 AMP

Compared to last year's AMP, the main changes in network expenditure over this AMP period are:

An increase of $45.7m network capital expenditure due to:

- $21.9m – an increase in major projects capex due to residential and industrial growth as well as changes in timing of projects to meet changes in customer needs
- $13.9m – an increase in asset replacement largely due to new programmes to upgrade LV conductors and replace LV panels. There's also an increase due to refinement of circuit breaker unit cost per job based on recently completed projects
- $3.3m – an increase in connections capex largely due to refinement of cost for distribution transformers
- $6.6m – an increase in asset relocation due to new projects identified by road authorities

An increase of $13.4m network operational expenditure due to:

- $6.5m – an increase in maintenance of the overhead system due to improved pole inspection processes and targeted vegetation trimming projects
- $4.4m – an increase to reflect on more proactive work being carried out during maintenance rounds of our substation assets
- $2m – a slight increase in labour cost for emergency jobs. This increase also reflects provision for asset labelling
- $0.5m – an increase in Network Management Systems to cover maintenance for switching advisor, primary outage restoration tool and LV monitoring functions

Delivering our works programme

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

We are developing and maturing our systems and processes to ensure transparency, rich data for decision making, consistency and adaptability for the future. We are extending our existing distribution management system to support further automation. Our asset management processes, standards, modelling, review and monitoring programmes are among New Zealand's best, as attested to in the 2020 AMMAT assessment, see Figure 2.9.2.

In the following pages, Tables 1.1, 1.2 and 1.3 we provide a list of our key capital and maintenance projects and programmes and their alignment with Orion Group's strategic themes and project drivers.

Table 1.1 Top six network development programmes for FY22 to FY31

		Customer Inspired		**Powering the Low Carbon Economy**	**Re-imagining the Future Network**		**Lead & Grow**				**Accelerating Capability**
Programme or project	**Year(s)**	Customer connections	Asset relocation	Reliability, safety and environment		System growth		Asset replacement and renewal	Reliability, safety and environment	Non-network assets	
Northern Christchurch network	FY22 - 23	🟩✓					🟦✓		🟩✓		
Region B 66kV subtransmission capacity	FY22 - 23						🟦✓		🟩✓		
Region A 66kV subtransmission resilience	FY23 - 31 FY23 - 26			🟩✓				🟦✓	🟩✓		
Lincoln area capacity and resilience improvement	FY28 - 29	🟩✓					🟦✓		🟩✓		
Rolleston area capacity and resiliency	FY22 - 26						🟩✓		🟩✓		
Low voltage monitoring	FY22 - 29			🟩✓		🟦✓			🟦✓		

🟦 Primary drivers 🟩 Secondary drivers

Table 1.2 Capital replacement programmes and their drivers over the next ten years

			Customer Inspired		**Powering the Low Carbon Economy**	**Re-imagining the Future Network**	**Lead & Grow**			**Accelerating Capability**
Asset class	**Programme description**	**Capex forecast $000**	Customer connections	Asset relocation	Reliability, safety and environment		System growth	Asset replacement and renewal	Reliability, safety and environment	Non-network assets
Overhead lines	Ongoing pole and conductor replacement, overhead to underground conversion and line switch replacement	**128,769**						🟩 ✓	🟦 ✓	
Switches	This asset class replacement is driven by condition and risk	**100,508**			🟩 ✓			🟩 ✓	🟦 ✓	
Underground	Replacement of cables and link boxes. It includes the supply fuse relocation programme which removes legacy issues	**49,275**						🟩 ✓	🟦 ✓	
Secondary systems	Work includes relay replacement, radio upgrades and fibre installation between zone substations. Management system enhancement. LV correction equipment upgrade to improve power quality	**39,630**						🟩 ✓	🟦 ✓	
Transformers	Replacement of end of life power and distribution transformers	**16,220**					🟩 ✓	🟩 ✓	🟦 ✓	
Network property	Work includes kiosk and security fence upgrade as well as grounds maintenance	**10,050**						🟩 ✓	🟦 ✓	

🟦 Primary drivers 🟩 Secondary drivers

Table 1.3 Maintenance programmes and their drivers over the next ten years

			Customer Inspired		**Powering the Low Carbon Economy**	**Re-imagining the Future Network**	**Lead & Grow**			**Accelerating Capability**
Asset class	**Programme description**	**Capex forecast $000**	Customer connections	Asset relocation	Reliability, safety and environment		System growth	Asset replacement and renewal	Reliability, safety and environment	Non-network assets
Overhead lines, underground, switches, transformers and secondary systems	Asset monitoring, inspections and maintenance. Response to emergencies and supply interruptions	**217,940**						🟩 ✓	🟦 ✓	
Overhead lines	Vegetation management	**41,720**						🟩 ✓	🟦 ✓	
Overhead lines	Improvements to maintain safety of poles and integrity of overhead components	**8,630**						🟩 ✓	🟦 ✓	
Underground	Monitoring to maintain capacity and security of underground system	**1,250**						🟩 ✓	🟦 ✓	
Power transformers	Refurbish and maintain key components of transformers to maintain or extend asset life	**1,590**					🟩 ✓	🟩 ✓	🟦 ✓	
Network property	Improvements to maintain integrity of property protecting network assets	**950**						🟩 ✓	🟦 ✓	

🟦 Primary drivers 🟩 Secondary drivers

AMP Section summary

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

Section 1: Executive summary

Our 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: About our business

We deliver electricity to more than 210,000 homes and businesses in Christchurch and central Canterbury. In this section we explain how our asset management programme is driven by our Group Strategy, our Asset Management Policy and we set out our project drivers.

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 FY20 and our targets for the planning period.

Section 5: About our network

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: Planning our network

Here we detail our planning criteria, projections for energy demand and growth, our network gap analysis and list our proposed projects. Maximum network demand is the major driver of investment in our network and here we discuss the factors which are driving demand as our region continues to grow. We also discuss how we are preparing for the future and our customers' adoption of new technologies that will impact on network demand and operational management.

Section 7: Managing our assets

Section 7 provides an overview of each of our 18 asset classes; and outlines an assessment of their asset health along with our maintenance and replacement plans for each one.

Section 8: Supporting our business

This section provides an overview of the Orion teams who together, enable our business to function. It outlines the number of people in each team and describes their responsibilities. It also describes organisational changes and other initiatives to support customer growth, expansion of our network, and our increased 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 FY22 to FY31.

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 philosophies, policies and processes that enable us to deliver our works programme and AMP objectives, see Section 10.

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

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About our business

Photo: Keeping the lights on for night training at Foster Park, Rolleston.

Contents

2.1 Purpose of our AMP

Our AMP sets out Orion's asset management practices for its electricity distribution business and how they contribute to the Orion Group Strategy. We update and publish our 10 year AMP in March each year.

In an environment of rapid change and uncertainty, our AMP reflects our best predictions of where we see our network serving our community well in evolving times. We face this uncertainty confident that our people and network have the agility to respond as needed.

We are taking into account these factors:

- continuing growth in customer numbers
- changing customer needs and their desire for more affordable energy
- the increasing impact of climate change
- mounting urgency to decarbonise our economy
- the accelerating pace of change
- the rapid development of new technology that provides customers with more options
- pandemics are here to stay and have changed the way we work, and manage our supply chain
- fluctuations in commodity prices

This plan is also created with the knowledge we have today of our customers' plans, which can change, sometimes rapidly. We work closely with customers to support their needs, adjusting and adapting our planning as needed and possible.

While this AMP looks ahead for the 10 years from 1 April 2021, we are confident of our ability to be flexible, to adapt to changing circumstances and adjust our planning in both the short and long term as needed.

Our main focus is on the next three to five years, with the highest level of certainty in the first year. Beyond three to five years our forecasts are necessarily more indicative as we respond to adjustments in the expectations of our customers and community.

This AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012. These requirements include:

- a summary
- background and objectives
- target service levels
- details of assets covered and lifecycle management plans
- load forecasts, development and maintenance plans
- risk management, including policies, assessment and mitigation
- performance measurement, evaluation and improvement initiatives

A cross reference table showing how our AMP meets the regulatory information disclosure requirements is shown in Appendix B.

Our AMP goes beyond regulatory requirements. It also considers what investments we need to make to support our Purpose and Strategy. We aim to demonstrate responsible stewardship of our electricity distribution network, in the long term interests of our customers, shareholders, electricity retailers, government agencies, service providers, and the wider community.

We aim to optimise the long term costs at each point in the lifecycle of every network asset group to meet target service levels and future demand.

2.2 Our business

We own and operate the electricity distribution infrastructure powering our customers and the community in Christchurch and central Canterbury. Our network is both rural and urban and extends over 8,000 square kilometres across central Canterbury from the Waimakariri in the north to the Rakaia river in the south; from the Canterbury coast to Arthur's Pass. We deliver electricity to more than 210,000 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.

Under economic regulation we are subject to a five-year Default Price-Quality Path for FY21 to FY25.

Rapidly changing technologies and New Zealand's drive for a low carbon future are providing opportunities for our customers to produce, store, and consume electrical energy rather than simply consuming energy provided to them.

These changes are changing the way we and our customers are thinking about electricity, and have the potential to alter the demands on our network assets and the services our customers require. It is vital we enable open access and customer choice while recognising that providing network connected services and backup supply will continue to be used by a large majority of our customers.

Electricity distribution is an essential service that underpins regional, community and economic wellbeing. It also has a critical part to play in New Zealand's transition to a low-carbon economy. Orion is confident it has the agility and capability to continue to serve its customers well in an evolving energy landscape.

2.3 Our local context

Our region is a place of transformation, embracing change and innovation.

We are a passionate advocate for clean energy, and a proactive enabler of those seeking help to reduce their carbon footprint through more efficient use of low carbon energy sources. Our service is vital to the wellbeing and livelihood of the people and businesses in our region. This responsibility drives us to understand more about the impacts of climate change on our operations, so our network and our business can continue to be safe, reliable and resilient. Climate change means central Canterbury is likely to face more severe droughts and more extreme weather events. Warmer summers may change traditional energy consumption patterns. New technologies assisting the transition to a low-carbon economy will also impact our business.

In our first report on the Climate Change Opportunities and Risks for Orion, published in 2020, we provided our community with an understanding of how climate risks and opportunities might impact our business, and what we are doing to prepare for a changed future. We also shared the actions we are taking to contribute to New Zealand's carbon zero 2050 commitment.

The impacts of issues such as climate change, new technology and resource demands mean Orion must play an increasingly significant role in addressing social, environmental and economic issues.

People and businesses continue to be drawn to settle in central Canterbury, and growth in customer numbers has stabilised at around 3,000 per year. Christchurch's central business district continues to see progress with the completion of cornerstone building projects.

Good crisis planning and the flexibility and agility of our people in adapting to radically changed circumstances helps us continue to operate efficiently and support our community during the COVID-19 pandemic.

After a pause while we focused on emergency work during lockdown, by mid 2020 our network maintenance and upgrade programme recommenced in earnest and indications are we will have largely achieved our planned programme of work for the year ending 31 March 2021 with some adjustments to accomodate supply chain issues due to COVID-19.

We know that many people and businesses in our community have been adversely affected by the impact of COVID-19. Though the future may still feel uncertain for many, we continue to be a trusted partner in enabling our region's recovery.

Our **Purpose** is to power a cleaner and brighter future for our communities.

2.4 Our Group Strategy

2.4.1 Our Group Purpose

Orion's Group Purpose is central to all we do, and is the touch stone 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 focussed on helping our community realise its dreams for a future that is new, better, and more sustainable over the long term. Our Group Strategy is changing the shape of Orion's contribution - to use the skills and expertise of the Orion Group to meet the changing needs of our community today and tomorrow.

2.4.2 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 evolve and adapt to remain relevant and proactively harness opportunities in a fast changing energy landscape.

The outcome of this is our Group Strategy. See Figure 2.4.1.

Figure 2.4.1 Group Strategy framework

Our Group Purpose is: ***Powering a cleaner and brighter future for our communities.*** It encapsulates the contribution we want to make to our community's future wellbeing and prosperity.

- **Powering** – coveys our commitment to taking action and reinforces our focus on energy
- **Cleaner** – speaks to our commitment to assisting our region and New Zealand's transition to a low carbon future and being environmentally sustainable
- **Brighter** – reflects our contribution to social and economic prosperity
- **Our communities** – reflects our holistic view that includes our people, our region and New Zealand

Sustainable Development Goals – are a subset of 17 United Nations goals that define global sustainable development priorities and aspirations. We consulted with a variety of our key stakeholders who helped us select the seven goals that were most relevant to Orion, and where we could have the most impact. They provide a common language that enables us to collaborate and form partnerships with other like-minded organisations.

Impacts – we aim to make a clear, measurable impact in these three critical areas

Strategic themes – are the areas we are focussing on to fulfil our Purpose

Our foundation – underpins all that we do; it is critical we continue to perform our core network role exceptionally

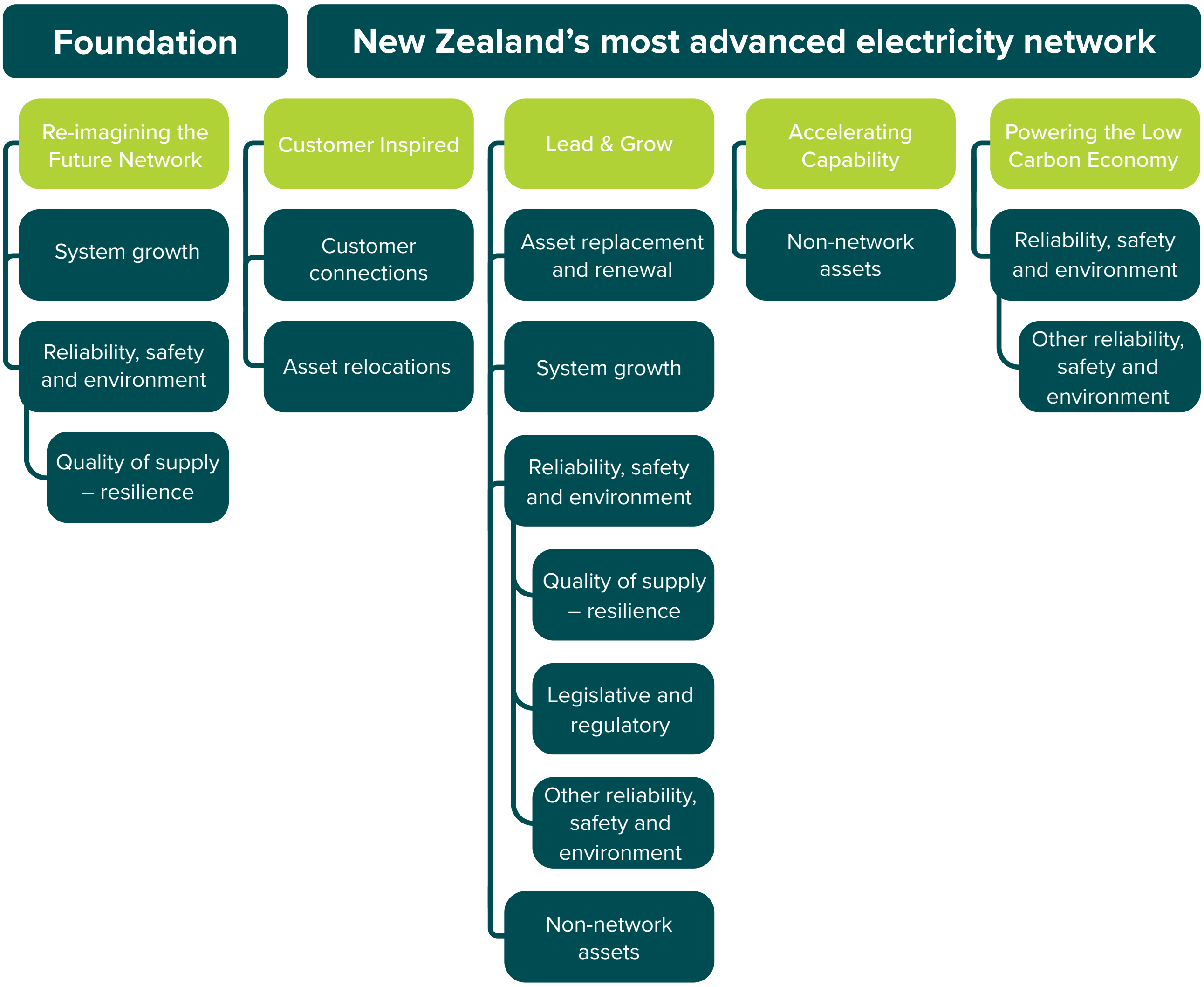
Our enablers – the building blocks that will enable us to achieve our Group Strategy

This AMP delivers on our commitment to operate New Zealand's most advanced electricity network and undertake our core network role to the high standard expected by our customers. It also outlines many new projects and initiatives aligned to our Group's Strategic Themes, with more to come as the Group Strategy gains momentum.

2.4 Our Group Strategy continued

We have aligned our programmes and projects to our foundation and our five strategic themes. In Figure 2.4.2 we show the Commerce Commission's project drivers and how they relate to each strategic theme.

Figure 2.4.2 Orion Group Strategy strategic theme and the related programme and project drivers



2.4.3 Programme and project driver definitions

System growth
Additional investment to maintain current security and/or quality of supply standards due to increased demand and/or generation. Includes SCADA and telecommunications assets.

Customer connections
Customer connection points established and alterations made to an existing customer connection point during the year, and includes both electricity injection and offtake points of connection.

Non-network sssets
Expenditure on non-network assets including: information and technology systems; asset management systems; office buildings and vehicles.

Asset relocations
Expenditure on assets where the primary driver is the need to relocate assets due to third party requests, for example, to allow for road widening. Includes undergrounding.

Reliability, safety and environment

- **Quality of supply - resilience –** expenditure required to meet improved security and/or quality of supply standards. E.g. reducing SAIDI, SAIFI etc.
- **Legislative and regulatory –** expenditure on assets where the primary driver is a new regulatory or legal requirement that results in the creation or modification of network assets.
- **Other reliability, safety and environment –** expenditure to improve network reliability or safety or to mitigate the environmental impacts of the network, but is not included in either of the quality of supply or legislative and regulatory categories.

Asset replacement and renewal
Replacement or renewal of assets to maintain network asset integrity to maintain current security and/or quality of supply standards.

2.5 Asset Management Plan development process

An overview of our AMP development and review process is provided in Figure 2.5.1. This process is robust and includes challenge from peers, our Leadership Team and Board.

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

Our AMP is a collaborative effort that combines and leverages the talents, skills and experience of our people. The development of our final work plans are 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 infrastructure managers, 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, including media.

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

During 2020 our board reviewed and approved, in principle, business cases for the next stages of these two projects:

- **11kV works in conjunction with the new substation at Belfast** proposed for the period FY22. More detail on these projects can be found in Table 6.6.1 and Table 6.6.2.
- a **new GXP at Norwood** and associated interconnection work across a number of stages proposed for the period FY21 to FY25. More detail on these projects can be found in Figure 6.6.2 and Table 6.6.3.

Each year we aim to improve our AMP to take advantage of customer insights, new information and new technology.

Also during 2020 our board reviewed two high value Asset Management Reports which discuss and set out the strategy for our assets:

- 400V overhead lines. See Section 7.6
- subtransmission towers due to an opex step change. See Section 7.4

As part of our internal audit programme, findings from the Deloitte 2019 audit have enabled us to focus the criteria we use for evaluating and prioritising projects.

As a result of this audit we further refined our internal processes around economic justification, work planning and prioritisation during 2020.

Based on our current approach we anticipate that during FY22 and FY23 the board will review and / or approve four or more business cases and a minimum of four AMRs.

2.5.1 Statement of Intent

This AMP is guided by our Group Strategy, and is consistent with and supports both our Statement of Intent (SOI) and our Business Plan. The scope of our Group Strategy is wider than our AMP.

Our SOI sets out our key roles, the scope of our governance and relationship to shareholders, and our intentions and performance targets for the next three financial years.

In accordance with Section 39 of the Energy Companies Act, we submit a draft SOI to our shareholders prior to each financial year. After carefully considering shareholders' comments on the draft, the Orion board approves our final SOI. Our approved SOI is then sent to our shareholders and is published on our website.

2.5 Asset Management Plan development process continued

Figure 2.5.1 AMP development process

AMP development process

	Our board	Our leadership	Our customers
Strategy Ensure alignment of strategy across SOI, Business Plan, Asset Management Policy and Strategy	Board approves Group Strategy, SOI, and 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
Continual improvement and monitoring Track performance, report and make operational adjustments to improve efficiency	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	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

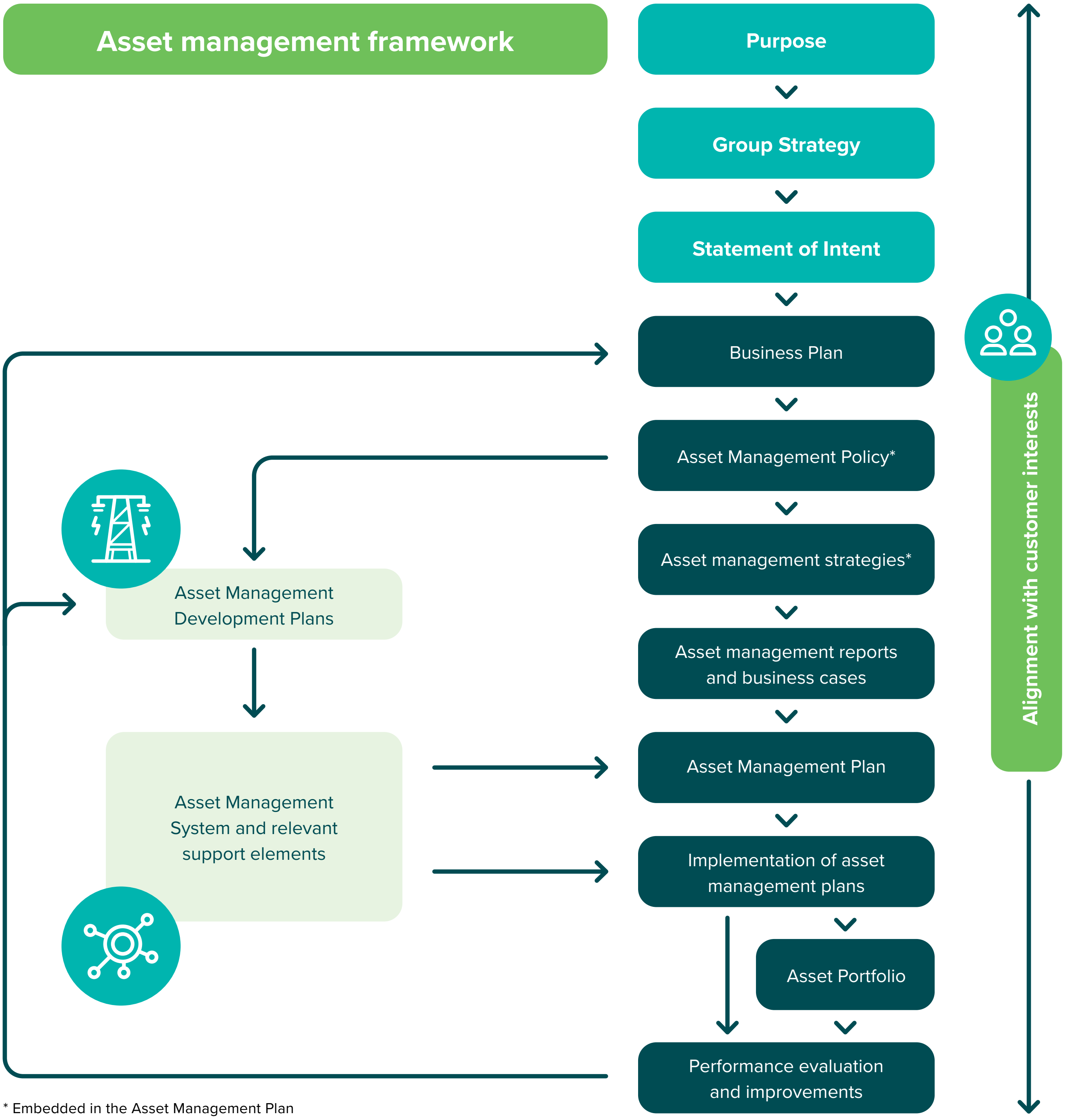
2.6 Asset management framework

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

- our decisions, plans, and actions are in alignment with our Purpose, our Group Strategy and the goals, objectives and targets of our SOI and 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 2.6.1 is essentially a hierarchy of documents and processes that provide for clarity of purpose and alignment from our Purpose, Group Strategy, Statement of Intent and Business Plan to our investment and operational decisions and actions.

Figure 2.6.1 Orion's asset management framework



* Embedded in the Asset Management Plan

2.7 Asset management policy

Our asset management policy is to use good asset management practices to deliver on our Purpose, Group Strategy and to consistently deliver a safe, reliable, resilient and sustainable electricity service that meets our customers' needs. We are committed to regular reviews of our processes and systems to ensure continual improvement.

We listen to our customers and stakeholders with the aim to:

- enable customer choice
- lead a just transition to a low carbon economy
- ensure our customers can access the benefits and opportunities that new technology can provide
- provide a safe, resilient, reliable and sustainable electricity service
- keep costs down and provide value for money for our network investments
- meet the long-term interests of our customers and shareholders
- embed safe working practices – for our employees, service providers and the public
- provide excellent customer service
- recruit, develop and retain great people
- build effective relationships with relevant stakeholders – including customers
- comply with relevant regulatory requirements

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 asset management practices – how we propose to maintain and replace our key network assets over time
- our network development – how we propose to meet changing demands on our network over time
- how we propose to deliver our plan
- our risk management approach
- our ten-year expenditure forecasts – capital and operating
- our evaluation of our past performance
- how we can enhance our core activities with improved field data

Our infrastructure management team reviews our AMP annually and reviews planned projects and expenditure forecasts. Our leadership team provides a further review before it is presented to the board for approval.

Our asset management policy is to use good asset management practices to consistently deliver a safe, reliable, resilient and sustainable electricity service that meets our customers' needs.

2.8 Asset management strategy

Our asset management strategy reflects the external environment in which our network operates. Community use of electricity and customer expectations are changing. Community dependence on electricity is increasing with the adoption of new technology, electrification of the transport system and the global movement to a low carbon economy.

Our asset management objectives are based on our aspiration to be New Zealand's most advanced electricity network and our five strategic themes. See Figure 2.4.1.

It ensures our decisions, plans and actions are consistent with our Purpose, and our actions work efficiently and effectively towards achieving our Group Strategy and Business Plan as well as our Asset Management Policy objectives.

An output of this asset management strategy is a suite of technical strategies that define our technical approach for developing actionable projects and plans. Examples include our subtransmission architecture review which defines our approach for developing the network and asset management reports which define our approach to managing the lifecycle of existing assets. Another output of this asset management strategy is an evolving asset management development plan which complements our Group Strategy.

2.9 Asset Management Maturity Assessment Tool (AMMAT)

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 Asset Management Maturity Assessment Tool (AMMAT).

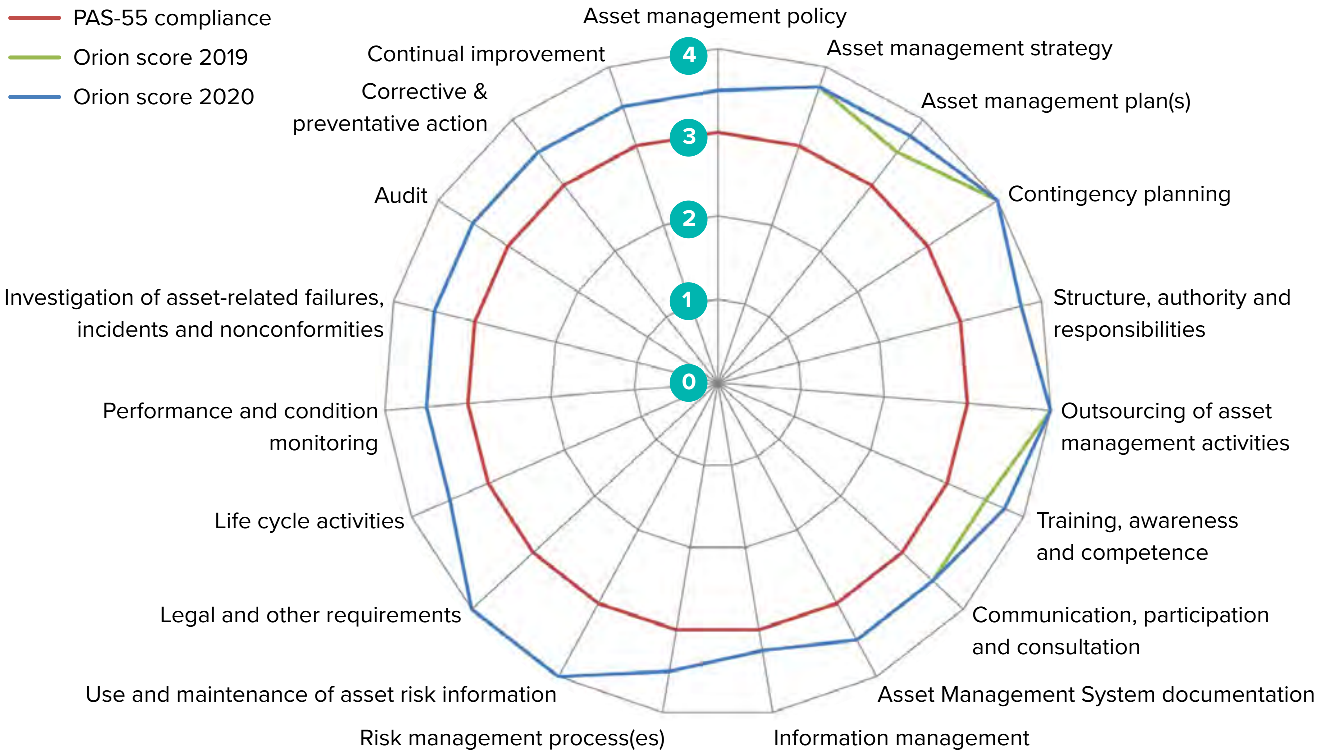
The tool provides a clear, detailed and consistent approach to assessing the maturity of an EDBs asset management. Assessment is undertaken based on the responses, both verbal and backed by evidence, to a set of 31 questions selected by the Commerce Commission from the internationally recognised PAS 55 Assessment Methodology, published by the Institute of Asset Management.

The results of these responses are scored against the AMMAT scoring standard. An overview of the general criteria the standard requires to be met for each maturity level is shown below.

Figure 2.9.1 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 2.9.2 Orion's maturity level scores



In 2020 Orion again engaged WSP Opus to undertake an independent assessment based on AMMAT and the EEA guidelines. WSP Opus determined that Orion's focus on asset management improvement initiatives, our attention to embedding the right organisational risk management culture, and our focus on continual improvement were reflected in our achievement of an outstanding score of Competent or Excellent in all categories.

The assessment concluded that: "Overall, a very good result for a company with an excellent asset management culture, a strong focus on safety and performance."

For full results see Appendix F, Schedule 13.

2.10 Stakeholder interests

Our key stakeholders and their interests are summarised in Figure 2.10.1.

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 power 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 a company they can trust

Figure 2.10.1 Stakeholders and their interests

Service providers
Having fair access to the business is a core need of the service providers and suppliers. They seek consistent terms with clear specifications, steady workflows, project diversity, information to assist efficient resource planning and support.

Community
Security of supply, safety, reliability, community partnerships, sponsorships, amenity, project impacts, environment, and pricing.

Consumer advocacy groups
Cost and value, tariffs, performance incentives, consumer protections, long term price paths and social investment.

Customers
A reliable electricity supply that is value for money is key to these stakeholders. This means ensuring efficient fault restoration with good communication during events.

Orion team
Employees need a safe and healthy work environment as well as job satisfaction. Clear direction, responsibilities, accountability and productivity play an important part in achieving this. Diversity and inclusion, and opportunities to participate.

Government agencies
Economic efficiency, compliance with regulations, consumer protection cost and value. Environmental performance, low carbon economy, sustainability. Also safety, emergency management and response.

Industry associations
Compliance, reliability, safety, security of supply, customer engagement, market trends, compensation, performance and standards.

Industry groups
Long term planning, security of supply, reliability, partnerships.

Shareholders: Christchurch City Council Holdings Ltd & Selwyn District Council
Shareholders seek a fair return on investment that is commensurate with the risk of that investment. Efficiency, long term value, sustainability, prudent financial management and planning and security of supply.

Media
Outage information, business strategy and planning, environmental protection, cost and prices, issues management and community contribution.

Transpower
Transpower needs to know the load forecasts on Orion's network, any technical connection issues and details of any new investments. They also have a vested interest in security of supply.

Retailers
Reliable service and effective engagement with customers. Cost and value.

Financial institutions
Prudent financial management and planning, and the capacity for debts to be repaid debts as they fall due. They need timely and accurate information and key forecast assumptions, as well as access to senior management.

Lifeline utilities
Preparedness, readiness and response in HILP events.

2.10 Stakeholder interests continued

Figure 2.10.2 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 2.10.2 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

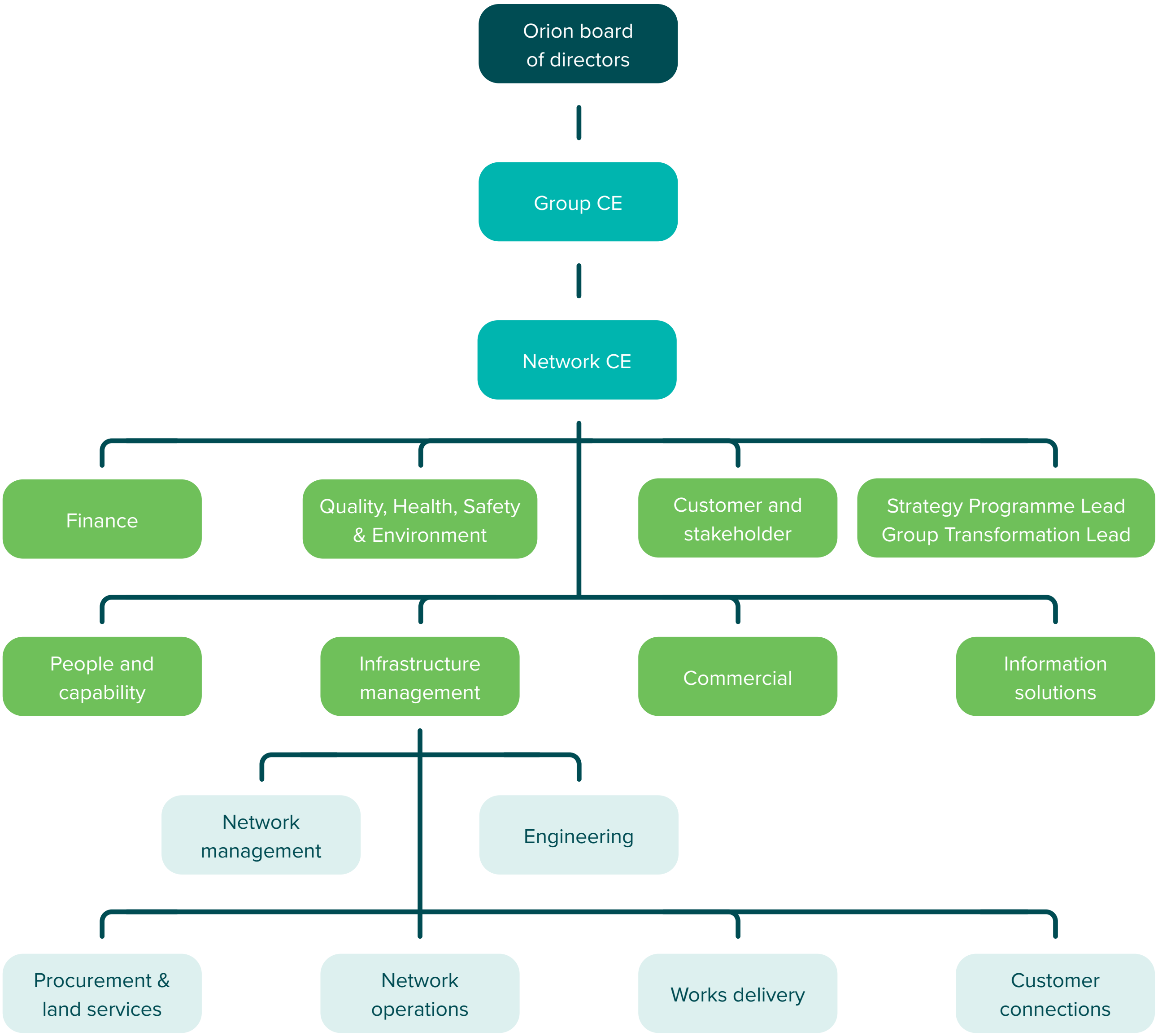
Manage conflicting interest

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."

2.11 Accountabilities and responsibilities

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

Figure 2.11.1 Asset management structure



2.11 Accountabilities and responsibilities continued

Board and executive governance

Our directors are appointed by our shareholders to govern and direct our activities. The board usually meets monthly and receives formal updates from management of progress against objectives, legislative compliance, risk management and performance against targets.

Orion's board of directors is the overall and final body responsible for all decision-making within the company. 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 managers in the Leadership Team is responsible for their budget and operating within their delegated authorities.

Infrastructure responsibilities

The asset management framework is governed by the board, Leadership Team and the Infrastructure Team. Each infrastructure manager is responsible for their part of the network opex and capex. The expenditure for each asset class is also set out in the internal Asset Management Reports (AMRs), which then support this AMP. The AMRs are subjected to an internal approval process, whereby during the year, they go through several checkpoints including infrastructure managers and leadership team review and a selection will be reviewed by the directors.

For detailed responsibilities see Section 8 – Supporting our business.

2.12 Systems, processes and data management

2.12.1 Systems

Our information systems are used to record, develop, maintain and operate our business. The function of the main systems is detailed below:

2.12.1.1 Geographic asset information

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 data 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.

2.12.1.2 Asset database

Our asset database is our central repository for details of the non-spatial network assets. 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 table in Appendix C for more specific detail of information held on each asset group.

2.12.1.3 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

2.12.1.4 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.

2.12.1.5 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 PowerOn 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 overnight to the Electricity Authority’s registry.

2.12.1.6 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.

2.12.1.7 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 3.7.5.

2.12.1.8 Advanced Distribution Management System (ADMS)

We operate an integrated ADMS (PowerOn from GE) 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 big 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 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 automatically 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. Safety documents related to the operating order are also provided directly to the hand-held device. A recent enhancement to this application will also check that an operator has the appropriate certifications for operating the equipment associated with the order before allowing them to proceed.

Distribution Power Flow Analysis (DPF)
DPF is a decision support tool for our Network Controllers. It can perform network power analysis studies that compute electrical network statuses and provide power analysis data to Controllers. DPF studies can run as simulations and include switching schedules and switching work/order and patches.

Service Request Register (SRR)
SRR is a service provider online switching release request system. The online release request system manages requests from multiple service providers who wish to undertake planned work on network equipment. This replaces a largely manual, paper-based system for planned outages.

2.12.1.9 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.

2.12.1.10 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.

2.12.1.11 Data warehouse and BI

A data warehouse that hosts data from financial, asset management and control systems is in place to meet increasing demand for more sophisticated business reporting, analytics and dashboards. Microsoft’s Power BI is deployed throughout the business.

2.12.1.12 Interruption statistics

We automatically post outage information from the PowerOn 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.

2.12.1.13 Demolition tracking

Demolition jobs are dispatched to the field and demolition details returned electronically.

2.12.1.14 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 5.6.2.1.

2.12.1.15 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.

2.12.1.16 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.

2.12.1.17 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.

2.12.1.18 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 PowerOn 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.
- 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

2.12.2 Asset data

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. The data has become more complete and more accurate over time.

Due to improved asset management plans, regulatory compliance and better risk identification and management, 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 the network is accurate. 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

2.12.3 Short term developments

We are engaged in several projects that will deliver improvements in key systems. This includes the increased automation of processes related to procurement and a review of voice communications systems.

Two key projects are:

Customer Relationship Management – we are in the early stage of defining requirements for a CRM system that will be delivered progressively over the next three years.

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.

2.13 Significant business assumptions

2.13.1 Asset management processes

2.13.1.1 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.

2.13.1.2 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 as a result of a major event or equipment failure, we have not included the actual consequences of a forecast/hypothetical major event in our AMP forecasts.

2.13.1.3 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.

2.13.1.4 Network development

Section 6 of this AMP outlines projects that will ensure that our network will continue to meet our customers' expectations of service.

Our network pricing aims to promote active participation from customers, for example, many of our major customers respond to our price signals and reduce their demand when our network is running at peak demand. We maintain a watching brief on Transpower's proposed changes to the Transmission Pricing Methodology, due to take effect in 2023. We envisage that the uptake of new technology such as electric vehicles, batteries and solar panels will accelerate but will have only modest low voltage network impacts in the 5-10 year time frame. We have assumed that industry rules will ensure that generation connections will not be subsidised by other industry participants, including Orion, or customers.

2.13.1.5 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 also our other business drivers and assumptions discussed in this section.

2.13.2 Changes to our business

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

We are currently transitioning to a "Primary Service Delivery Partner" (PSDP) contracting model and moving away from our existing contracting model. It is proposed that Connetics will undertake the role as the PSDP.

This new contracting model is expected to be operational by October 2021 and will help us to more effectively and efficiently meet our objectives by enhancing service providers' capability development, and ensure they have dedicated focus on health, safety, quality and the environment.

2.13.3 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 uncertainties that could impact our assumptions, and considered a range of scenarios. We face these sources of uncertainty confident in our ability to adjust our planning if needed.

Potential uncertainties in our key assumptions include:

- **Regulation –** future changes to regulation are unlikely to reduce our targeted service levels and are likely to continue the pressure for ensuring cost effective delivery of network services. We believe that the structure of our network pricing and our management processes encourage the economic development of the network and the chances of adverse significant changes in the regulatory framework in this regard are low.
- **Government response to the Climate Commission's draft advice –** the Commission's urging of the need for New Zealand to take bold and urgent climate action and any significant changes in Government policy could create transformational change in our industry and service provision.
- **Changing customer demand –** the uptake of new technologies such as electric vehicles, photovoltaic generation and battery storage is forecast to increase. These forecasts are uncertain and we have researched the impact of these technologies for different uptake scenarios to inform our thinking.
- **The regeneration of Christchurch –** the ongoing regeneration of Christchurch's central city and the future of the 'red zone' are influenced by the Crown, Christchurch City Council and Ōtākaro Limited. It's also influenced by private developers.

  There is uncertainty regarding the timing and extent of some key projects as the rebuild continues.
- **High growth scenario –** growth scenarios form a relatively narrow range. Our peak demand forecasts include a range of scenarios to test the impact of new technologies. The high growth scenarios do not cause

a material uplift in network constraints and hence a material uplift in network investment or service provider resource requirements. Large capacity requests from major customers create manageable uncertainty.

- **Resourcing of skilled service providers and employees due to demand –** Powerco successfully applied to the Commerce Commission for a CPP and other EBDs Wellington Electricity and Aurora have followed. This will put further upward pressure on labour rates and availability in the next period.
- **COVID-19** – supply chain issues and uncertainty around the frequency, extent and duration of a resurgence in COVID-19 may impact the plans described in this AMP.

2.13.4 Price inflation

In this AMP our cost forecasts are stated in real dollars in FY21 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.

We base our inflation assumptions on forecast information provided by PwC. PwC uses and extrapolates information provided by NZIER. We generally apply a labour cost index (LCI) to the estimated labour component of capital and opex, and a producer price index (PPI) to the other components of our capital expenditure and operational expenditure.

We adjust the LCI forecast provided by PwC to reflect our local view of wage and salary increases. This affects nominal information contained within the system operations and network support and business support forecasts contained in Appendx F, Schedule 11b.

2.13.5 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 timing of our network projects
- one or more large energy customers/generators may connect to our network requiring specific network development projects
- Government measures to keep New Zealanders safe from any escalation in COVID-19 or other pandemics may impact resource availability and delay our work programme
- 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
- requirements for us to facilitate the rollout of a third party communications network on our overhead network could lead to substantial preparatory work to ensure the network is capable of meeting required regulatory and safety standards. This could lead to resource issues and short-medium term increases in labour costs

Government measures to keep New Zealanders safe from any escalation in COVID-19 or other pandemics may impact resource availability and delay our work programme

3

Managing risk

Photo: Network Operator, Brad Nicholson checking an Orion kiosk in Burnside.

Contents

3.1 Introduction

Prudent risk management strengthens our ability to provide a electricity delivery service that is safe, reliable, resilient and sustainable. Our risk management aims are to:

- support Orion's Purpose and objectives
- support our community's aspirations for a 'liveable' region that has strong connected communities, a healthy environment and a prosperous economy
- identify and manage our significant risks in proportionate, timely and cost-effective ways
- continuously improve

Our approach 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
- good risk management relies on good judgment, supported by good 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 shifts away from fossil fuels. We expect this reliance on our service to continue for the long-term.

Our community will increasingly depend on our electricity delivery 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.

Our lifelines responsibilities are set out in Section 60 of the Civil Defence Emergency Management (CDEM) Act. 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, GNS Science estimates that there is a 30% 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:

- climate change impacts and other environmental issues are increasingly important and urgent for our community and other stakeholders
- our customers will increasingly convert from carbon-based fuels to renewable electricity
- our customers will increasingly inject power back into our electricity distribution network
- global risk sources such as pandemics and cyber-crime 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

Our community will increasingly depend on our electricity delivery service, so it's essential we identify and manage our key risks.

- electricity distribution networks have specific hazards and risk sources by their very nature
- our industry is 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

In summary, our risk context:

- is complex and dynamic
- has significant local, national and global downside risk factors
- also has significant upside opportunities – especially related to long-term customer demand growth for our electricity delivery service, as our community increasingly shifts from carbon fuels to renewable electricity.

3.3 What our community wants from us

In light of our risk context and through our ongoing customer engagement, 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 previous earthquake experience tells us HILP events can cause extensive damage to our assets and prolonged power outages.

Our customers and community may suffer extreme adverse financial and non-financial impacts from prolonged or frequent interruptions to their power supply, especially if they happen in winter – so we aim to continuously:

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

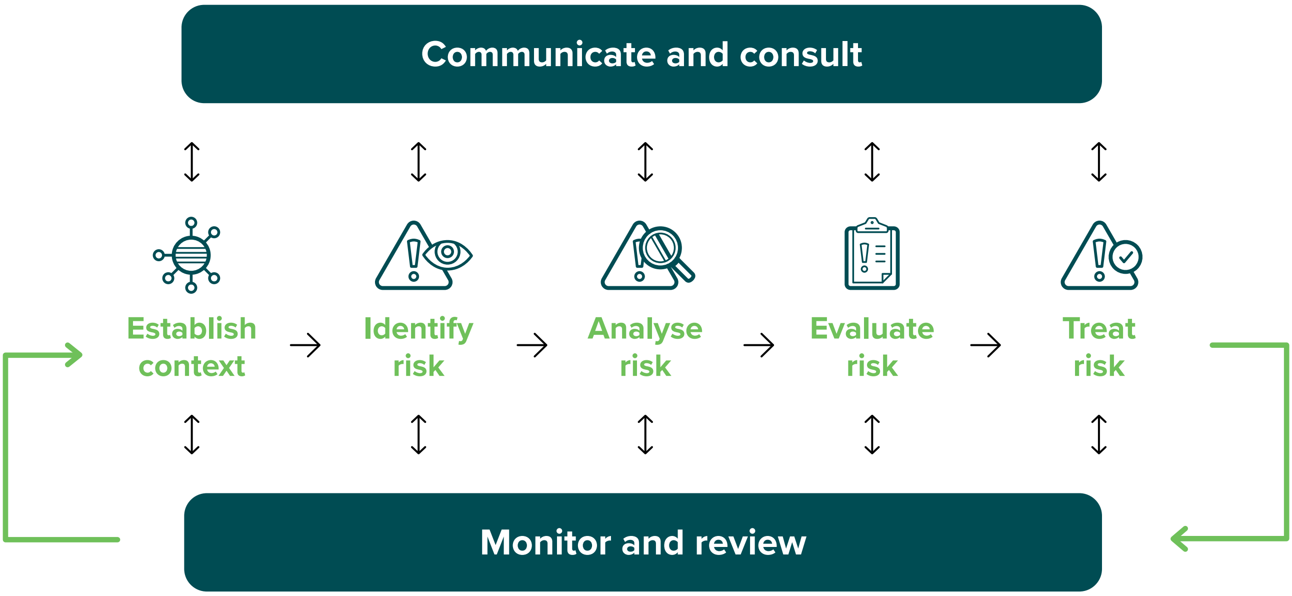
We especially focus on our critical network assets and systems, for example our network control systems and our 33kV and 66kV sub-transmission assets, as these high voltage assets supply the greatest numbers of our customers and they can be the most complex to repair or replace if they are damaged.

3.4 Our approach to risk management

3.4.1 Our risk management process

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

Figure 3.4.1 Our risk management process



3.4 Our approach to risk management continued

In summary:

- we first establish the appropriate context that's relevant to our objectives and our significant risks
- we then identify our significant credible risks – especially those with significant potential consequences
- we then analyse and assess those significant credible risks – the potential credible consequences and their likelihoods, including the effectiveness of our current controls
- we then decide whether/how to treat our risks to eliminate, reduce, transfer or accept them
- we then act to treat our significant risks – in a timely and effective way

We aim to:

- view risk as presenting both threat and opportunity; to look for both aspects in each situation
- consider good evidence, experience and history to inform our judgments
- collaborate internally and externally as appropriate. Collaboration helps to bring different experience, knowledge and perspectives to reduce bias and blind spots
- acknowledge that we can't prescribe set procedures in advance for all risks, in all contexts, at all times
- be proportionate and treat our significant risks as reasonably practicable
- continually review and improve

Consistent with the international risk management standard (ISO 31000:2018), our overall risk management culture is depicted in Figure 3.4.2. In matters of health and safety, our risk management appetite remains low, with zero tolerance. In other areas our risk management appetite is evolving to take a less conservative approach, where we consider the potential upside in a situation, and how we might manage our response to leverage the possibilities it presents.

Figure 3.4.2 Our risk management culture

Our risk management culture is an integral part of our risk management process.

Most of our everyday risk management is undertaken through our line management as part of their everyday duties.

3.4.2 Our network risk management

We aim to be proactive and prudent network managers, and 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, resilience and reliability
- 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

3.4.3 Our people risk management

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

- a healthy and safe workplace
- a collaborative, diverse and inclusive culture
- effective employee recruitment and retention
- effective capability development and training
- effective long-term succession planning for key competencies

We also support wider industry competency initiatives – 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 learning environment support us on this journey.

3.4.4 Our commercial and financial risk management

We aim to have sustainable revenues to support the ongoing investment required to meet the long-term interests of our shareholders, customers and community. We aim to 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
- sound internal controls

3.4.5 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.

3.4.6 Our insurance

Insurance is the transfer of specified financial risks to insurance underwriters. 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 and statutory liability

Our key uninsured risks, that 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
- contract works
- plant and equipment
- motor vehicle third party
- product liability

We aim to have sustainable revenues to support the ongoing investment required to meet the long-term interests of our shareholders, customers and community.

3.5 Our risk management responsibilities

3.5.1 Our everyday risk management

Orion's board of directors oversees the risks that have the greatest potential to adversely affect the achievement of our objectives. Management regularly reports to the board on key issues and risks.

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:

- Strategic programme lead – helps to coordinate our management and governance processes, our risk management framework and our insurance programme

The CDEM Act 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
- Quality, Health, Safety and Environment – six FTEs help our line management to continuously improve our processes in these areas
- Risk steering committee – this was established in 2020 as an ongoing cross-functional and diverse team of managers and employees that aims to provide support, guidance and oversight to the organisation's identification and management of current and emerging risks.

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

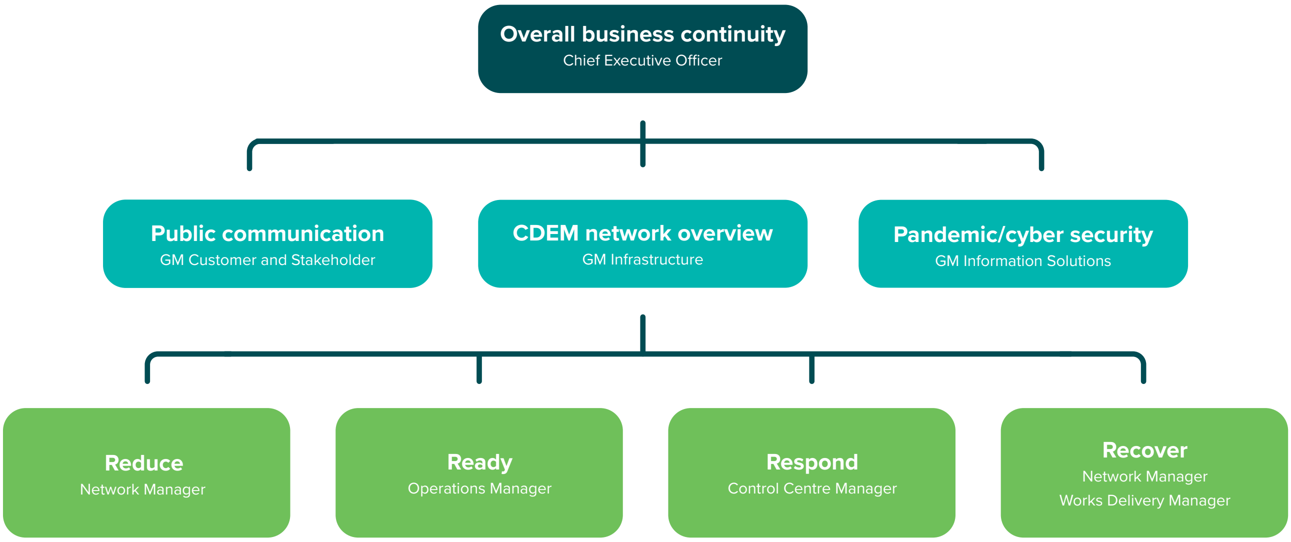
3.5.2 Our HILP/crisis risk management

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 risks that have the greatest potential to adversely 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. A good example of this was that we strengthened our key substations prior to the 2010/11 Canterbury earthquakes and this significantly reduced the impacts on our network, our customers and our community. We have also invested to increase our 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 aim to smooth our planned network opex and capex over time so that our key service providers have planned workflows that can be put on hold when HILP events occur.

  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 and prioritise 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 that following the Canterbury earthquakes, we invested to increase the resilience of our network IT and communications systems, our 66kV underground cables in the east and north of Christchurch, and our base for our key emergency service provider, Connetics.

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

- natural disasters
- 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 aim to assess our risks in a consistent way, so we have high-level guidelines to help our judgments. 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 key risk assessments as a product of consequence and likelihood. This includes a simple risk ranking system 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

Our **consequence rating** guidelines aim to inform our judgments. We recognise that 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 aim to 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 aim to reflect those credible scenarios, including the risk that our current risk treatments are ineffective

Our **likelihood rating** guidelines also aim to inform our judgment. Likelihood is expressed within a time period. When considering likelihood, we aim to 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

> **We aim to assess our risks in a consistent way, so we have high-level guidelines to help our judgments.**

3.6 Our risk assessments and risk evaluations continued

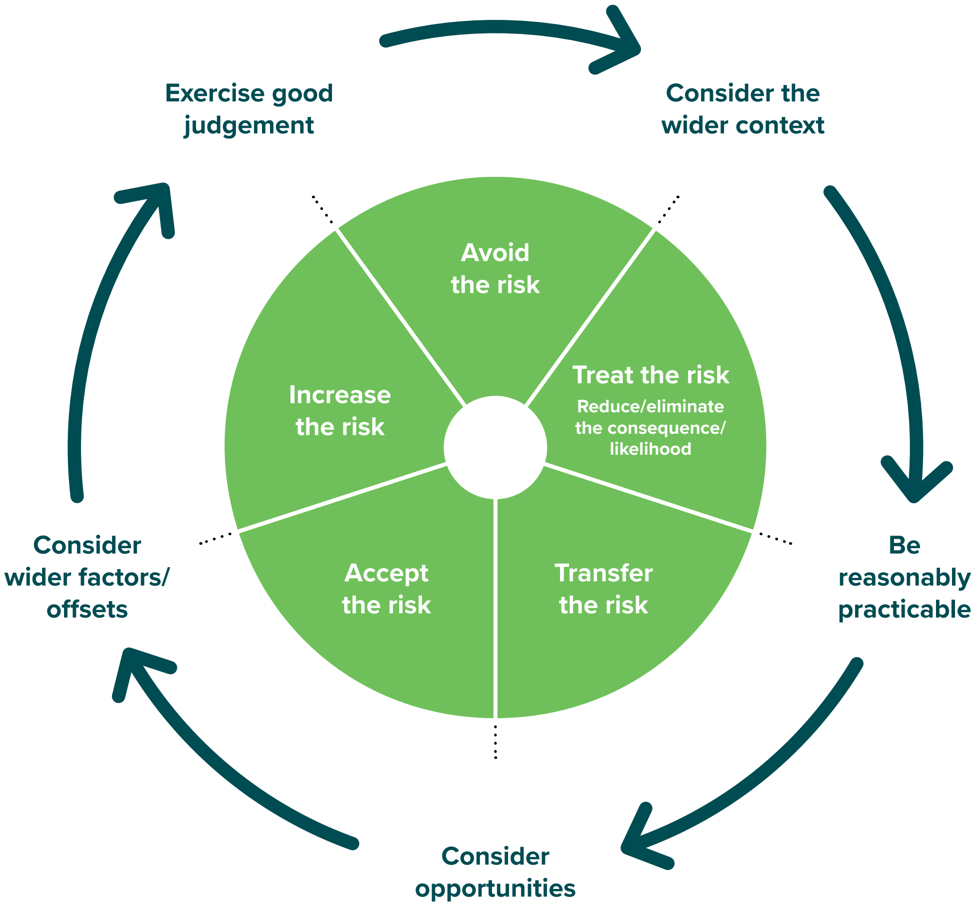
3.6.2 Our risk evaluations

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 judgment. 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	LT/board
Very high	Take timely action to treat risk	Monthly, and as appropriate	LT/board
High	Treat risk if reasonably practicable	Quarterly, and as appropriate	GM/LT
Medium	Consider treating risk if reasonably practicable	Annual, and as appropriate	Line/job manager
Low	Accept risk, manage as per normal procedures	Annual, and as appropriate	Line/job manager

3.7 Our key operational risks

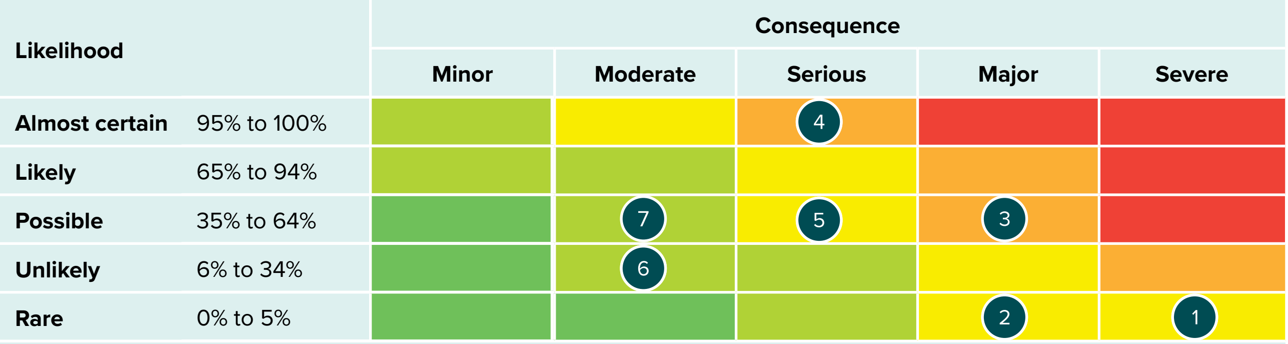
We believe that our key risks are:

Table 3.7.1 Our key risks

Key risks	**Examples**
Natural disaster	HILP events – for example, major earthquake, tsunami triggered by a major earthquake or severe storm
Fatality or serious injury	Fatality or permanent disability to a worker, service provider or other person
Serious cyber security breach	Security breach that especially affects our network control systems
Major network asset failure	Extensive network asset damage and/or extended outages to many customers
Pandemic	Pandemic that causes business continuity issues, including supply chain, people capacity
Weather event	Weather event that results in significant business disruption – becoming more frequent due to climate change

Our overall assessments for these key risk categories (six specific risks, with 1 being the highest risk and 7 the lowest) are shown in Table 3.7.2.

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%					
Possible	35% to 64%		7	5	3	
Unlikely	6% to 34%		6			
Rare	0% to 5%				2	1

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

3.7.1 Health and safety

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

We continue to strengthen our health and safety focus. We're vigilant in identifying risk, and continually improve our health and safety processes and outcomes.

Our management of health and safety is primarily achieved through our operational systems, utilising a 'risk based' approach, where we focus on situations which can result in negative impacts upon people and property – and on those which are more likely to occur.

We aim to actively identify and manage the risks typically associated with operating an electricity distribution network including by way of:

- a collaborative, learnings-based focus into our safety incident investigations
- continuous improvement in our risk management and reporting
- quality assurance oversight to provide a better overview of interrelated factors
- follow-up for all reported incidents and formal investigations as appropriate
- well-developed and documented policies and procedures
- working with our service providers to encourage safer practices when working around Orion infrastructure
- trained and competent field workers who can work in complex and dynamic environments
- remotely operated devices to monitor and operate aspects of our network

We have a dedicated team of people help us maintain a focus on the health, safety and wellbeing of our people, our service providers, and our community. Our Health and Safety Committee has employee representatives from across Orion who meet monthly to review incidents, opportunities for improvement in work practices and the work environment, and to assist in the education of our people.

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 'good practice' management of those risks.

We actively consider potential health and safety risks when we design and construct new network components, through our documented 'safety in design' process. We carefully document and regularly review our work policies and procedures to ensure they provide accurate guidance for those working on our infrastructure.

When considering our people, we recruit, train and equip our team members appropriately for their roles. Our team members are faced with challenging decisions each day, and 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.

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

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 distributors, the Electricity (Safety) Regulations require us to have an audited public safety management system, with the aim to prevent harm to the public or damage to third party property. To demonstrate our compliance 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 compliant.

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 aim to:

- prevent access to restricted areas by the public and unauthorised personnel
- prevent inadvertent access to extremely hazardous areas by authorised personnel
- prevent entry by opportunist intruders without specialised tools
- slow or impede determined intruders

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 health and safety performance and eternal vigilance by every team member.

3.7.2 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.

GNS Science estimates that there is a 30% chance of a major Alpine Fault earthquake in the next 50 years and the risk of other local faults only increases that 30% chance for our region. It is important to note that none of the earthquakes since 2010 were caused by a major rupture of the Alpine Fault.

An Alpine Fault earthquake would be centered 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. A major Alpine Fault earthquake may result in a major outage of up to seven days 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 next major planned resilience initiative is to replace the remaining 40km of oil-filled 66kV cables over ten years or so – starting in FY24. These cables represent old technology and the skills to maintain and replace 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 the west.

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 employees to work remotely for extended periods of time
- a policy and practice to plan-to-plan and adapt following a major event as necessary

In summary, we have implemented and continue to implement practical steps to address our earthquake risk exposures. Our most significant planned resilience project in this AMP is our replacement of the remaining 40km of oil-filled 66kV cables over the next 10 to 15 years.

3.7.2.1 Tsunami

Another major natural disaster risk is tsunami, most likely from a major earthquake off the coast of South America. This could result in an outage of up to three days 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.

> **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.**

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 learnings from a major wind storm in 1975, snow storm in 1992 and wind storm in 2013 – particularly for rural areas in our 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.

Our urban network is largely underground – and 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. In the most severe storms, most of the trees and branches concerned are well outside regulatory cut zones. There is currently no scope for us to require private tree owners to remove such 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 believe that flooding is a medium to low risk for 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 head office, including our control room, is not at significant risk from flood.

> **In 2020, we published our first annual report in accordance with the guidelines published by the Task Force for Climate-related Disclosures (TFCD). Our *Climate Change Opportunities and Risks for Orion* report is available on our website.**

3.7.3.1 Climate change

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

- **upside growth opportunities** – demand for our electricity delivery service will continue to grow as our community continues to shift from burning fossil fuels to renewable electricity
- **physical risks** – these can be event-driven, such as more frequent and severe storms, or longer-term shifts such as gradual rising temperatures and sea levels
- **transition risks** – these can be wider changes – such as to the economy, regulation, technology, insurance markets or community preferences and behaviours

Overall, we assess that our upside growth opportunities from climate change will outweigh our physical and transition risks over the next ten years. In fact, we believe that we have 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, resilient, reliable and sustainable electricity distribution network.

Our largest potential impacts relate to vegetation and more frequent and severe storms that will affect our largely-overhead rural network.

We already engineer and lifecycle-manage our network to be resilient to storms and have active vegetation management programmes in place. Our team will continue to improve our understanding of climate effects on our network, in order to adapt and mitigate risks where appropriate, or reasonably practicable.

We assess our transition risks as low to moderate over the next ten years, with the largest potential impacts relating to the pace of introduction of new technology. Because of the unknown nature of these changes and the technology that accompanies them, we prefer to view this risk as an opportunity. We believe our best management lies in promotion of an adaptable and agile business that can quickly adopt or accommodate new innovations. Adverse regulation could also potentially impact the level or structure of our delivery pricing, or could relate to operational aspects of our business.

In 2020, we published our first annual report in accordance with the guidelines published by the Task Force for Climate-related Disclosures (TFCD). Our *Climate Change Opportunities and Risks for Orion* report is available on our website.

3.7.4 Pandemic

COVID-19 brought the risk of a pandemic into sharp focus. As an essential service provider Orion has been acutely conscious of our responsibility to maintain vital power services to our community throughout this pandemic. 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 was a risk of our people contracting COVID-19 and the need to limit any spread throughout our workforce. We took significant steps to ensure the safety and wellbeing of our staff, and especially those who worked in critical control centre and customer support roles, as well as our operators in the field.

We implemented processes to ensure our critical service providers were equally vigilant with their teams' health and safety practices.

Orion's focus during Alert Level 4 was on undertaking essential work and our crews and service providers remained on the road to ensure services were maintained. This minimised power outages for people at home and in workplaces that were an essential service and were still operating. It meant our annual work programme got off to a slow start in 2020, and placed pressure on us to catch up on planned work later in the year.

Supply chain issues are beginning to impact on delivery of components from overseas manufacturers for network maintenance and development projects, however increasing our advance purchase volumes for critical components has allowed us to minimise the impact of this situation. This risk may increase in future.

Many businesses felt the impacts of COVID-19 on their ability to operate. To date, we have not seen significant bad debt issues for Orion or retailers and have experienced less than forecast reduction in revenues. However, rising bad debts and reduced revenues remain risks to the sustainability of our business.

Throughout the COVID-19 pandemic Orion swiftly implemented a broad range of protocols that enabled us to keep our people safe while continuing to maintain essential power services to our community. We activated our Pandemic Response Plan which sets out how we undertake core business functions and provide a continuous supply of electricity to the community during a widespread health emergency. Risk management measures implemented included:

- isolating each member of our essential Control Room and Customer Support team - reducing unnecessary interaction with the people who run our essential services
- ensuring as many of our people as possible worked at home - this supported minimising movements in our community and reduced the number of people working in Orion's building at any one time so that those who must be there were safe
- splitting the Orion team into two teams - and ensuring members of one team did not have physical interaction with members of the other
- no longer allowing visitors to our operational headquarters
- cancelling non-essential face to face meetings and non-essential travel
- encouraging our people to practice physical distancing – or consider other options to face to face meetings e.g. Microsoft Teams meetings, phone conferences or email
- taking extra steps to ensure our workplaces were clean, hygienic environments - and distributed more hand sanitising products throughout our headquarters and operators' vehicles
- asking our people to stay at home if they felt unwell
- supporting our people to self-isolate if required
- activating our alternative Control Centre and Customer Support Centre

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. While the future remains uncertain, we continue to monitor the situation closely and use what we have learned to prepare for other pandemics which global health experts predict are likely.

3.7.5 Cyber security breach

All businesses are now potentially susceptible to cyber-attacks from any part of the globe. We implement measures with the aim to prevent such attacks. Our information systems are vital to our ability to deliver a resilient, reliable, safe 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

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.

3.7 Our key operational risks continued

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. Our customers benefit from the services we can safely provide online, our 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. 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 staff 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.

3.7.6 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 recently 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 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 7.19.

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.

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**

3.7.6.2 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.

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.

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 54 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 key sites
- simple and low-cost hold-down ties for transformers
- 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 overhead lines in rural areas are exposed to extreme weather events. Subject to the ability of our repair teams being able to access the affected areas, they are relatively easy and quick to repair, but there may be outages of up to three days in some remote areas of our network. 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.

We have rigorous engineering standards and systematic inspection processes in place for our overhead lines and towers.

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 of up to seven days or more.

We rate this event as a medium to high risk over the next 50 years. We plan to replace these cables with modern and resilient XLPE cable over the next 10 to 15 years.

For management of asset related risk, see Section 5.6.2.

3.7.7 Other risks

In Section 6 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.

3.7.7.1 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 aim to reduce electrical losses on our network. We do this via our efficient network delivery pricing that signals system winter peaks – high loadings increase electrical losses – and via our network load management systems, especially our hot water cylinder control systems. It makes good environmental sense to reduce winter system peaks – in order to reduce electrical losses and to reduce the amount of network necessary to deliver electricity.

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. In our memorandum of understanding with the Ministry for the Environment, we commit to keeping annual SF_6 gas losses below 1% of the total contained in our circuit breakers. Our environmental management procedure for SF_6 gas aims to ensure we achieve that target.

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

3.7.7.2 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

We take practical steps to prevent undue harm to the environment.

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.

Our risk management approach is to:

- keep up do 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.

3.8 Our resilience

3.8.1 Introduction

Clause 14 of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 (IDD) asks us to disclose:

- areas of our network that are vulnerable to HILP events
- our strategies and processes to identify and address those vulnerabilities
- our emergency and response plans
- our overall resilience

We define resilience as our ability to withstand, respond to and recover from significant, especially HILP, events.

As a lifelines utility, resilience is fundamental to our ability to provide a sustainable and fit-for-purpose service for the long- term benefit of our customers and our community.

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

3.8.2 Our key network vulnerabilities

The lifelines section (Section 3.7.6) describes the HILP vulnerabilities for our 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 to fifteen years.

3.8.3 Our conclusions on our 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
- be ready to respond and recover – for example, we have prudent service provider practices, 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 community. However, we can always improve and this AMP describes many of our initiatives that aim to do just that.

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 community.

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..
Security of supply standard	This standard, see Section 6.4.1 of this AMP, 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 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 participant telling us how she thinks Orion should approach encouraging people to trim their trees away from power lines.

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 strategic themes and foundation of our Group Strategy.

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 contains specific service level targets for reliability and other aspects of our business, some of which are outside the scope of this AMP.

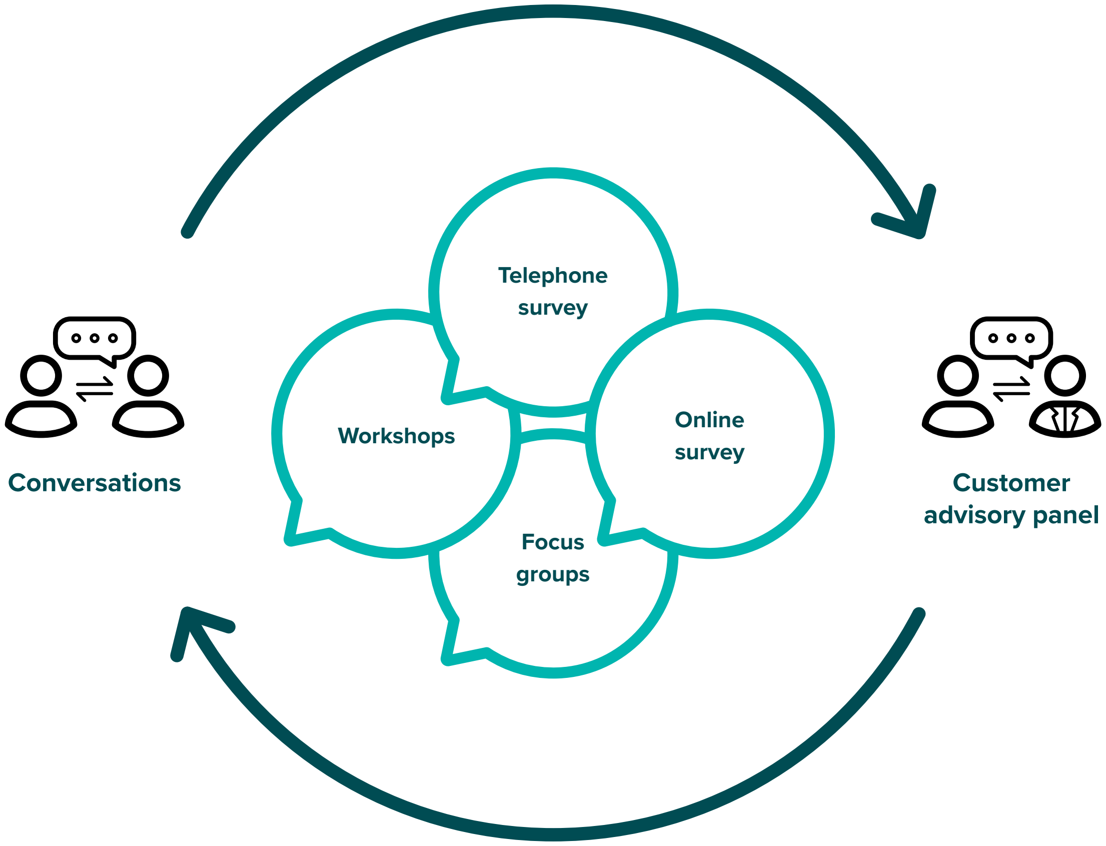
> **Orion works hard to better understand the needs of our customers, and give them a voice in our decision making.**

4.2 Customer engagement

As well as physically maintaining our infrastructure, keeping our network operating sustainably is also about knowing our customers, what their needs and aspirations are, and ensuring we remain relevant 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 new technology and shifting customer expectations.

Our customers want more control over where their energy comes from, and how they consume it. Customers are looking for flexibility and more choice.

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, views on network reliability, level of trust in Orion, and the effectiveness of our communications.

Last year we extended this telephone survey of 800 urban and rural residential customers to include canvassing the views of 200 small to medium businesses in our region.

Because we survey a robust 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, our communications or Orion's approach to community sponsorships.

In November 2019 we also commissioned 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 "Powerful Conversations" workshops

Our latest series of "Powerful Conversations" workshops with groups of around 20 customers, explored their views on what represented good value for money in Orion's expenditure budgets; who should be responsible for trimming trees away from powerlines; what people thought Orion's priorities should be to contribute effectively to our region's sustainability and their preferences for the duration of planned power outages.

4.2.4 "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 around 2,500 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.

4.2.5 Major customer engagement

All of our major customers are 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 machines.

4.2.6 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.

In late 2019, we commissioned independent researchers to interview a range of our service providers to find out how we could further develop our relationship with people critical to the delivery of Orion's service.

4.2.7 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 texts. We also provide presentations to local Community Boards, run local advertising and provide information via community social media channels.

4.2.8 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
- Twitter updates
- sponsorships and partnerships that enable us to engage with our community on important power matters, such as encouraging businesses to consider adding electric vehicles to their fleets through our "EV Experience" partnership with the Canterbury Employers' Chamber of Commerce
- Displays at trade shows for the farming and general community

4.2.9 Advertising

In the spirit of continuous improvement, In the past year we have overhauled our community advertising campaigns to improve their effectiveness and utilise increasingly popular online channels. Through online, newspaper, magazine and radio channels our new 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 2020 COVID-19 lockdown periods.

4.2.10 Website

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

We recently 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 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 What our customers have told us continued

4.3.1 Customer satisfaction research results

We gather a wealth of information on what our customers think of our service. In our annual customer surveys, they rate us highly on key service metrics including our Net Promoter Score, and our Customer Support team's handling of their calls. As a reflection of our customer service and network performance, there is a high level of community trust in Orion.

Figure 4.3.1 shows the key results from our latest customer research surveys.

Figure 4.3.1 Key results from our Annual Residential Customer Satisfaction survey, 2020; and Customer Calls research, 2020

Orion's overall performance

NPS +60

Orion's Net Promoter Score

8.8 AVG.

0—10 scale

41%

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

Key perceptions of Orion

87%

agree **Orion is capable and effective**

84%

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

87%

agree **Orion maintains the electricity network well**

82%

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

66%

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

45%

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

51%

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

41%

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

Awareness and perceptions of Orion

46%

Awareness of Orion

96%

Satisfied with reliability of power supply

91%

Level of trust in Orion

40%

Aware of the Orion website

36%

Aware of the Orion Customer Support service

95%

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 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, and they make greater use of Orion's Customer Support team, and website.

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 can be safely accessed 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 2020 annual survey of residential customers found 96% were satisfied with Orion's service reliability. 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.

  On perceptions of our network resilience, while 82% of residential customers tells us they think we get on to fixing the network quickly when the power goes out, a significantly lower number, 51%, agree that we are well prepared for future natural disaster situations. We will be providing customers with increased reassurance around this point.

4.3.4 Health & 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. And in the most important measure of the effectiveness of our public safety campaigning, there were no incidents of electrical harm in our region in FY20.

4.3.5 Sustainability

As we move forward on our sustainability journey, we are looking at how we are aligned to the United Nations Sustainable Development Goals. In our "Powerful Conversations" workshops and interviews with other key stakeholders, we talked with people about what sustainability means for Orion and where they think we should focus our efforts. The goals we found resonated most strongly for our customers and stakeholders are:

- working towards more sustainable communities and cities
- acting on climate change
- fostering good health and wellbeing in our community
- being responsible in the consumption and production of our business

These goals have been embraced in our Group Strategy, see Section 2.4.

4.3.6 Capability

As our industry goes through an era of unprecedented change, so too must our capability adapt to meet changing needs.

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, 87% agree that Orion is capable and effective in the management of our network, and 84% say we carry out our duties very well.

What surveyed customers are less sure of is whether we are prepared for the future. Customers tell us we need to be ahead of developments in the industry and ready to help customers and our service providers adapt to new ways of managing the community's power needs. They encourage us to ensure we are developing the capability that will be needed.

4.3.7 Future networks

At both our "Powerful Conversations" workshops and 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 take advantage of new technologies.

In our annual customer survey, we found customers are less confident in our preparedness for the future – only 41% 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. We acknowledge we must do more to be ready for a changing future and accept the need to improve this perception.

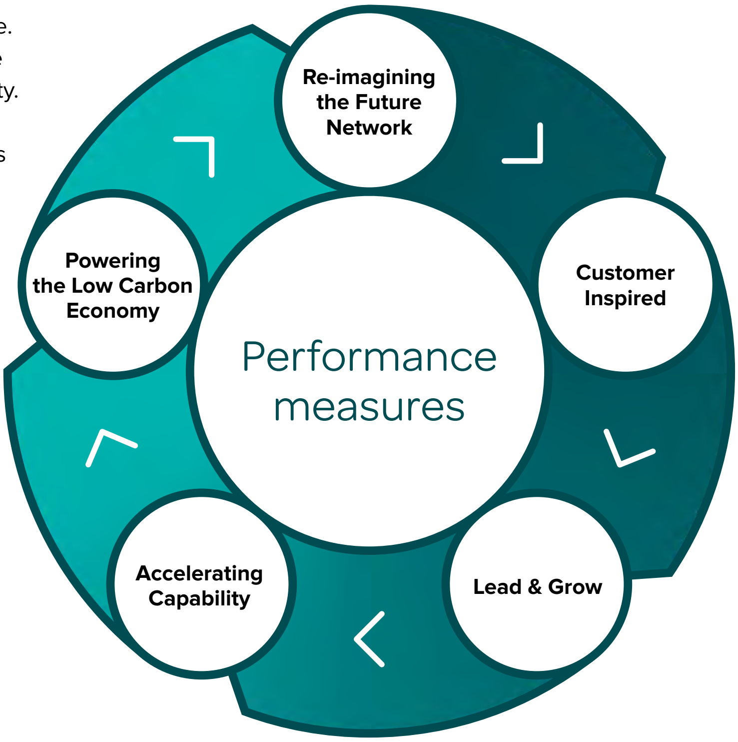
4.4 Turning listening into action

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 inspired • Give us more information when the power goes out	• Added functionality to our website to give regular updates on restoration progress for outages • We now communicate directly with customers for significant planned outages • Offer text alerts to customers for planned outages
Safe, reliable, resilient system • Improve our reliability in Banks Peninsula • Are you prepared for future natural disasters?	• Installed capacity to hook-up generators to maintain Akaroa power service in emergencies, and when undertaking maintenance and upgrade work • Increasing communications about our network resilience projects • Replacing oil filled cables
Health & safety • Keep us safe, but not at any cost	• Revamped our public safety education campaigns for stronger messaging and use more effective, new channels • Collaboration with EBD colleagues on ENA's national tree trimming advertising campaign
Sustainability • Be prepared for climate change	• Published our first TCFD report: *Climate Change Opportunities and Risks for Orion* • Orion has committed to achieving carbon neutrality for corporate emissions by June 2022
Capability • Be prepared for the future	• Orion, and its subsidiary, Connetics, are collaborating with others across the industry through a new initiative called the Energy Academy to transform industry capability and development in New Zealand
Future network • Reassure us you're ready to support our future needs • Be ready for change	• In 2020 we adopted a new Group Strategy which has five strategic themes, one of which is: Re-imagining the Future Network • Began our Low Voltage network monitoring programme

4.5 Performance measures

This section sets out how we measure our performance. Throughout our engagement with customers they have told us that a reliable supply of electricity is a top priority. This is a key service measure. We also monitor our performance against a range of other service measures including customer service, power quality, safety and environmental impact. Table 4.5.1 shows how our measures align with the Orion Group Strategic Themes outlined in Section 2.4. Our Group Strategy is an evolving process, and further measures to reflect our commitment to our future focus are under development. Our current targets and our performance against those targets are set out in this section.



4.5.1 Performance against targets

Table 4.5.1 shows a summary of FY20 performance against target as well as our current targets for the future. We expect the forecast expenditure for our maintenance and replacement strategies, set out in Section 7, will maintain our overall performance at a steady level in line with our customers' expectations.

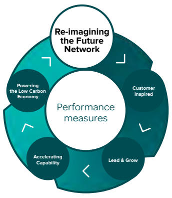
Table 4.5.1 Summary of performance against targets

Orion Group Strategic Theme	Service class	Measure	FY20 targets	FY20 performance	Achieved?	FY21-FY25 targets
Re-imagining the Future Network	Future network	Under development				
Customer Inspired	Customer service	Time for a connection to be available: • Residential greenfield • Residential brownfield • Commercial	Not set	n/a	n/a	75% in < 5 working days* 60% in < 20 working days* 50% in < 20 working days*
		Customer Support caller satisfaction	Not set	95%	n/a	> 85%
		Net Promoter Score	Not set	60	n/a	> 50
Lead & Grow	Network reliability	SAIDI	< 73.4	67.3	✓	Planned < 39.7 Unplanned < 84.7
		SAIFI	< 0.87	0.66	✓	Planned < 0.15 Unplanned < 1.03
	Network restoration	Unplanned interruptions restored within 3 hours	> 60%	69%	✓	> 60%
	Resiliency	Under development				
	Power quality	Steady state level of voltage	< 80	19	✓	< 80
		Level of harmonics or distortion	< 4	3	✓	< 4
	Safety	Safety of Orion Group employees	0 serious events	0 serious events	✓	≤ 4
		Safety of service providers	0 serious events	3 serious events	✗	≤ 4
		Safety of the public	0 serious events	1 serious event	✗	0
Accelerating Capability	Economic efficiency	We discuss capital expenditure and operation expenditure per MWh, as well as operational expenditure per ICP in this section but we do not have a specific target				
Powering the Low Carbon Economy	Environment	SF_6 gas lost	< 0.8% loss	0.86% loss	✗	< 0.8% loss
		Oil spilt	0	1	✗	0

* These targets are being reviewed to align with customer expectations.

4.5 Performance measures continued

4.5.2 Re-imagining the Future Network



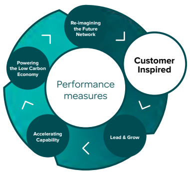
Our Low Voltage (LV) network will increasingly need to support new and more complex two-way power flows as customers progressively adopt new technologies. For this reason, we began our LV feeder monitoring project in FY20. The aim is to develop our ability to monitor and centrally operate our LV network in real time. We are currently working on understanding the type of data we need to collect and why and how the data can be used. See Section 6.2 for more information.

Performance against targets

Targets are under development.

Our Low Voltage (LV) network will increasingly need to support new and more complex two-way power flows as customers progressively adopt new technologies.

4.5.3 Customer Inspired



For the first time, we developed measures and targets for our performance in customer service, commencing FY21. They measure and set ambitious targets for our performance in three key areas:

- **The length of time is takes us to connect a customer to our network** – following their request, and the provision of all necessary information. Customers have been expecting increasingly shorter timeframes for connections, and expressing their frustration at the current average turnaround time. We have provisionally set our new targets to challenge our current performance, and we seek to reduce our connection times. We are reviewing these targets to ensure they meet our customers' expectations.
- **Customer satisfaction with their calls to our Customer Support team** – around 2,500 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 international average NPS of technology companies at +40, our target reflects our goal to have loyal customers who rate Orion in the "GREAT" NPS range.

4.5.4 Lead & Grow

4.5.4.1 Network reliability

Network reliability is measured by the frequency and duration of interruptions to the supply of electricity to our customers. Our goal is to ensure that our reliability performance meets our regulatory requirements and our customers' expectations, established through the various means of consultation discussed in the previous section.

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

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

Performance against target

As shown in Figure 4.3.1, in our 2020 annual survey of residential customers, 96% were satisfied with our service reliability. Our customers also do not want us to continually improve network reliability if it is reflected in increased prices. There comes a point where the added costs outweigh the added benefits, particularly in a predominately overhead rural network. For example, a major improvement in rural reliability would require a large capital investment and a correspondingly large increase in line charges.

Our network reliability performance for FY20 is shown against our targets in Table 4.5.2. The annual network reliability limits were set by the Commerce Commission under CPP regime determined for Orion after the Christchurch earthquakes of 2010-2011. These limits have run from FY15 through to FY19 and our FY20 limits were the same as FY19.

Our new targets for SAIDI and SAIFI for FY21-FY25 are also shown in Table 4.5.2. There are now separate targets for planned and unplanned events, and a new extreme event measure that relates to identification and reporting of rare events. See Section 7 for more information on faults per 100km. Our historical performance and future targets are shown in Figures 4.5.1 and 4.5.2.

4.5 Performance measures continued

Table 4.5.2 Network reliability performance against target

Category	FY20 target	FY20 performance*	FY16-FY20 average	FY21-FY25 targets	
				Planned	Unplanned
SAIDI	< 73.4	67.3	78.1	<39.7	<84.7
SAIFI	< 0.87	0.66	0.88	<0.15	<1.03
Subtransmission lines faults per 100km#	3.7	1.7	2.0	3.7	
Subtransmission cables faults per 100km#	0.8	0	1.0	0.8	
Distribution lines faults per 100km#	18.0	19.8	19.6	18.0	
Distribution cables faults per 100km#	2.8	1.9	2.4	2.8	

* Major event daily limits applied in accordance with CPP

\# As per Commerce Commission disclosure schedule 10(v)

Figure 4.5.1 SAIDI 10 year history and 10 year target, including SAIDI forecast

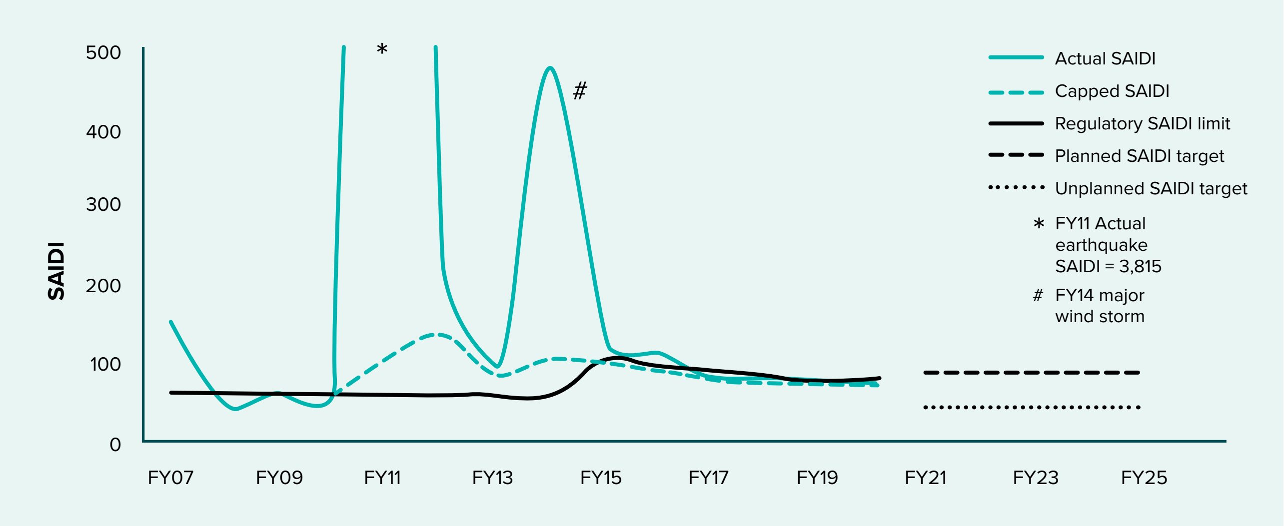
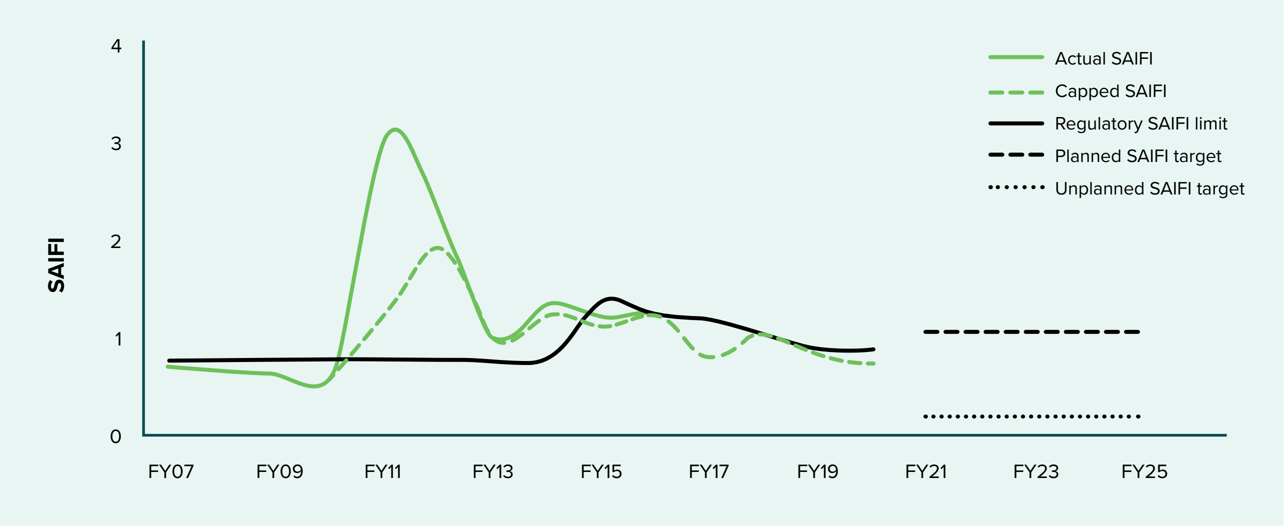


Figure 4.5.2 SAIFI 10 year history and 10 year target, including SAIFI forecast



Comparison by cause and asset class

Figure 4.5.3 shows a further breakdown of SAIDI and SAIFI by asset class and a five-year average comparison graph is shown in Figure 4.5.4. Our 11kV overhead network has always had the highest impact on reliability. The performance of secondary assets, such as communication and control systems, isn't specified as this is inherently captured in the service levels of the primary asset classes. These secondary assets have a latent impact on performance that is only observable through the flow on effects upon the performance of our primary assets. FY20 data of interest includes:

- There were no capped days for SAIDI or SAIFI
- Protection faults were down from 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
- The weather was particularly benign, causing only few issues

See Section 7 for the maintenance and refurbishment strategies needed to maintain performance.

Figure 4.5.3 FY20 SAIDI and SAIFI by asset class and by cause

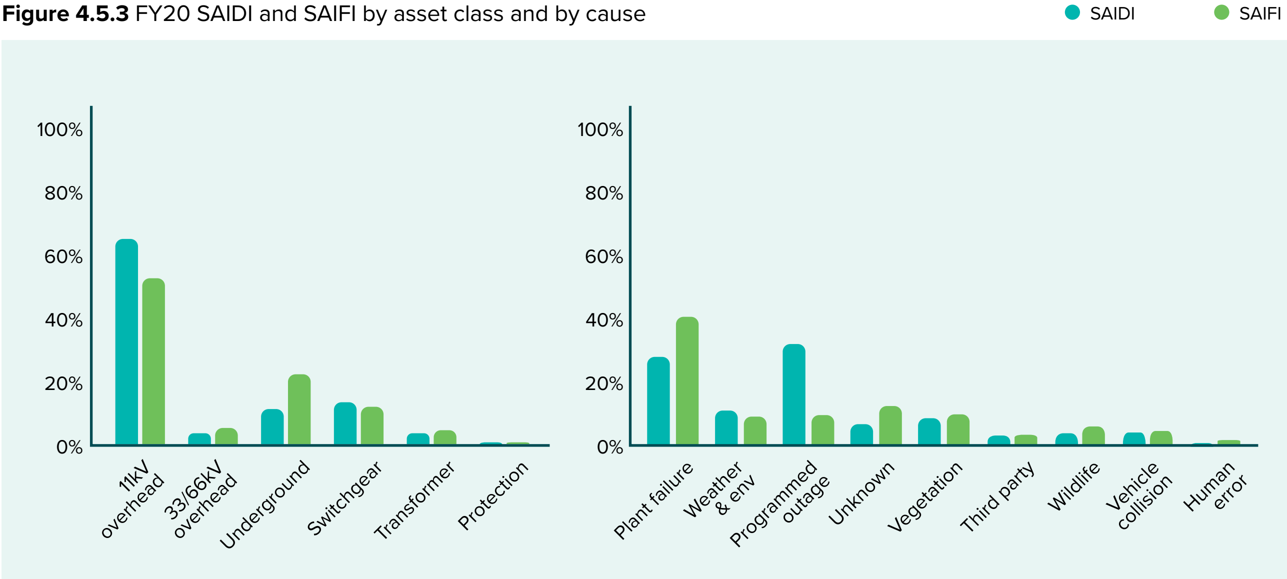
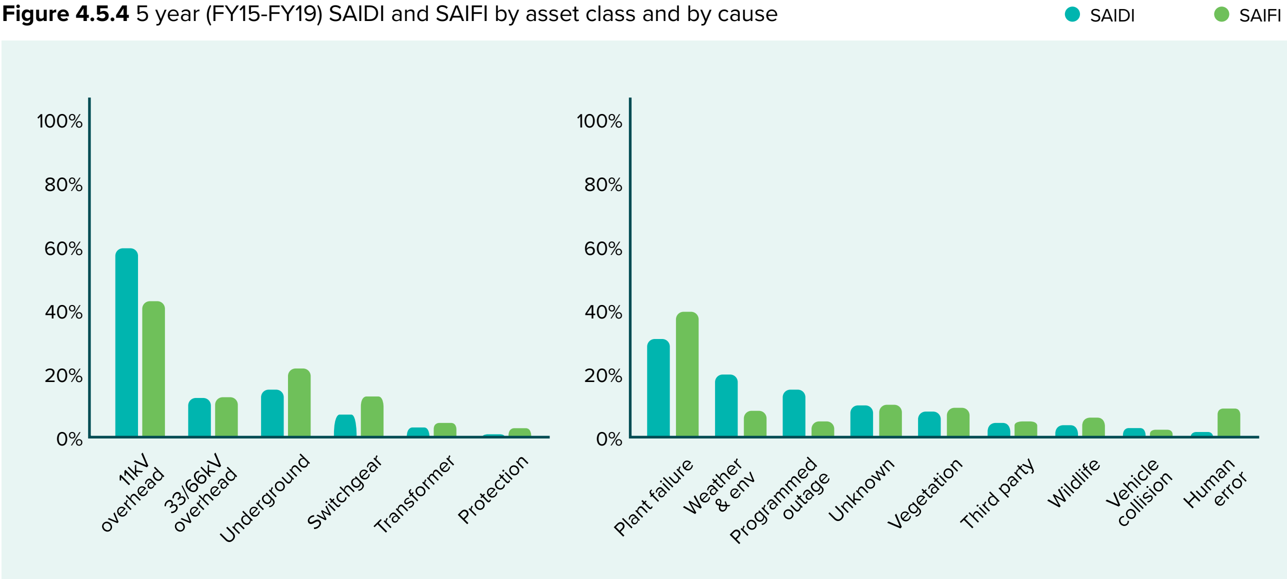


Figure 4.5.4 5 year (FY15-FY19) SAIDI and SAIFI by asset class and by cause



4.5.4.2 Network restoration

Our percentage of unplanned interruptions restored within three hours is based on providing a reasonable level of service at a reasonable cost. 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 it can be seen in Figure 4.5.5, 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 are able to more quickly locate faults and restore supply. Our FY20 target and performance are shown in Table 4.5.3 and future targets are to have more than 60% of unplanned interruptions restored within 3 hours. We have met our target for FY20.

Figure 4.5.5 Unplanned interruptions - % restored in under three hours

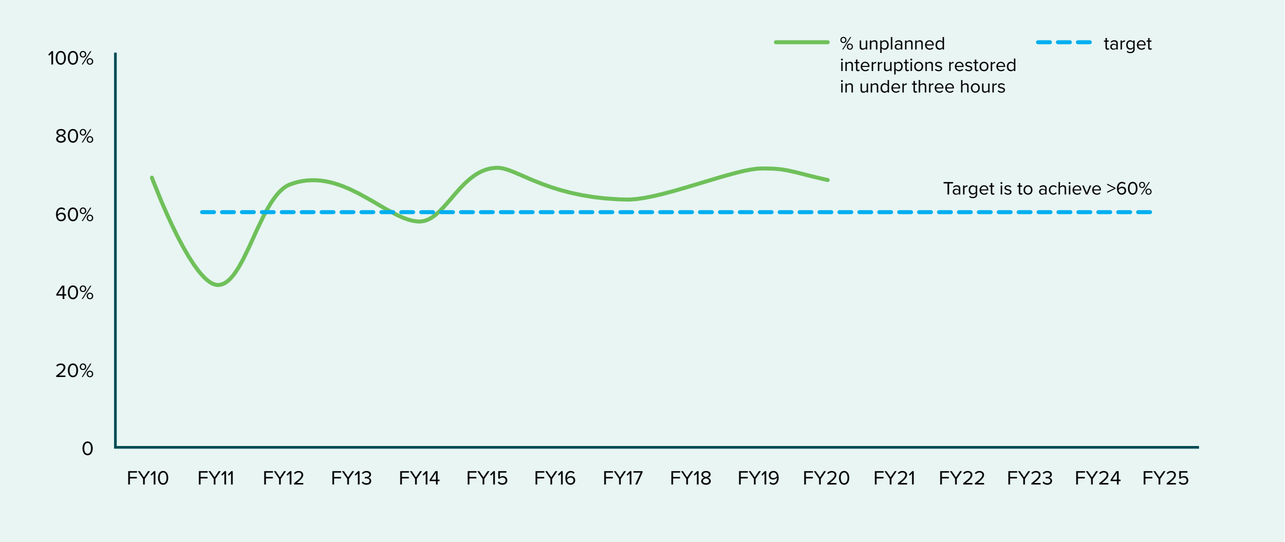


Table 4.5.3 Network restoration performance against target

Measure	FY20 Target	FY20 Performance	FY21-FY25 target
Network restoration	> 60%	69%	60%

4.5.4.3 Resiliency

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. Reliability is a measure of our day to day performance and is measured by the number and duration of power outages to customers. 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. We will look to benchmark ourselves with the work EEA has conducted on RAMMAT.

4.5.4.4 Power quality

Power quality is measured by a range of performance attributes. The two most common and important power quality attributes Orion is able to influence are:

- **the steady state level of voltage supplied to customers** – the range of steady state voltage supplied to customers is mandated by regulation at 230 volts ± 6%. We design and operate our network to meet this requirement. However, despite our efforts unanticipated changes in customer loads or unforeseen events result in some customers experiencing voltages outside these limits for short periods of time. This could affect customer's sensitive electronic equipment. We investigate any customer concerns about voltage fluctuations and if we find Orion is responsible, we will modify or upgrade our network to rectify the problem
- **the level of harmonics or distortion of voltage of the power supply** – the allowable level of harmonics or distortion of the power supply provided to customers is also covered by regulation. 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 strength of the power supply at their premises

An important aspect of maintaining quality of supply is to monitor power quality indices, and this is achieved by 33 permanently connected Dranetz power quality analysers. Our analysers monitor network voltages at 230V end of feeder, 400V start of feeder, 11kV and 66kV. A mix of parameters are measured which define the quality of voltage and current for regulatory levels.

Due to the wide range and type of power issues and the often limited customer understanding of complex technical information, communicating about power quality issues can be complicated. Our approach is to work with the customer's technical representative to gain a mutual understanding of the issues and discuss options for solutions. This results in a common understanding and transparent outcomes. In most cases customers don't require complex information, and simply need a resolution that balances benefits and cost.

Performance against target

Our main objective in relation to power quality is to identify and resolve customer quality of supply enquiries. To achieve this, we fit test instruments close to the point where ownership changes between Orion's network and the customer's electrical installation. Data gathered from the test instruments is analysed against the current New Zealand Electricity Regulations. By applying key regulations in relation to voltage, frequency, quality of supply and harmonics we are able to determine which quality problems have originated within our network. Our network performs well in terms of voltage and quality. We receive a number of voltage complaints every year but only around 20% of complaints are due to a problem in our network, predominantly about power outages. In Table 4.5.4, 'proven' means that the non-complying voltage or harmonic originated in our network. We met our targets for FY20.

Table 4.5.4 Network power quality performance against target

Measure	FY20 Target	FY20 Performance	FY21-FY25 target
Voltage complaints (proven)	< 80	19	< 80
Harmonics (wave form) complaints (proven)	< 4	3	< 4

4.5.4.5 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. Our target of no serious safety events or accidents is the only prudent target we could have to measure safety.

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 staff and service providers with indicators of potential harm when working on and/or near our assets.

Performance against target

We had a total of four safety events in FY20 and therefore did not achieve our target of zero events. WorkSafe was notified of these events, which were:

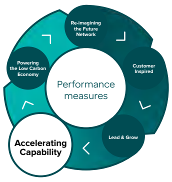
- a service provider received an electric shock while testing a circuit breaker
- a service provider caused a gas leak while working on cable joint
- a service provider tripped on scaffolding while working at a substation
- a member of the public experienced a minor electric shock in their home which traced back to a network fault in an Orion distribution box

We have modified our future health and safety targets to four or less safety events per year and we believe this is a more reasonable and realistic target based on the type of activity we carry out. 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.

Table 4.5.5 Safety performance against target

Measure	FY20 Target	FY20 Performance	FY21-FY25 target
Safety of Orion Group employees	0	0	≤ 4
Safety of our service providers	0	3	≤ 4
Safety of public	0	1	0

4.5.5 Accelerating Capability



Capability underpins operational performance, sustainability and economic efficiency.

Economic efficiency reflects the level of asset investment required to provide network services to customers, and the operational costs associated with operating, maintaining and managing the assets. Our customers are very price conscious. They expect us to operate efficiently and keenly balance the cost impacts of maintaining and developing our network against the benefits to them as consumers. We have adopted the following measures of economic efficiency:

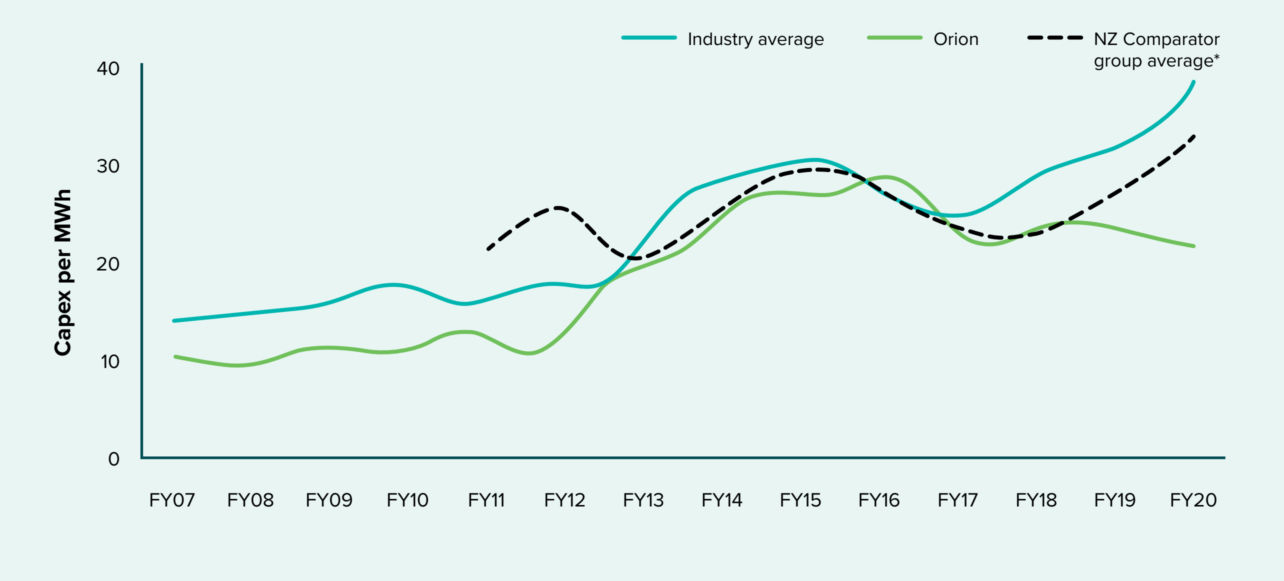
- capital expenditure per annum per MWh of electricity supplied to customers
- operating expenditure per annum per MWh of electricity supplied to customers
- operating expenditure per annum per year end number of ICPs (connection points)

Economic efficiency reflects the level of asset investment required to provide network services to customers, and the operational costs associated with operating, maintaining and managing the assets. There are inherent limitations when comparing performance with other EDBs. A direct comparison of data cannot be made appropriately without a full understanding of the local context, asset history, and business purpose and drivers of each EDB being compared. For this reason the comparisons provided below are for guidance only.

4.5.5.1 Capital expenditure per MWh

Figure 4.5.6 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. Despite this our capital expenditure remains aligned with that of both the industry average and the subset NZ comparator grouping. The industry average and the subset NZ comparator show an increasing trend of capital expenditure from FY17 while our expenditure levels off. This is reflected in this AMP as we move into a less capex intensive period only subject to the rebuild of the central business district which has occurred at a slower and more measured rate than initially anticipated in 2011.

Figure 4.5.6 Comparing Capex per MWh and industry performance



* Wellington Electricity, WEL Network and Unison

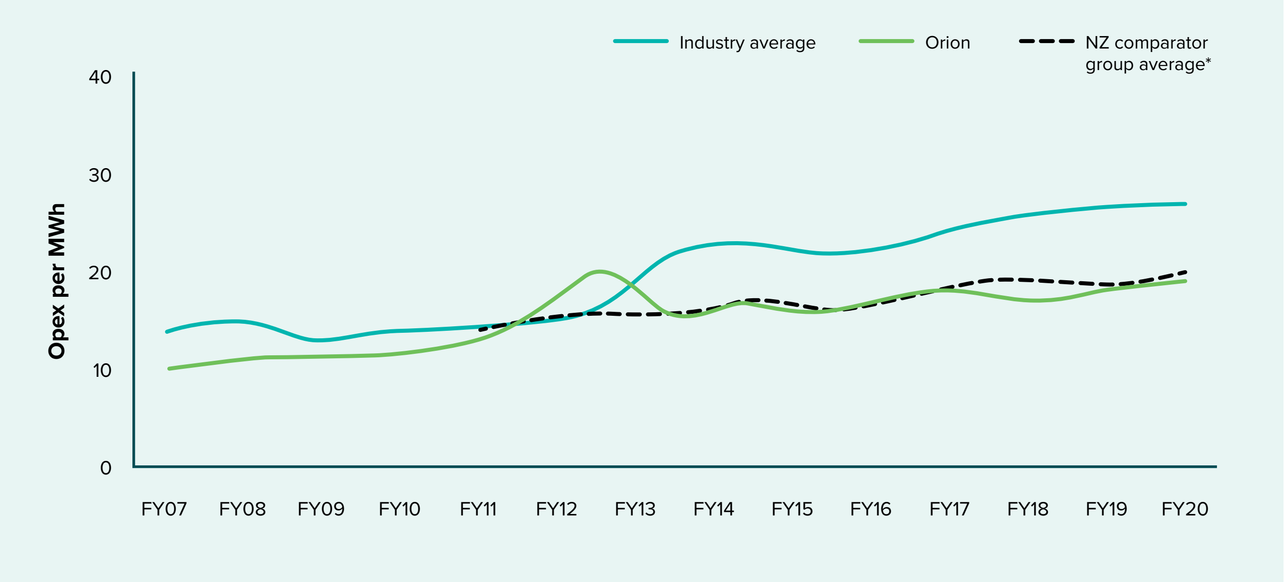
4.5.5.2 Operational expenditure per MWh

Figure 4.5.7 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. Our expenditure forecasts reflect this. We are moving into a period of asset management continual improvement linked closely to customer expectations. As a balance to this we ensure our service provider workload is set at sustainable levels that match our resource availability.

Figure 4.5.7 Comparing Opex per MWh and industry performance



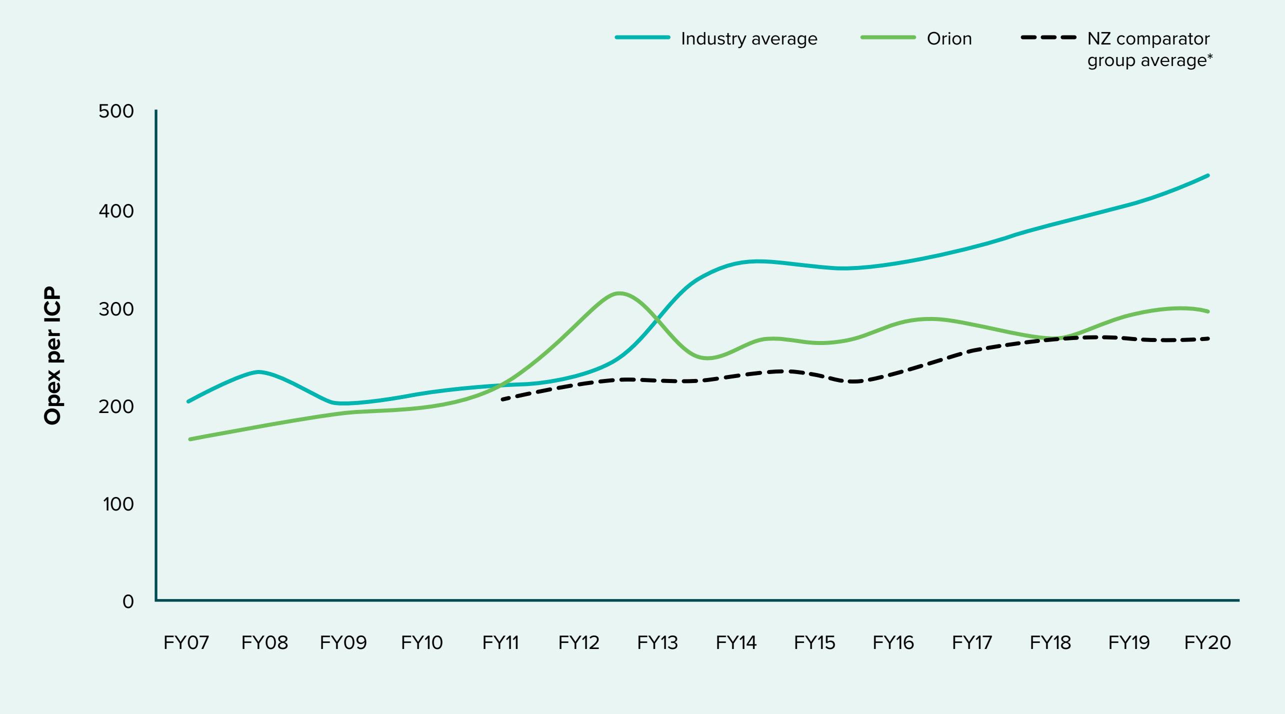
* Wellington Electricity, WEL Network and Unison

4.5.5.3 Operational expenditure per ICP

Figure 4.5.8 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.

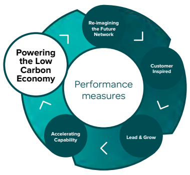
Overall we are proud of our performance and feedback from our customer engagement tells us we are meeting our customers' service expectations. We are focused on our Purpose to power a cleaner and brighter future for our communities. The industry average follows a similar upward trend but at a notably 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 207,500 at the end of FY20. Our customer base continues to increase, gradually bringing us into close alignment with the subset NZ comparator grouping at FY20.

Figure 4.5.8 Comparing Opex per ICP and industry performance



* Wellington Electricity, WEL Network and Unison

4.5.6 Powering the Low Carbon Economy

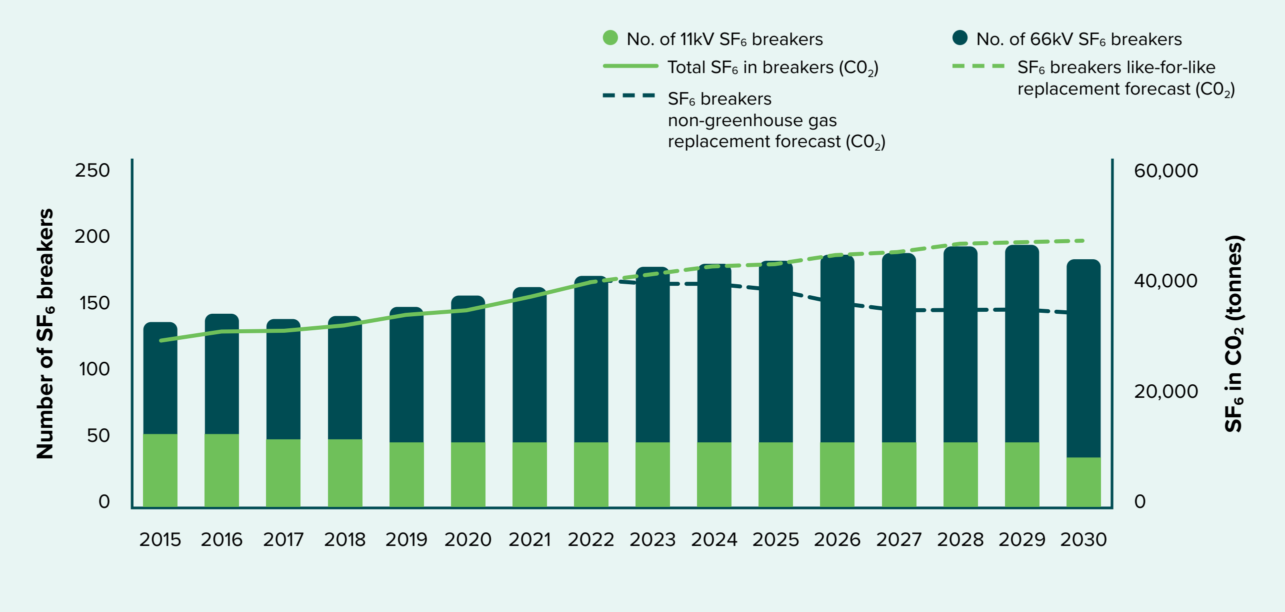


We are a passionate advocate for clean energy, and a proactive enabler of those seeking help to reduce their carbon footprint through more efficient use of low carbon energy sources. Our service is vital to the wellbeing and livelihood of the people and businesses in our region. This responsibility drives us to understand more about the impacts of climate change on our operations, so our network and our business can continue to be safe, reliable and resilient.

We have two initiatives to reduce our carbon footprint by minimising Orion's SF_6 emissions and protect the environment in the operation of our network. They are:

- **The amount of SF_6 gas lost into the atmosphere as a percentage of the total volume in use on our network.** Sulphur hexafluoride (SF_6) is a potent greenhouse gas (1kg of SF_6 is equivalent to 22,800kg of CO_2) used under pressure as an electrical insulator and arc suppressant in circuit breakers rated 11kV and above. We have 48 (3%) 11kV circuit breakers that use SF_6. It is now our practice to avoid the use of SF_6 at the 11kV and 33kV voltage levels to minimise the potential environmental impact that SF_6 can cause should it leak into the environment. There are few options for non-SF_6 dead tank 66kV circuit breakers available in the market, and we are actively seeking one for new and replacement installations from 2022 onwards. Figure 4.5.9 shows our forecast for the quantity of potential SF_6 in-service circuit breakers in use on our network as well as the CO_2 equivalency. The gap between the two projection lines demonstrates the potential reduction that could be achieved if we use non-greenhouse gas insulated circuit breakers.
- **The number of oil spills that are not contained by our oil containment facilities or mitigation procedures.** We operate oil containment facilities and have implemented oil spill mitigation procedures and training. Our target of zero uncontained oil spills is the only prudent target we could have for this measure.

Figure 4.5.9 Forecast for SF_6 circuit breakers



4.5 Performance measures continued

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, below the regulated target of 1%. In FY20 we engaged a service provider to assist us to manage and record our SF_6 stocks. This has led to improved recording of our actual losses. For this reason, in FY20 we did not achieve our target loss figure as shown in Table 4.5.6.

Due to our reporting obligation to the Ministry for the Environment, our current target is measured as a percentage of SF_6 loss. In the future we will set a quantity based target that will provide a clearer representation of our commitment to reduce SF_6 over out network.

Table 4.5.6 Sustainability performance against target

Measure	FY20 Target	FY20 Performance	FY21-FY25 target
SF_6 gas lost	< 0.8% loss	0.86% loss*	< 0.8% loss
Oil spills (uncontained)	0	1	0

* Calendar year performance for 1 Jan 2019 to 31 Dec 2019

Regarding oil spills, during FY20, we had an incident where the flooding of the Rakaia River washed away a transformer pole close to the bank. Oil was spilt as a result, and we did not meet our target of zero uncontained spills.

5

About our network

8,000	Square kilometres network coverage
11,500	Kilometres of lines and cables
50	Zone substations
390	Major customers with loads from 0.2MVA
90,000	Orion power poles
11,700	Distribution substations

Photo: Akaroa harbour, seen from a farm above Duvauchelle Bay.

Contents

5.1 Introduction

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

5.2 Transpower Grid Exit Points (GXP)

Our network is supplied from seven Transpower Grid Exit Points (GXP) at substations as shown in Table 5.2.1. The three remote GXPs at Coleridge, Arthur's Pass and Castle Hill each have a single transformer and a much lower throughput of energy.

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 relays. They are covered by an Access and Occupation Schedule Agreement with Transpower.

Transpower charges users, for example Orion and MainPower, for the costs of upgrading and maintaining GXPs. Orion owns all the assets connected to the 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

GXP	Customers %
Islington	70%
Bromley	27%
Hororata	2%
Coleridge, Arthur's Pass, Castle Hill and Kimberley	1%

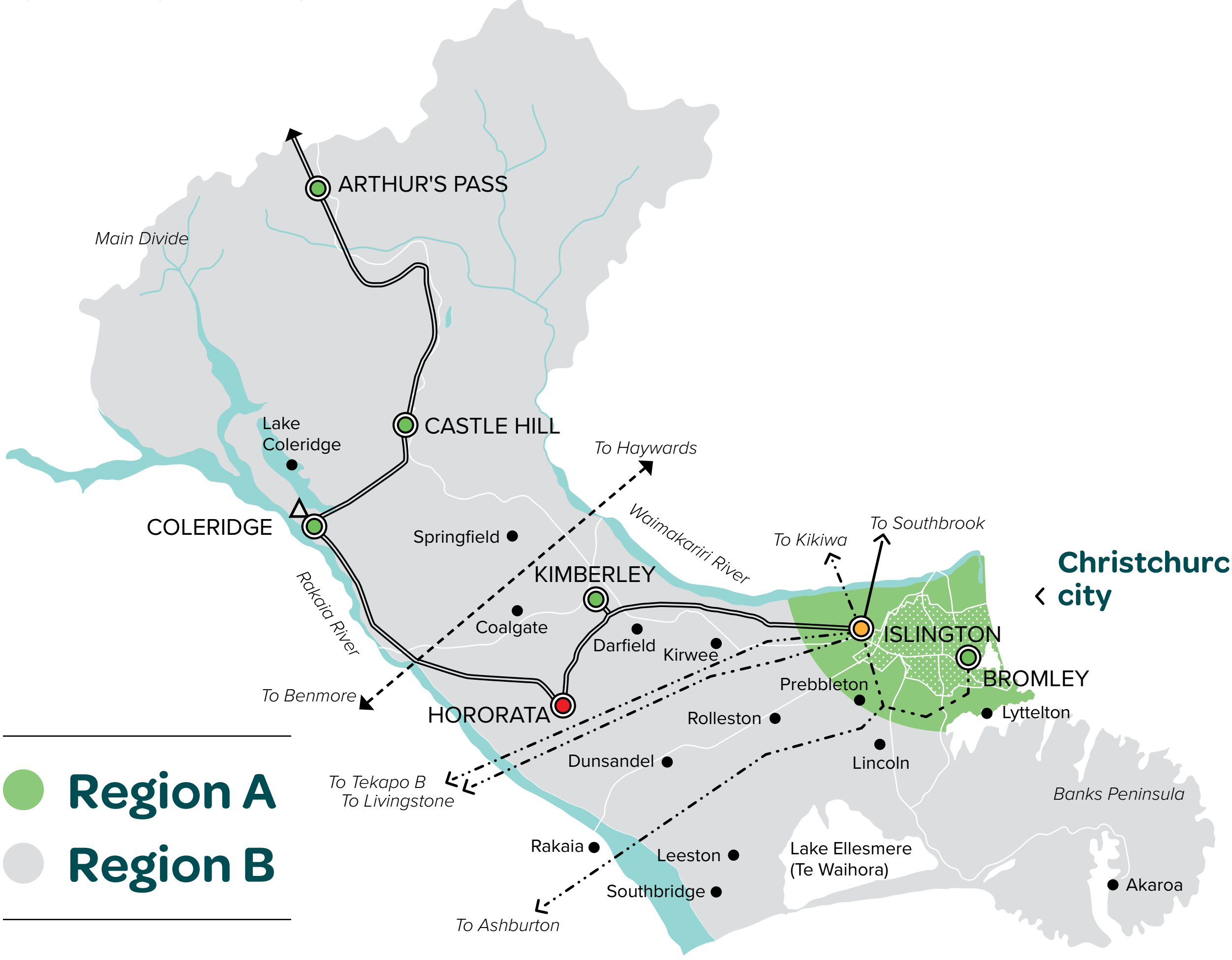
The Islington GXP supplies 70% of our customers. As the number of customers reliant on the Islington GXP grows, we will work with Transpower to overcome the risks associated with being highly dependent on one GXP by increasing capacity at other GXPs. Orion's network serves a diverse range of customers, 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

Region B – Banks Peninsula, Selwyn district townships

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 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 Region A GXPs

As shown in Figure 5.2.1 Region A GXPs are located at Islington and Bromley and supply the Central Business District, Lyttelton and the Christchurch city 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.

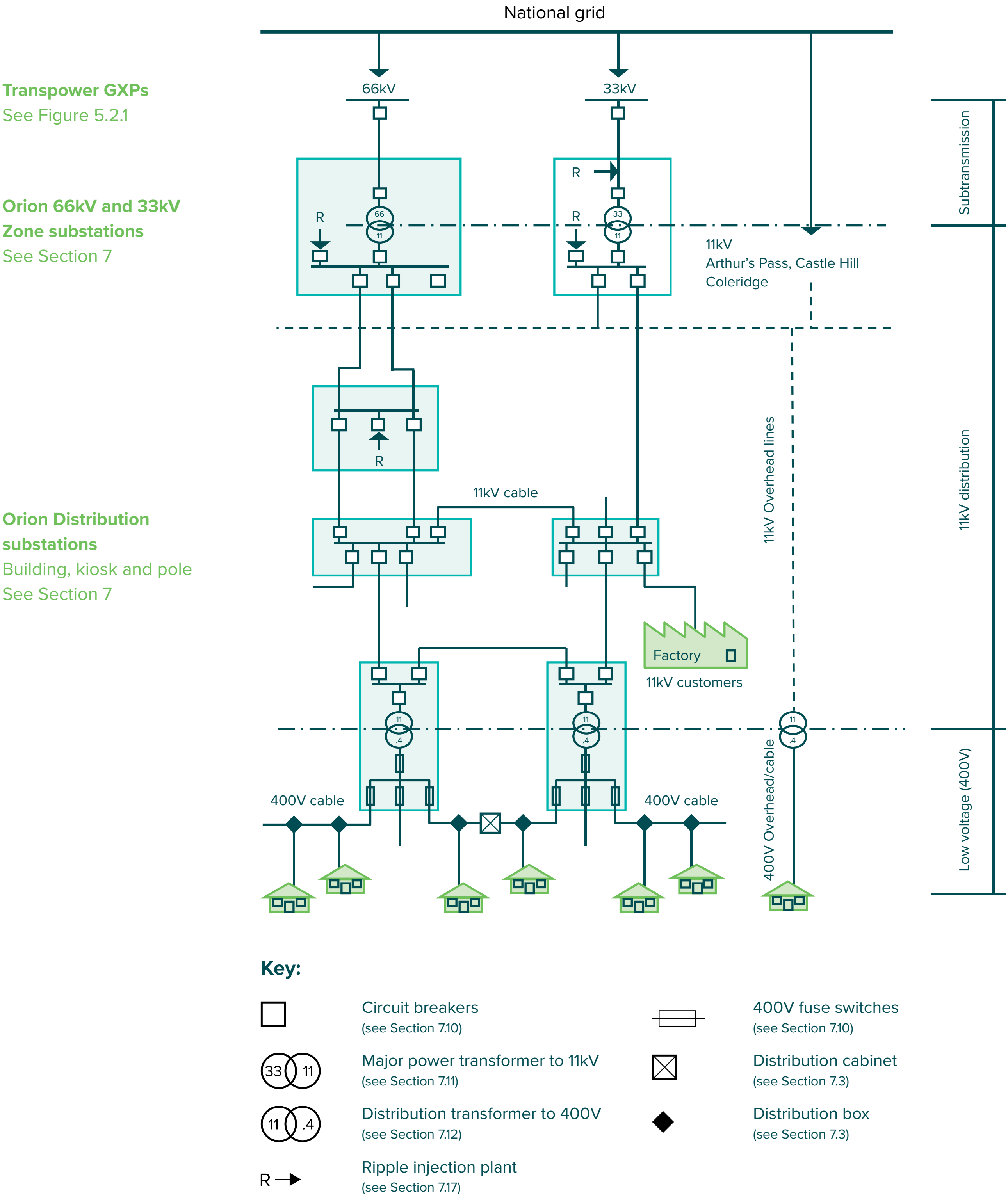
5.2.2 Region B GXPs

Islington GXP also supplies a large part of the Region B network including Banks Peninsula and the Rolleston and Lincoln townships. Hororata and Kimberley GXPs supply a significant proportion of the summer irrigation load and milk processing area. 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. 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.

5.3 Network architecture

Approximately 85% of our customers are in Region A with the remaining 15% in Region B. Figure 5.3.1 shows an overview of our network architecture.

Figure 5.3.1 Network voltage level and asset relationships



5.4 Major customers

Orion has approximately 397 customers with loads of at least 150kVA 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. We also provide incentives for major customers to run embedded generation. This enables us to manage load during network maximum demand times.

Although there are issues to be co-ordinated when sites with generation are established, there is minimal impact on the operation and asset management of the local area network. See Section 6.4.5.1 for details of our customer demand management initiatives.

Our major customers operate across a range of industries and sectors as shown in Table 5.4.1.

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

Table 5.4.1 Major customers by load size

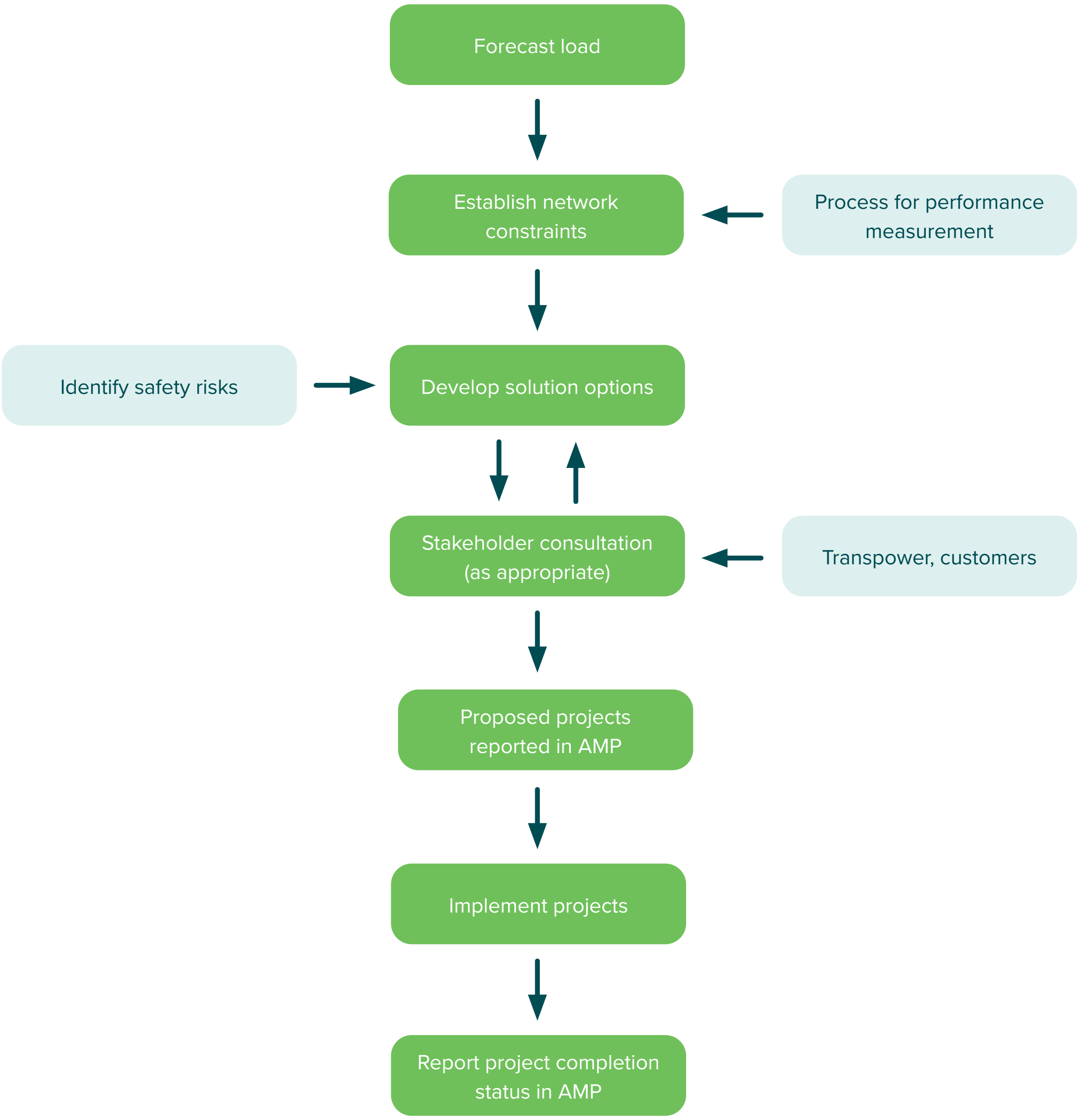
Load	Industry/Sector	Number	Notes
≤ 2MVA	All	~380	Includes heavy manufacturing, hotels, water and wastewater pumping stations, prisons, retail and businesses.
> 2MVA	Food processing	7	The Synlait Milk plant at Dunsandel was commissioned during 2008. It required a new zone substation at Dunsandel to provide enhanced security. In 2018 Orion worked with Synlait to support their installation of New Zealand's first large-scale electrode boiler as part of its strategy to significantly reduce its environmental impacts. The Darfield Fonterra plant commissioned during 2012 required a new zone substation (Kimberley).
	University	1	
	Shopping mall	2	
	Hospital	2	
	Airport/seaport	3	As part of 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	

5.5 Network development approach

We plan our network using a network development process which is informed by the needs of our customers. It is based on the following criteria: our Security of Supply Standard, network utilisation, forecast load compared with network capacity and non-network solutions. This process benefits our customers because it allows us to balance the growth needs of the community and new connections while ensuring appropriate levels of reliability and security for all customers. Further details on our approach to planning and specific planning criteria are set out in Section 6.4.

We plan our network using a network development process which is informed by the needs of our customers.

Figure 5.5.1 Process for network development



5.5 Network development approach continued

When a network issue is identified, for example a safety risk, capacity or security of supply gap, the process of developing solutions begins. We consider different options to address the gap which may include both traditional and non-traditional solutions such as customer demand management or distributed generation. We also consider whether the solutions comply with our design standards including safety objectives, capacity adequacy, quality, reliability, security of supply and economic consequences. Further details of our network planning criteria are set out in Section 6.

Once we have established the way forward, we go through a project prioritisation process. There we look at how we can best schedule projects to fit in with NZ Transport Authority and local authority projects, meet customer expectations, consider service provider resource constraints and align with our asset replacement and maintenance programme. More detail on our project prioritisation process is described in Section 6.4.4.

Once we have established the way forward, we go through a project prioritisation process.

5.6 Asset lifecycle management approach

Our engagement with customers as described in Section 4 tells us that our customers want us to maintain a safe, reliable, and increasingly resilient network. We deliver this by managing our assets using an asset lifecycle management approach (Figure 5.6.1) which includes asset maintenance planning using reliability centred maintenance (RCM) and maintenance and risk management techniques. Throughout this process we balance our shareholder and customer needs today, and into the future. 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. Benefits of a whole of life approach are:

- minimising safety risks and future legacy issues through safety in design
- understanding capex/opex trade-offs
- establishing forecasts for operational and replacement expenditure, thus avoiding surprises
- minimising the total cost of ownership while meeting accepted standards of performance

The steps we take through our lifecycle asset management approach are described in the diagram to the right.

Throughout this process we balance our shareholders' and customers' needs today, and in the future.

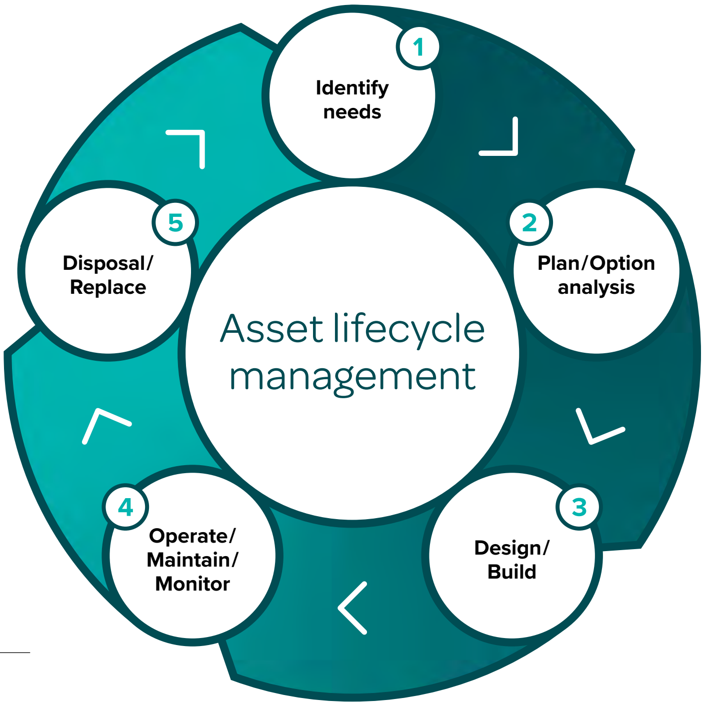


Figure 5.6.1 Asset lifecycle management approach

5.6.1 Identify needs

The first step in the asset lifecycle management process is to identify needs. This is based around two main areas – setting service levels and measuring service levels.

5.6.1.1 Setting service levels

Service level requirements are largely informed through customer consultation, health and safety considerations and regulatory requirements. Further details on how our service levels are set and the levels we are currently working to are detailed in Section 4.

5.6.1.2 Measuring service levels

In this step, we review how we measure service levels for SF_6 and SAIDI and SAIFI.

A small amount of our circuit breakers use SF_6, a greenhouse gas, as the interruption medium. We measure the loss of SF_6 to the atmosphere on an annual basis. Our SF_6 loss measurement is based on the quantity of top up gas that is added to the breakers or discharged from storage. Top up gas bottles are weighed pre and post top up. All gas movements are recorded and sent to us for logging.

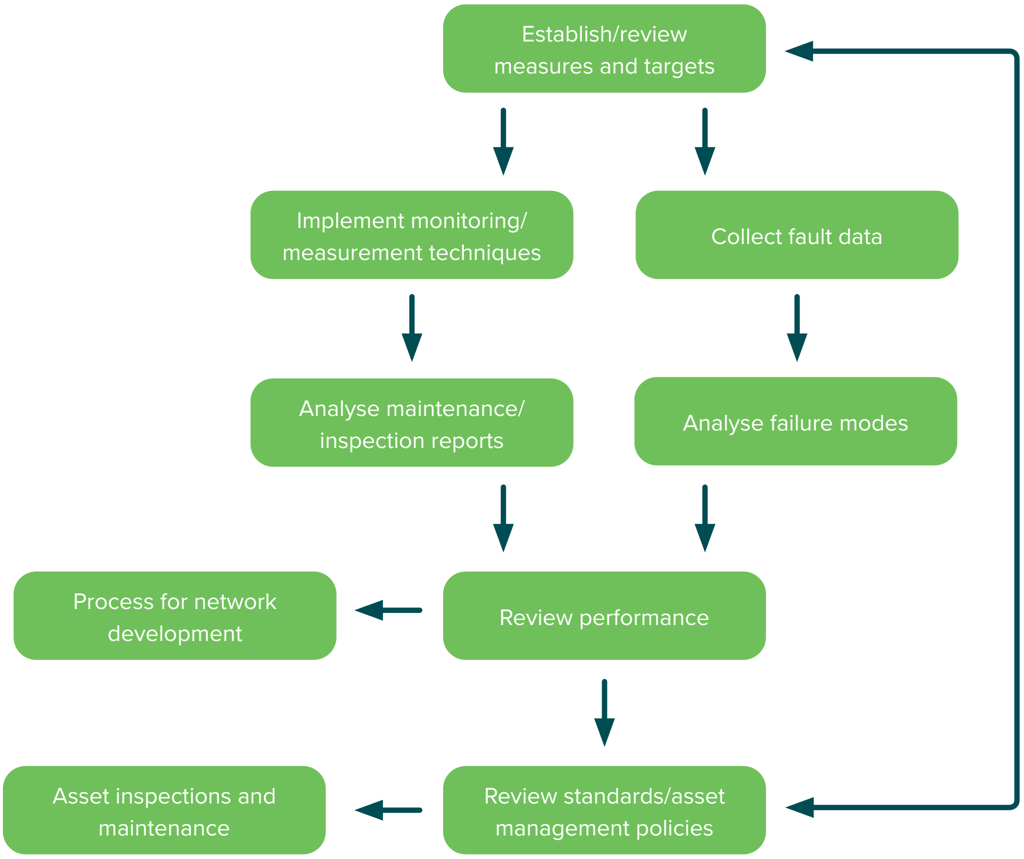
We are obligated to report and surrender a payment based on the unit of emission. For service level performance against targets, see Section 4.5.

We collect network performance data on duration and frequency of all network outages (SAIDI and SAIFI) logged in our control centre. The data collection process has been automated with the introduction of our network management system that utilises Supervisory Control and Data Acquisition (SCADA) information and a real-time network model.

This process is independently audited on an annual basis. SAIDI and SAIFI figures are monitored and reported on a monthly basis to allow appropriate management of the network.

A more detailed internal review of network reliability is undertaken on an annual basis. This review is documented and includes root-cause analysis of asset downtime and failure modes. This includes analysis of asset failure trends. Our assessment of service level performance is used to inform our standards and asset management policies, our network development, replace, maintain and disposal plans, and asset inspection regime. Figure 5.6.2 gives an overview of our process for performance measurement.

Figure 5.6.2 Process for performance measurement



5.6 Asset lifecycle management approach continued

5.6.2 Planning and options analysis

Based on what needs are identified, we then move into the planning stage. During this stage of the lifecycle process, we develop the replacement plan and the maintenance plan.

5.6.2.1 Replacement plan

A number of techniques are used to ensure 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 which is 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. Table 5.6.1 provides a summary of the asset management approach for each asset category.

Our current approach is based around the following:

- high value assets or assets with a high consequence of failure – predominantly condition based replacement based on robust inspection, testing and failure rate
- other assets are age or condition based replacement as appropriate
- voluminous assets with an individual low cost and low consequence of failure – run until non-operational, with limited inspections that are focused on identifying damaged assets that represent a safety or environmental risk
- substation buildings and kiosks are maintained and repaired when required

Table 5.6.1 Asset management approach for asset class

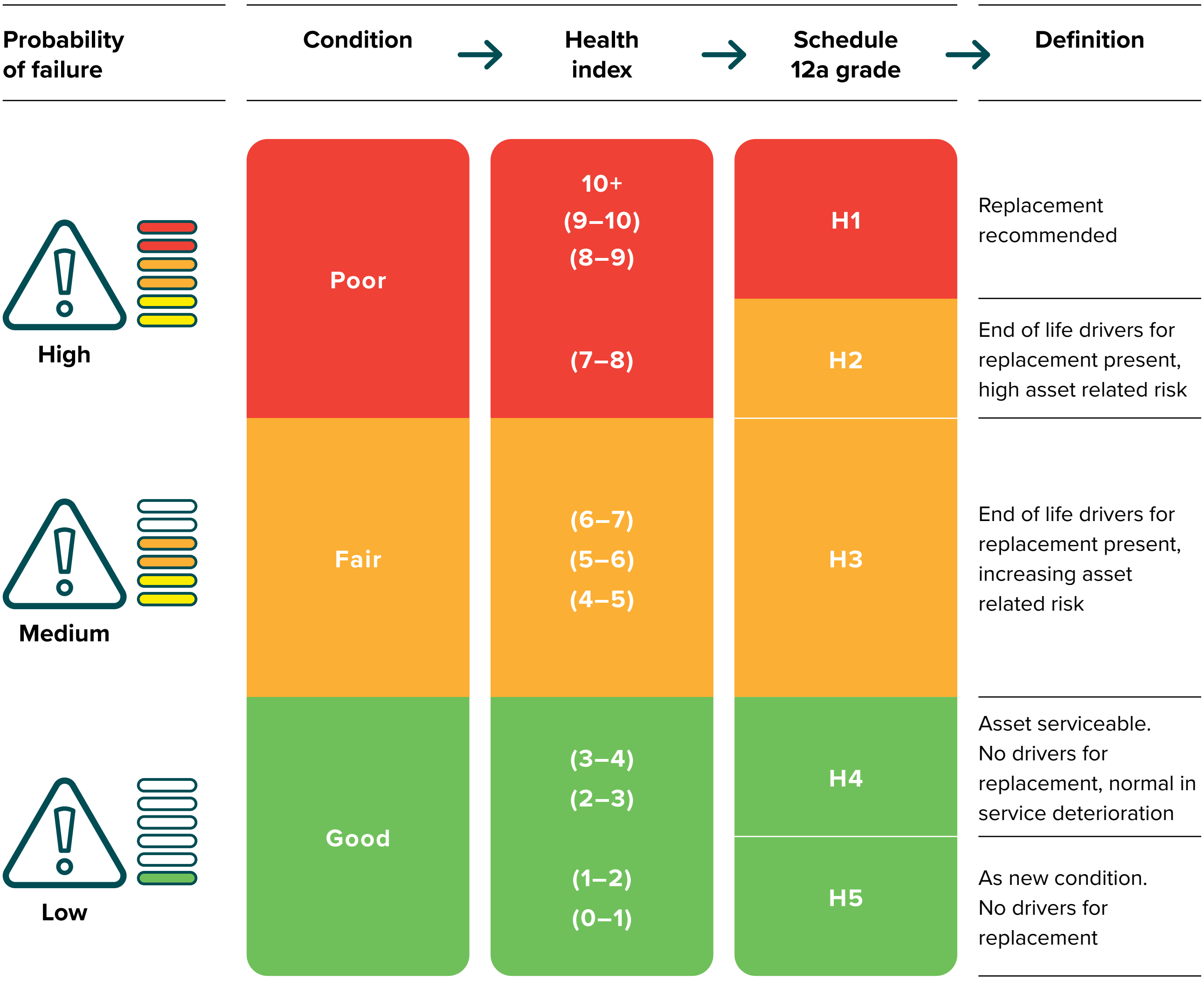
Asset class (arranged in order of FY22 capex high to low)	Tool	Predominant condition based replacement		Predominant age based replacement	Run to non-operational	Indefinite maintenance and repair
	Approach	CBRM model	Asset condition & performance	Asset data	–	Asset data
HV Switchgear & circuit breaker		✓				
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			✓			

Condition Based Risk Management Model

We have Condition Based Risk Management (CBRM) models for the majority of our 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 determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model is one of the tools used to inform our decision making for selected asset classes as part of building our asset replacement programmes. The CBRM models calculate the health index and probability of failure of each individual asset. It then takes into account the consequence of failure to finally assign the risk to that particular asset. Our health index scoring is different to the Commerce Commission grading system set out in Schedule 12a of the information disclosure requirements.

Figure 5.6.3 CBRM score conversion table



Probability of failure	Condition →	Health index →	Schedule 12a grade →	Definition
High	Poor	10+ (9–10) (8–9)	H1	Replacement recommended
		(7–8)	H2	End of life drivers for replacement present, high asset related risk
Medium	Fair	(6–7) (5–6) (4–5)	H3	End of life drivers for replacement present, increasing asset related risk
Low	Good	(3–4) (2–3)	H4	Asset serviceable. No drivers for replacement, normal in service deterioration
		(1–2) (0–1)	H5	As new condition. No drivers for replacement

Asset risk matrix

We have refined our approach to risk assessment for our portfolio assets by more explicitly showing health and criticality. As a result, we can now visually display through a risk matrix the level of risk attributed to each individual asset within an asset class and what intervention strategy is required. The risk matrix is used to identify which asset when replaced will provide the greatest reduction in the overall fleet risk profile.

As shown in Table 5.6.2, the inputs to the risk matrix are our **asset health index** and **asset criticality index**.

- **Asset criticality index** – evaluates how failure could have an impact on safety, network performance, financial and environment. As the consequences for the different categories are not the same, criticality weightings are applied to give a criticality score, ranging between C1 to C4 where C1 represents the most serious consequence
- **Asset health index** – ranges between H1 to H5 with H1 being the worst health. Asset health is calculated based on asset age and factors such as its installed environment and performance. The factors vary for different asset classes.

The resultant risk matrix provides a visual representation of risk for a fleet of assets and the risk grades are linked to the replacement strategy. The risk grade definitions for R1 to R5 are aligned to the EEA Asset Criticality Guide and our corporate risk guideline. See Section 7.6 for the application of the risk matrix for poles.

Table 5.6.2 Our risk treatment and escalation guidelines

Risk ratings	Definition		Strategy
R1	Extreme	Combination of high consequences of failure and reduced HI indicates high risk	Immediate intervention
R2	Very high	Combination of criticality and health indicates elevated risk	Schedule intervention
R3	High	Healthy but highly critical assets	Reduce consequence of failure
R4	Medium	Typical asset in useful life phrase	Monitor and maintain
R5	Low	Low relative consequence of failure	Tolerate increased failure rate

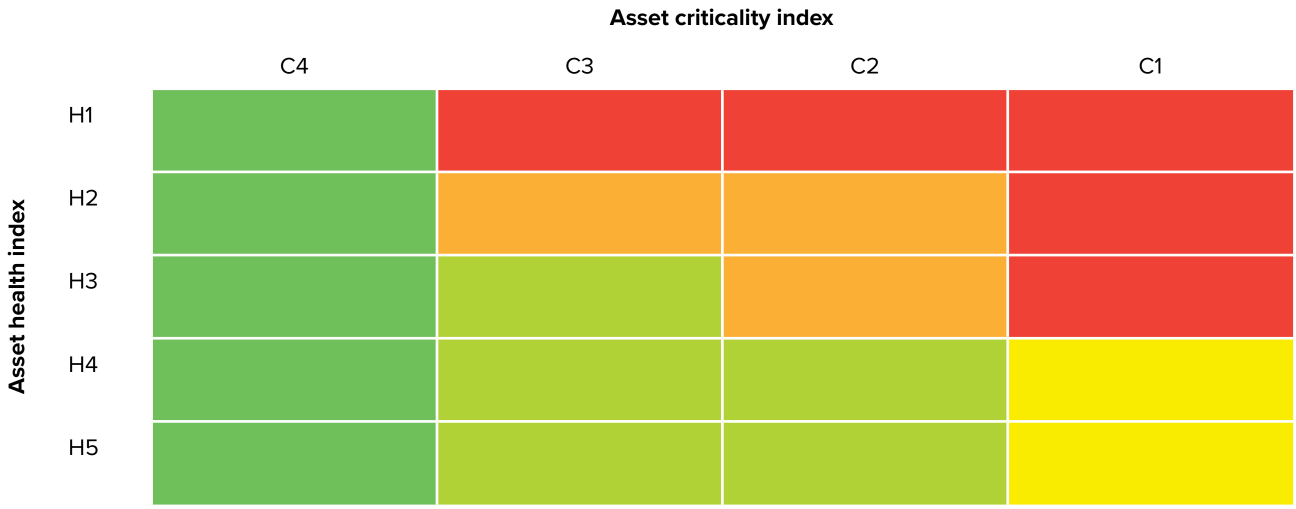
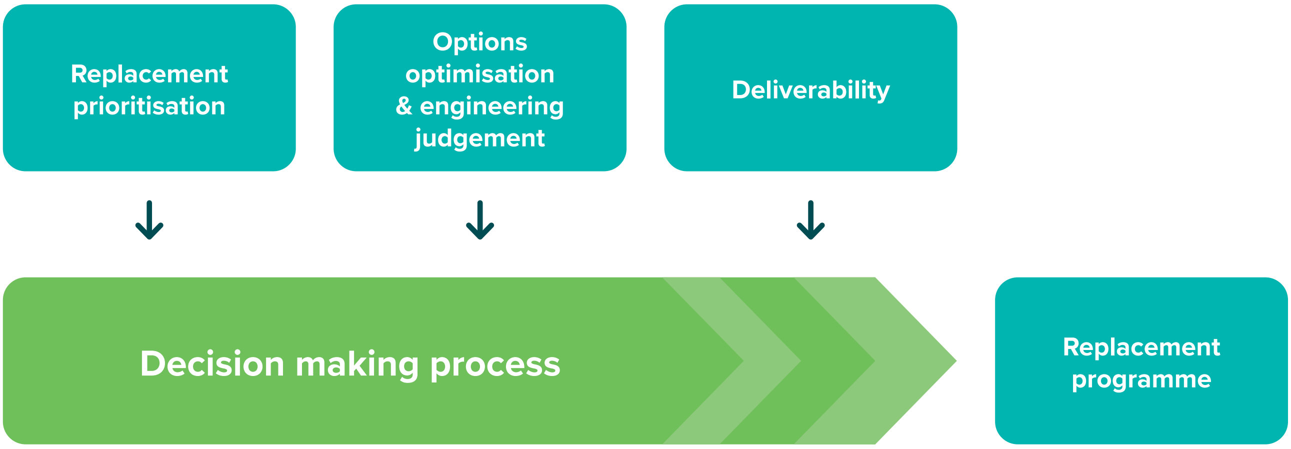


Figure 5.6.4 Replacement decision making process



Replacement prioritisation – is used to inform our decision making for selected asset classes as part of building our asset replacement programmes. This effectively gives the asset a ranking which can be used to help prioritise replacement strategies.

Options optimisation – one of the main options that we analyse for our asset replacement programme is around the timing of the replacement. This ensures that we are getting the best usage of our existing asset. The CBRM model can aid us in this process by creating scenarios, including ‘doing nothing’, that model the deterioration of asset condition giving us an indication of the additional risk that is imposed allowing us to then decide if this is acceptable and if this significantly affects our service levels.

When an asset is identified for replacement it is seldom a simple matter of replacing like for like. Internal review, analysis and planning are undertaken for the asset, its interaction with other equipment and its integration into the immediate network. This leads to a range of options to continually improve our asset, network operation, service levels and reduce overall cost. The options involve consideration of the following:

- 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
- can the timing be linked to other work on the substation, network or circuit to minimise outages and better utilisation of resources?
- suitability for future change in the network
- lifecycle cost and environmental impact

Deliverability – analysis is undertaken to determine if the work plan can be delivered. It should be noted that external influences could adversely or positively impact the delivery outcome. The number of units to be replaced can be affected by network constraints, resourcing issues and the overflow of uncompleted work from previous financial years. The objective is to smooth the works programme by deferring where we can but also by bringing replacement forward where appropriate. For more information on deliverability see Section 10.

5.6.2.2 Maintenance plan

Our network maintenance philosophy is reliability-centred and based on retaining a safe asset function. The majority of our assets are subjected to a routine time based programme of inspections, maintenance and testing. However, for our high value assets with high consequence of failure we also undertake a reliability based programme where the frequency and activities are tailored according to the performance and condition of each asset. This is considered a cost effective option for this type of asset as replacement is very costly, however maintaining reliability is critical as an asset failure has a high impact on service levels and other objectives. The detailed asset management activity of each asset class and the equipment within the asset class are described in the relevant sections of this AMP and also in our associated internal Asset Management Reports.

We have specific maintenance programmes for each of our asset classes however all works generally fall into the following categories:

- **Scheduled maintenance** – work carried out to a predetermined schedule and allocated budget
- **Non-scheduled maintenance** – work that must be performed outside the predetermined schedule, but does not constitute emergency work
- **Emergency maintenance** – work that must be carried out on a portion of the network that requires immediate repair

5.6.3 Design and build

We use service providers for the design and build of projects identified in the AMP. Through this process, we use a number of key standards and specifications that are set out below.

5.6.3.1 Safety in Design

We have developed a Safety in Design process that can be applied at any stage of asset lifecycle and can also be applied to non-network assets such as vehicles, tools and innovation. The Safety in Design standard is used by us and approved service providers to identify hazards that could exist throughout the complete lifecycle of assets from concept to disposal via construction, operation and maintenance. The standard includes a hazard identification and risk assessment process which, when applied by designers and other key participants such as those who construct and operate the assets, proposes elimination and control measures for each identified hazard to a level so far as is reasonably practicable. The Safety in Design process aligns with industry best practice and ensures designers carry out their duties in line with the Health and Safety at Work Act 2015.

This innovation delivers on two areas of focus in our asset management strategy:

- continually improving to provide a safe, reliable, resilient system
- maintaining our health and safety focus

Customers benefit as a result of the equipment we install being designed in a way that protects public safety, minimises customer outages and enhances system resilience in adverse events.

5.6.3.2 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 approved 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.

5.6.3.3 Technical specifications

Technical specifications are intended for authorised service providers working on the construction and maintenance of our network and refer to the relevant codes of practice and industry standards as appropriate. Specifications are listed in Appendix D against the asset group they relate to.

5.6.3.4 Equipment specifications

We also seek to standardise equipment used to construct components of our network. To this end 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.

To manage the health and safety, cost, efficiency and quality aspects of our network we standardise network design and work practices where possible.

5.6.3.5 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. We create a new operating instruction each time any new equipment type is introduced. See Figure 5.6.6 – Process to introduce new equipment.

5.6.3.6 Operating standards

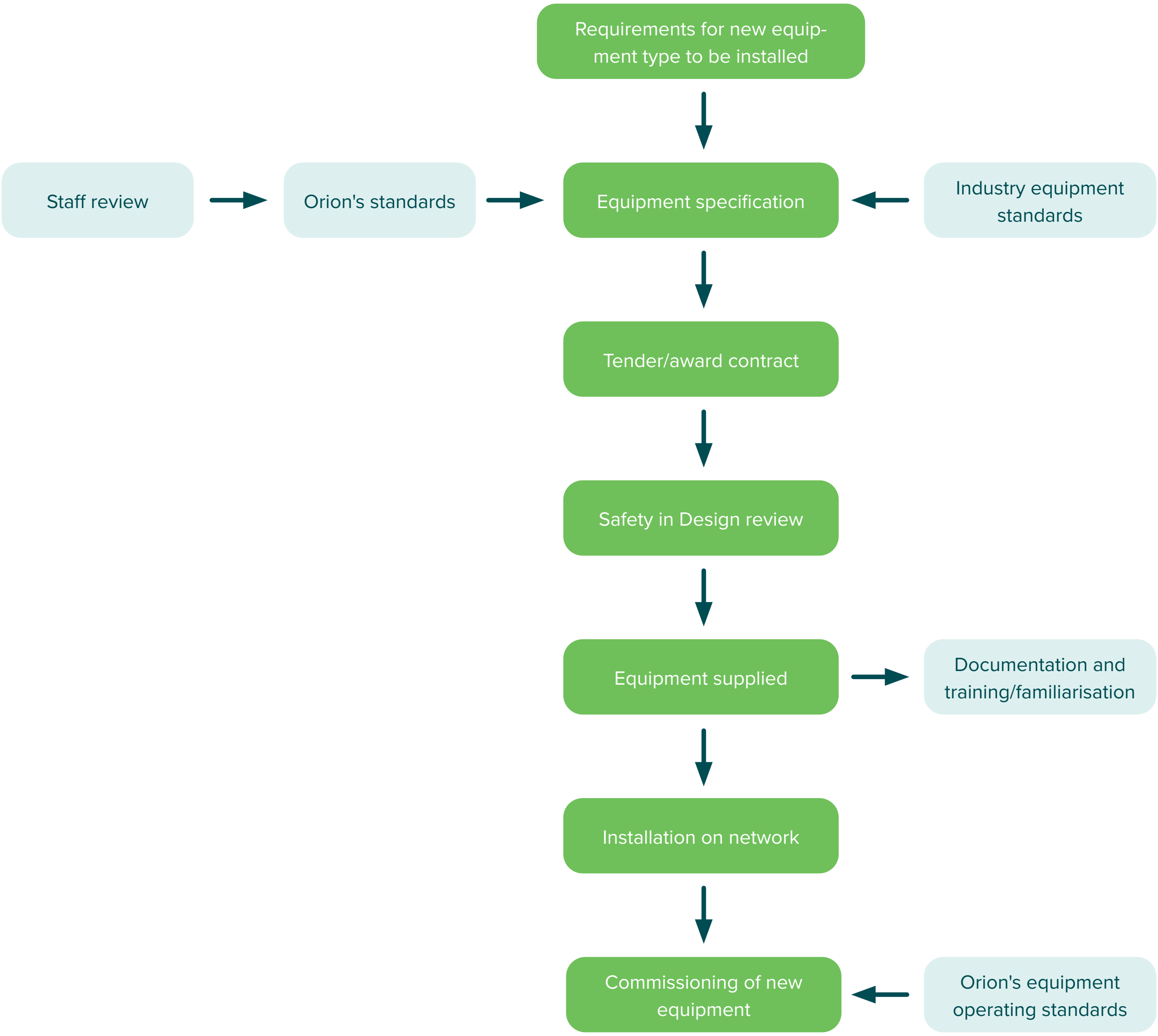
To ensure our network is operated safely we have developed standards that cover such topics as the release of network equipment, commissioning procedures, system restoration, worker training and access permit control.

5.6.3.7 Document control process

To ensure our documentation and drawings are maintained as accurately as possible, each is 'owned' by one person who is responsible for any modifications to it. Our Asset Data Management team is responsible for processing these controlled documents using a process set out in our document control standard. This standard also defines a numbering convention used to identify our documents based on the type and assets covered. This approach assists in searches for relevant documents.

Email and a restricted-access area on our website are used to make documents and drawings accessible to approved service providers and designers.

Figure 5.6.5 Process to introduce new equipment

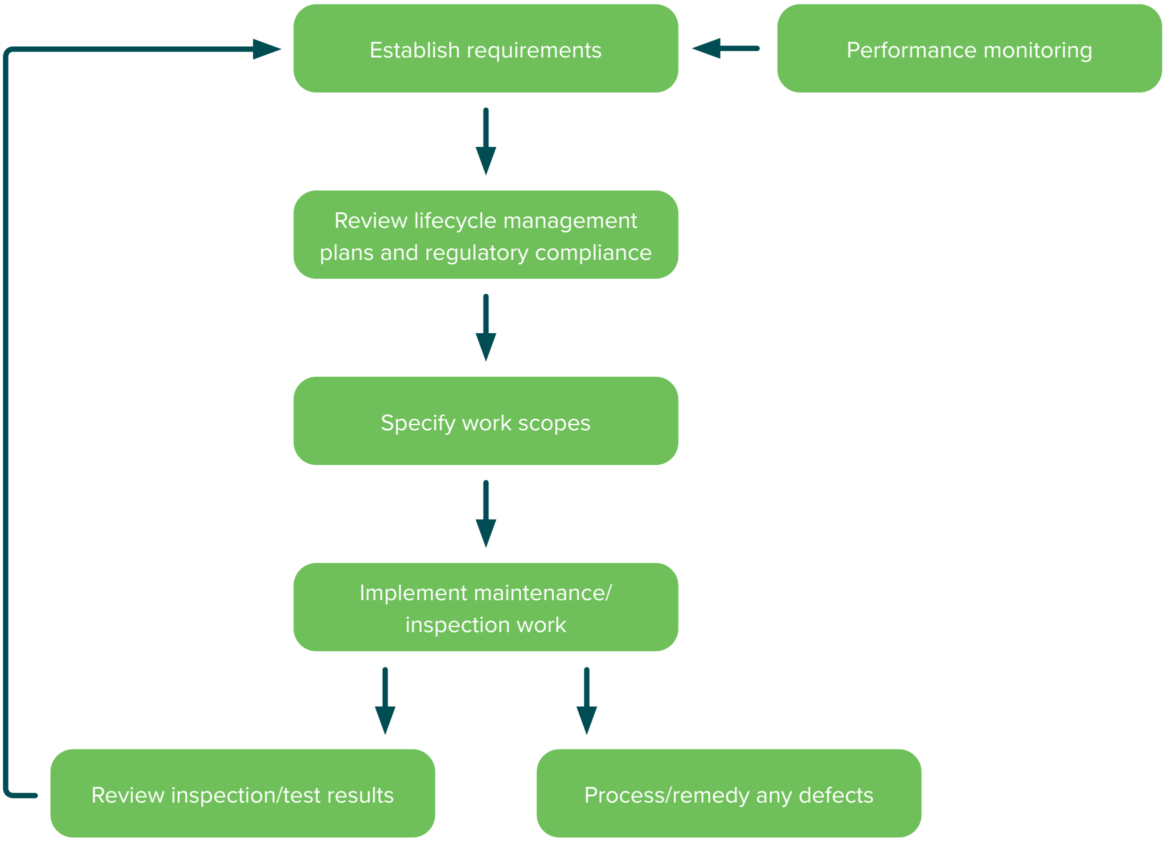


5.6 Asset lifecycle management approach continued

5.6.4 Operate, maintain, monitor

The operate, maintain, monitor 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 a competitive tender process to contract out all works. Monitoring of assets is against the service levels defined in this AMP, but also against specific requirements of the asset class. The process is shown in Figure 5.6.6.

Figure 5.6.6 Process for routine asset inspection and maintenance



5.6.5 Disposal and replacement

Disposal and replacement 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 7 under disposal plan.

5.7 Investment and business case framework

We develop business cases for near term projects with different options for solving system issues and meeting customer need. Business cases support our network development and complex lifecycle management capital projects, and Asset Management Reports (AMRs) support our lifecycle management portfolio programmes of work. Business cases are often underpinned by an overarching business case which addresses our security of supply architecture standards.

Our infrastructure team and other relevant support people along with our leadership team provide internal peer review and challenge to these business cases and AMRs. We also share our thinking and a selection of business cases with our leadership team and board where they meet defined investment thresholds for approvals under our investment and business case framework.

Further detail about the areas we consider in our network development approach and our planning criteria can be found in Sections 5.5 and 6.4; and the asset lifecycle management approach is explained in Section 5.6. Orion uses an asset planning decision framework and options assessment approach to decide the complexity of a business case based on the network project type proposed. Table 5.7.1 provides a summary of the assessment level decision framework.

Table 5.7.1 Assessment level decision table

	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
Principle 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, replacement / reinforcement	Weighing up options to improve reliability, resilience, future network, replacement / 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

6

Planning our network

Photo: View to Christchurch city at dusk, taken from Sumner.

Contents

6.1 Introduction

In this section we set out how we plan 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 the challenges and opportunities posed by an era of rapid technology change in our industry.

Towards the end of this section we detail the proposed projects our planning process has identified are needed to maintain and increase the safety, reliability, resilience and sustainability of our network over the coming ten years.

Our capital expenditure keeps pace with the growing demand on our network. This growth is both in terms of the number of customers we serve, and energy demand.

We continue to experience steady growth in the number of residential customers moving into new housing developments in the Selwyn District and Halswell area. For example, at present the population of Rolleston sits at around 17,000 and is predicted to jump to more than 27,000 within a decade. Growth in industrial parks also continues as businesses take advantage of new energy efficient premises with easy access to road and rail.

To support this growth, we have planned significant projects. Some examples of these are:

- a new Region B GXP at Norwood to support growth in Selwyn District and western Christchurch
- a new Region B zone substation near Rolleston to support load growth in Rolleston and shift load from Islington GXP to Norwood GXP
- an upgrade of the Halswell zone substation capacity to support residential load growth in the southwest of Christchurch

At Orion, we are committed to powering a cleaner and brighter future for our communities. Key to this is ensuring our customers can take advantage of new low-carbon technologies and providing them greater freedom to manage their energy use to achieve their decarbonisation goals.

We will continue to lead and encourage our customers to adopt low-carbon technology, particularly for process-heating and transportation, where the biggest emission-reduction gains can be made. We aim to provide a safe, reliable open-access network where customers can connect any compliant load, storage or generating device and use our network as a platform for services to other connected customers.

At Orion, we are committed to powering a cleaner and brighter future for our communities.

In addition to this, we are seeing increased interest in new types of Distributed Energy Resources (DER) such as solar panels, wind-turbines, battery storage and electric vehicles. DERs are technologies that can generate or store energy at a customer level. They challenge the traditional approach to network operation and planning which assumes larger centralised power supplies which feed one-way to our customers. In contrast, DERs can change power flows from single to multi-directional which places additional demands on our low voltage networks which were not originally designed for this type of operation.

To meet these challenges, we are implementing initiatives that increase our knowledge of the network and systems that can fully utilise the data sources at our disposal to optimise the planning and operation of our network. Thus, enabling us to distribute clean, reliable and affordable power for the benefit of our customers and our region through our open-access network.

6.2 Evolving our network

The existing electricity business model is largely uni-directional. Large generators sell their production in the wholesale market, and the electricity is then distributed to end user customers, via the transmission network and lines companies such as Orion. This traditional one-way model is undergoing change for several reasons. These include:

- **Distributed Energy Resources (DER)** – 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
- **advanced digital technology** – will enable greater information access and management options at household and business levels
- **new consumption patterns** – adoption of EVs, other low carbon initiatives and other new technologies will create new challenges due to their increased demand for energy with less predictable behaviour

With these developments, and others that will emerge, our customers may increasingly wish to:

- sell surplus power to the grid
- store own-produced electricity for their future consumption and cost savings
- sell power on a peer-to-peer (P2P) basis to others
- develop virtual storage in neighbourhood networks
- charge their electric vehicles, and other flexible usage devices, at times when electricity pricing is lowest
- ramp back power usage at times when New Zealand's generation is operating from non-renewable sources

Customers will have many choices for investment and how to make the best use of the options open to them. We will continue to develop our understanding of what our customers want from us and how this translates to services they need. Regardless of the direction our customers and the market take, we will invest in new systems and technologies to deliver future customer benefits over our AMP planning period.

6.2.1 Developing our LV capability

Historically, LV networks were planned for reasonably stable passive household loads with one-way power flow. However, more customers are adopting technologies such as EVs which can place significant additional demand on a street's LV system. Given Orion's LV networks supply most of our residential customers, developing the visibility and capability of these networks is becoming increasingly important to efficiently manage our networks and facilitate customer choice.

We will continue to develop our understanding of what our customers want from us and how this translates to services they need.

We have four LV initiatives currently ongoing:

- LV feeder monitoring
- Smart meter information gathering
- LV network reinforcement, when identified as necessary
- LV research

These initiatives will develop our LV networks and help us to:

- provide information to guide our operational, planning and investment activities
- develop improved forecasting and modelling techniques for the future
- 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 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

6.2.1.1 LV feeder monitoring

In FY20, we began a 10-year programme to install monitoring at around 35% of our distribution transformers. Sites were prioritised based on a wide range of criteria such as those with high customer numbers, long overhead feeders and solar connections, as well as those which fell under our existing renewal programmes. Analysing the data from these monitors will enable us to develop a better understanding of LV demand as new technologies and customer behaviours become more prevalent. In the long-term, we aim to use this data to monitor trends and demand profiles at the LV level to inform our investment decisions.

In FY20, we completed 100 LV monitor installations and our LV monitoring program will continue to ramp up gradually over the 10-year AMP period. This rate of installation may vary depending on changing customer requirements, internal system capability and speed of adoption of new technologies.

In collaboration with the Electric Power Engineering Centre (EPECentre) at the University of Canterbury, we commissioned a high-level analysis to identify potential LV issues down at the distribution substation level. See Section 6.2.1.4. Our site selection for future LV monitoring installations will be informed by the outcomes of this research and our existing renewal programmes.

As more information is gathered and analysed, we will gain a fuller understanding of the community's adoption of new technologies and their impact on customer energy use. For example, in the UK, clustering of solar PV connections has been observed where 70% of solar penetration at household level occurs on just 30% of UK streets. This clustering effect is one of the reasons we need to increase our visibility and understanding of our low voltage network.

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).

6.2.1.2 Smart meter information gathering

While the LV feeder 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.

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

> **As more information is gathered and analysed, we will gain a fuller understanding of the community's adoption of new technologies and their impact on customer energy use.**

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 currently working with meter providers to obtain access to smart meter information and are hopeful this is achievable. An allowance for sourcing additional smart meter information has been incorporated in our operational expenditure.

6.2.1.3 LV network reinforcement

Based on LV modelling undertaken to date, we believe the majority of our low voltage network has sufficient capacity to meet demand in the short to medium term. However, as new technologies are adopted by more households and businesses, and as we receive more data on our low voltage network utilisation, it is expected reinforcement above historic levels will be required. We have revised our LV reinforcement budget to reflect this, based on results from our high-level modelling.

> **Based on LV modelling undertaken to date, we believe the majority of our low voltage network has sufficient capacity to meet demand in the short to medium term.**

6.2 Evolving our network continued

We will undertake network reinforcement through a portfolio of measures such as addressing phase imbalance, adding new transformers and installing new lines and cables. Where cost effective, we will also look at implementing non-traditional solutions to defer reinforcement such as static compensators (STATCOMs) or network batteries to provide reactive voltage support. In some cases, we may undertake greater Distributed Energy Resources Management, for example EV smart charging, to reduce peak load.

These innovations deliver on our asset management strategy focus on providing cost-effective solutions and embracing the opportunities of future networks.

6.2.1.4 LV research

In FY20, we commissioned a high-level study, in collaboration with EPECentre at the University of Canterbury, to forecast the potential impact of electric vehicles and residential batteries on the low voltage network. The study focussed on highly residential areas which are more likely to experience phenomena such as residential infill and EV clustering. This built on the preliminary constraint results published in our 2019 AMP by refining our network parameters and investigating a wider range of EV charging behaviour.

The four scenarios considered are:

- **Scenario 1** – Diversified EV load at peak (1kW/EV)
- **Scenario 2** – Undiversified EV load at 9pm (3kW/EV)
- **Scenario 3** – Diversified EV load at peak with battery support (1kW/EV and 4kW battery support from 5% of connections)
- **Scenario 4** – Undiversified EV load at peak (3kW/EV)

Constraints have been 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 have enabled us to identify LV networks which will be most vulnerable to load changes arising from the adoption of new technologies. Figure 6.2.1 and 6.2.2 summarise our findings, based on the scenarios outlined above. These results clearly illustrate the benefits of diversified charging behaviour in the long-term. Although deferred charging, Scenario 2, shows some merit at low EV penetration levels, its benefits are rapidly negated by the loss of diversity as the EV population grows.

Figure 6.2.1 Projected residential distribution transformer constraints

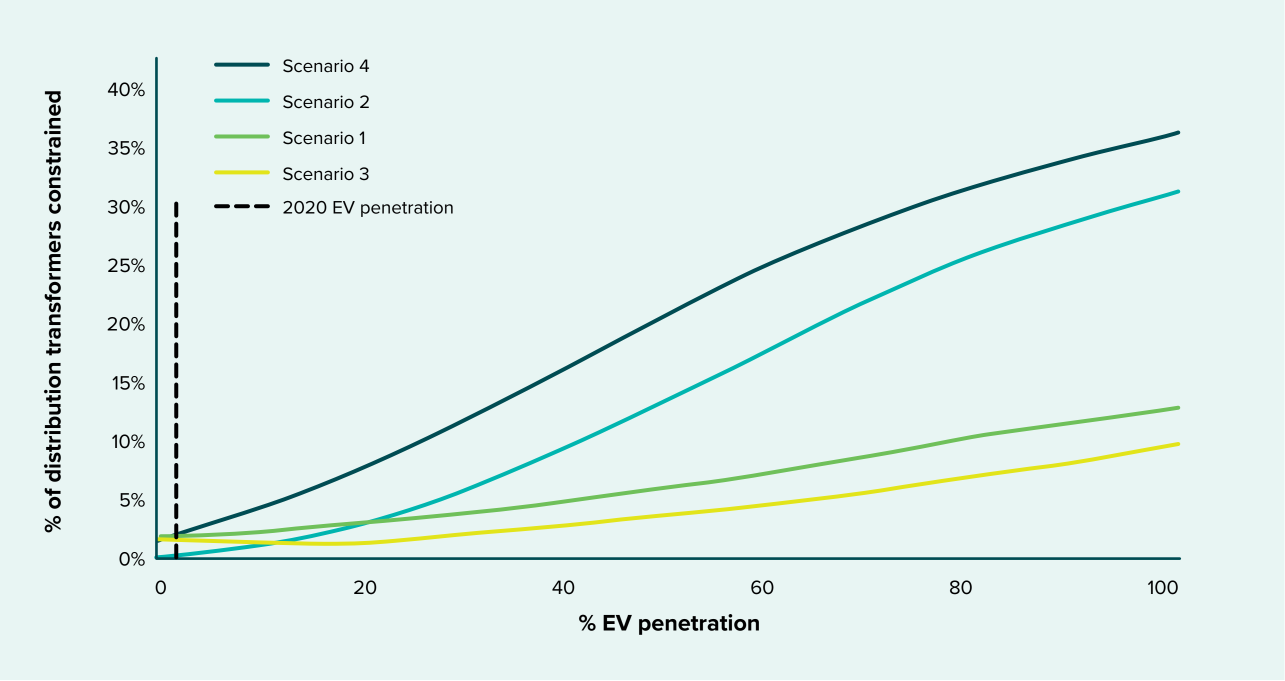
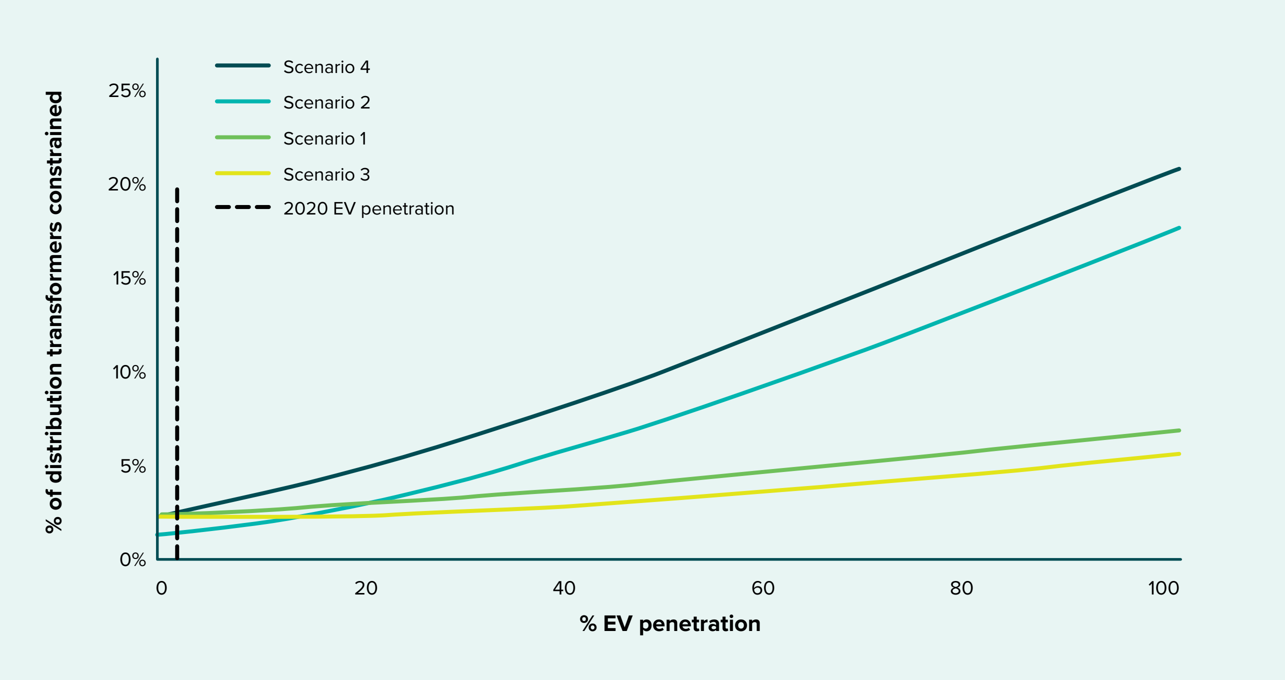


Figure 6.2.2 Projected residential LV network constraints



EV uptake in our region is currently estimated at around 2% of our total light vehicle population. However, due to the clustering effect, it is unlikely that these will be evenly distributed across the network. Therefore, while these results are useful for determining the high-level impact of electric vehicles on our LV network, it is important to validate them with real world measurements to inform our investment decisions. This is one of the reasons why we are seeking to monitor our low voltage network. See Section 6.2.1.1.

A further in-depth study is underway by EPECentre at the University of Canterbury on the worst LV networks identified by these results to analyse the variability in their performance based on EV battery capacities and charging behaviour.

6.2.2 Improving our systems

As our network evolves, we must ensure that our processes and systems keep pace and adapt to our new requirements. In the future, we aim to develop our forecasting and modelling capability in addition to improving the overall integration of our operational systems.

6.2.2.1 Enhanced data analytics

Improving our data analytics capability will enable us to forecast and model a range of performance factors, including transformer utilisation, voltage imbalance and power factor. The integration of this information with our other systems, such as our GIS platform will enable us to build a real-time digital model of our network.

Depending on the application, different forecasting and modelling techniques will be required to:

- allow the smart control of power electronics and energy storage, and in particular, the management of peak demand. By forecasting load just ahead of time, we could avoid outages as well as prolong the life of assets, translating into reduced customer interruptions
- assess investment choices for a subsequent financial year
- assess the potential impacts from scaled up adoption of low carbon technologies by customers, including clustering impacts

Improving our data analytics capability will enable us to forecast and model a range of performance factors, including transformer utilisation, voltage imbalance and power factor.

An enhanced digital network model will also enable improved:

- detection of electrical safety concerns both on our network and in customer premises which may be identified from smart meter information and our LV monitors
- power flow outputs which can allow us to identify voltage fluctuations, violation limits, fault currents etc., as a tool in the operation of our network

6.2.2.2 Integration with operational systems and business processes

We plan for our advanced distribution management system to be incrementally upgraded to support the anticipated future requirements, thereby avoiding the need to purchase and implement an entirely new management system, see Section 7.16. Our view is improvements will build on our existing load management and upper South Island coordination expertise.

It is also our desire to develop our systems to allow non-discriminatory secure data access and transfer to eligible market parties and customers. To help ensure this occurs in an efficient manner for our customers we will continue collaboration with retailers and other industry players on technology development, process and communications platforms.

Current examples of this are:

- installing low voltage monitoring systems on our LV feeders
- discussions with smart meter providers around data access

6.3 Preparing for growth

Network development is driven by growth in peak demand, not energy. The peak demand capability of our network is defined by network component capacities. For this reason, we concentrate on forecasting peak demand across all levels of our network, rather than energy usage.

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.

The factors and methodologies we use to estimate the quantity and location of load growth is described in our document: Long-term load forecasting methodology for subtransmission and zone substations. In summary, our method is to forecast growth at the zone substation level and translate this up to Transpower GXPs and finally to a total network demand forecast.

Our forecasts have a range of scenarios from uptake of electric vehicles, battery storage, solar photovoltaics and customer actions.

Our GXP and zone substation forecasts take account of our electric vehicle forecast, continued improvements in energy efficiency and growth in households and business associated with population growth. We have insufficient information to include any meaningful battery storage forecasts at this level but have included a possible scenario in the overall network total.

6.3.1 How we forecast demand growth

Our 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 has historically matched growth in population, including the holiday population for Banks Peninsula. Electricity consumption growth on the Canterbury Plains has been driven by changes in land use rather than population growth.

Our GXP and zone substation forecasts take account of our electric vehicle forecast, continued improvements in energy efficiency and growth in households and business associated with population growth.

6.3 Preparing for growth

This pattern reflects that, besides weather, two factors influence load growth:

- population increases
- changes in population behaviour

At a national level, it is reasonably easy to forecast population growth. When the national forecast is broken down to a regional level, the accuracy is less reliable but still useful in predicting future demand growth. 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 using Statistics NZ 2016 projections and historical trends in growth.

6.3.1.1 Our network maximum demand

Maximum demand is the major driver of investment in our network so it's important for us to forecast it as accurately as we can. This measure is very volatile and normally varies by up to 10% depending on winter weather. Our network maximum half hour demand, based on load through the Transpower GXPs, for FY20 was 604MW during the peak that occurred on 6 June 2019, up 24MW from the previous year.

In the medium-term maximum network demand is influenced by factors such as underlying population trends, new customers joining the network, growth in the commercial/industrial sector, changes in rural land use, climate changes and changes in customer behaviour.

Maximum demand is the major driver of investment in our network so it's important for us to forecast it as accurately as we can.

Many things influence changes in customer energy behaviour. It's these factors that are hard to predict in an era of rapid technology change. Some of the issues we need to consider are:

- **Electric vehicles** – EV uptake rates are uncertain, what proportion of EV drivers will charge at home and when, the diversity of home charging and what size charger will be used are all current unknowns.
- **Customer actions** – how customers will respond to signals of high cost power or high CO2 generation are unknown. A focus on decarbonisation could lead to improved house insulation, greater appliance efficiency, and customers responding to reduce peak load. We could also see a shift from polluting generation in industrial boilers, to renewable electricity usage.
- **Solar photovoltaics** – the future uptake rate, and size of solar installations is uncertain.
- **Batteries** – battery uptake rates remain uncertain, as does knowledge of how our customers will use batteries. Customers may discharge batteries at expensive evening peak times, and recharge the batteries at cheaper times, or may discharge their batteries when they get up in the morning and through the day – meaning evening electricity usage may still be from the grid.

Given the range of impacts new technology brings, we can no longer rely on maximum demand forecasts based primarily on historical growth. Instead we've moved to scenario based maximum demand forecasting as shown in Figure 6.3.1.

All our maximum demand scenario planning assumes solar photovoltaics have no effect on the peak, which occurs on a winter evening after sunset – i.e. at a time when the sun isn't shining.

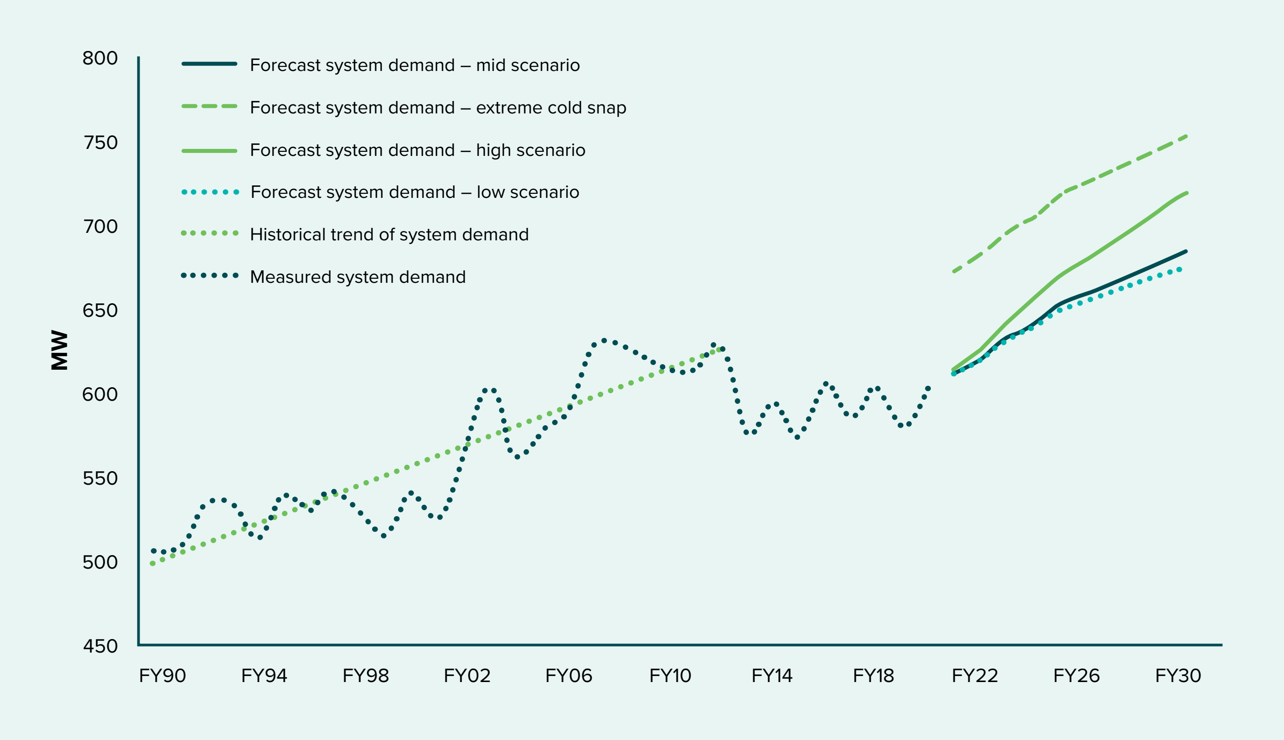
Our total network forecast is higher than the linear history due to the forecast population increase in our region, industrial development in Rolleston, and ongoing regeneration in the central city. Winter peak demand on our network is anticipated to increase by approximately 80MW (14%) over the next 10 years. This is based on the mid scenario shown in Figure 6.3.1. Significant volatility can be expected in annual actual maximum demands, with 10% variation depending on winter weather. Capital investment plans will be modified as load growth is observed.

Our maximum demand is linked with cold weather. The extra growth in forecast maximum demand for the next few years is due to the Convention Centre, the Canterbury Multi-Use Arena and Lincoln University moving from coal to electricity for heating.

Given the range of impacts new technology brings, we can no longer rely on maximum demand forecasts based primarily on historical growth.

6.3 Preparing for growth continued

Figure 6.3.1 Overall maximum demand trends on the Orion network



Descriptions of the four Figure 6.3.1 forecast scenarios are:

- **Low scenario** – the low scenario is based on continued energy efficiency at 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 to meet the charging needs of electric vehicles.
- **Mid scenario** – 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 ~10% of the region's vehicle fleet will be electric in 10 years and we have assumed 20% charging at peak times. Energy efficiency continues 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, and the Ōtākaro Central City Recovery plan also implies fewer, much smaller builds.

  This forecast does not include the effects of batteries which have more uncertain uptake and impact at peak winter times. We do not believe the uptake of batteries will be significant in the next 10 years due to the economics of batteries, and any impact batteries have in reducing peak load is likely to be offset by industrial decarbonisation efforts increasing usage of electricity at peak times.
- **High scenario** – this high scenario shows the consequences of further energy efficiency gains becoming unattainable or being offset by the replacement of coal boilers by electric boilers, and a doubling of the electric vehicle impact – either double the number of EVs or double the number charging at peak.
- **Potential extreme cold snap peak** – this forecast is based on events similar to 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.

With the changing energy landscape, maximum demand will also need to be closely monitored at the low voltage level to ensure the capacity of the LV network is sufficient. This is because clustering of new technologies may occur at a street or neighbourhood level, before overall numbers on our network are substantial.

6.3.1.2 Demand forecasting uncertainties

This section provides further detail on some of our assumptions with regard to the more significant uncertainties we face in our demand forecasting.

COVID-19

The impact of the worldwide COVID-19 pandemic and associated responses could change load. Data suitable for updating our forecasts is not available at the time of writing. The changes could be due to:

- significant population growth as New Zealanders return home and immigrants seek safety here
- businesses closing from restricted movements (both local lockdowns and curtailed international tourism)
- a jump in unemployment leading to more people at home using heating and cooling

Current information indicates there aren't any Major Projects in the next couple of years that are expected to change due to these factors.

Energy transformation and climate change

In the future, it is anticipated electricity networks will undergo major changes in consumer energy usage habits due to increased customer choice and the impact of climate change. At a national level, Transpower has produced their Te Mauri Hiko – Energy Futures long-term vision of future electricity use. The focus of this vision is the 20-50 year range as opposed to our 5-10 year planning horizon. Being at a national level it is difficult to translate this into the projected impact on our network. We will however use their underlying information where it provides a forecast that better matches observed changes compared with other projections.

> **In the future, it is anticipated electricity networks will undergo major changes in consumer energy usage habits due to increased customer choice and the impact of climate change.**

Milk processing plants

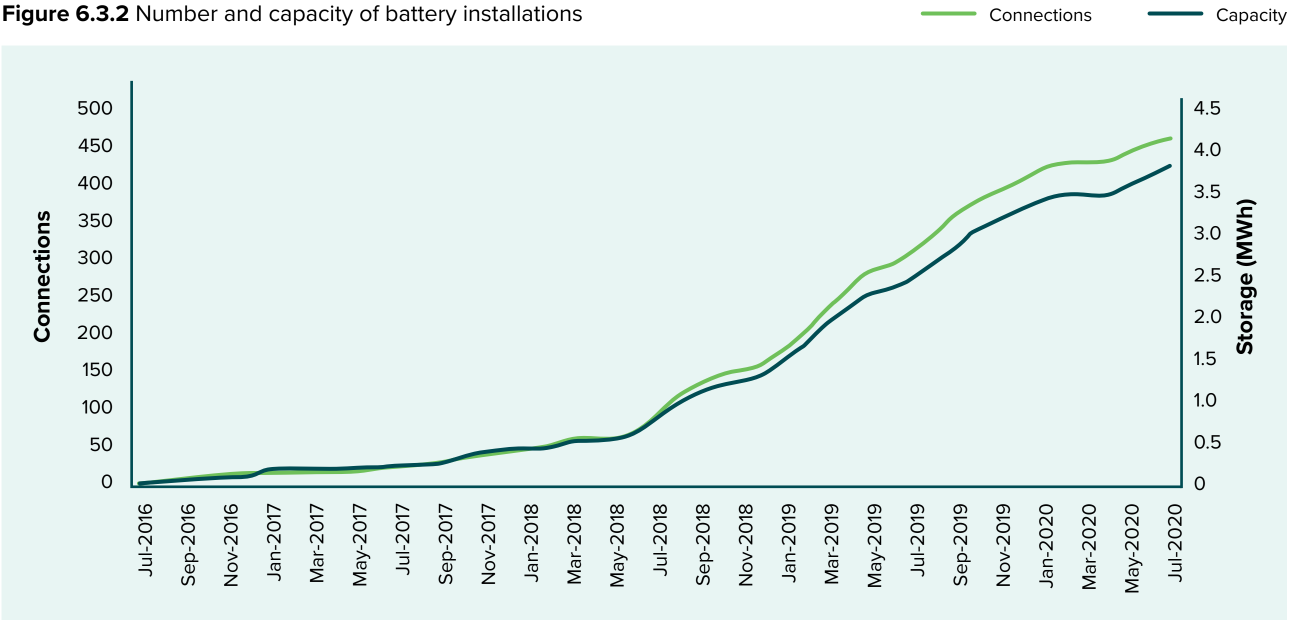
The timing and demand changes due to possible moves by milk processing plant operators causes significant forecasting uncertainty. For this reason, we are cautious about our development plans to ensure that we do not install assets that may later become underutilised.

Battery storage

Customer battery storage connected to our network has been increasing approximately 1MWh/year since January 2019 with the average capacity per installation being 8kWh. Although this is presently not significant, the charging and discharging orchestration of battery storage will influence the observed system peak as the battery capacity grows.

Figure 6.3.2 shows the number and capacity of battery installations on our network.

Figure 6.3.2 Number and capacity of battery installations

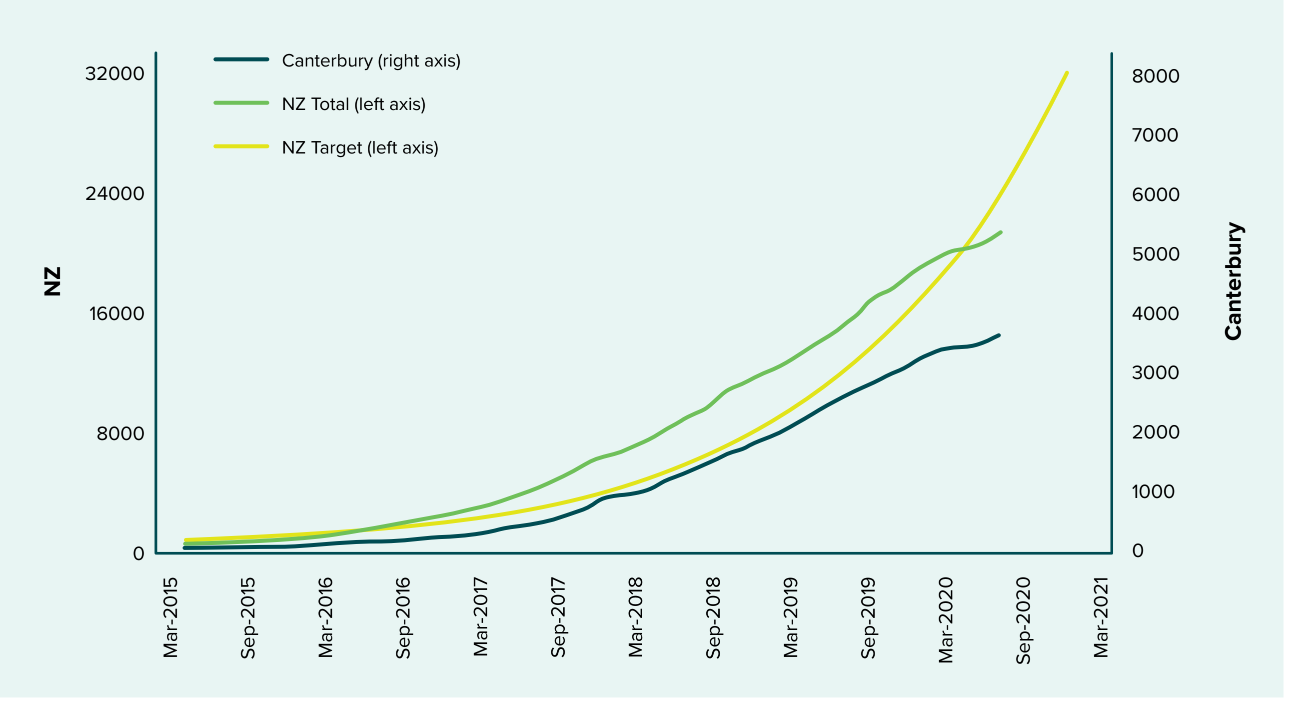


6.3 Preparing for growth continued

Electric vehicles

Electric vehicle uptake was increasing above forecasts until the COVID-19 pandemic lockdown flattened the curve. Until then the prime driver had been used Nissan LEAF imports which make up two-thirds of the local EV fleet. Clustering of EV uptake due to neighbourhood demographics may impact areas of the low voltage network before overall numbers are substantial. Data from vehicle registrations indicates the suburbs with a higher concentration are Cashmere and Halswell. There is potential for this to develop rapidly as shown in the Figure 6.3.3.

Figure 6.3.3 Electric vehicle uptake in Canterbury



We have conducted some preliminary research into the impacts of EV uptake on our LV network. Results of this research are summarised in Section 6.2.1.4.

Distributed generation

In conjunction with University of Canterbury, and thanks to MBIE research funding, we have contributed to the development of a Distributed Generation Connection Guideline. The guideline requires distributors to establish a Distributed Generation (DG) hosting capacity for each low voltage network feeder. This hosting capacity will be based on an expected medium-term uptake/penetration level.

Figure 6.3.4 shows solar uptake in terms of connections and capacity since 2008. Solar PV penetration is about 1% by network connection count and less than 1% of energy delivered. The installed capacity has reached 1.5%. Figure 6.3.5 shows that the uptake rate peaked late 2016 and is now dropping.

Figure 6.3.4 Current level of solar PV uptake on our network

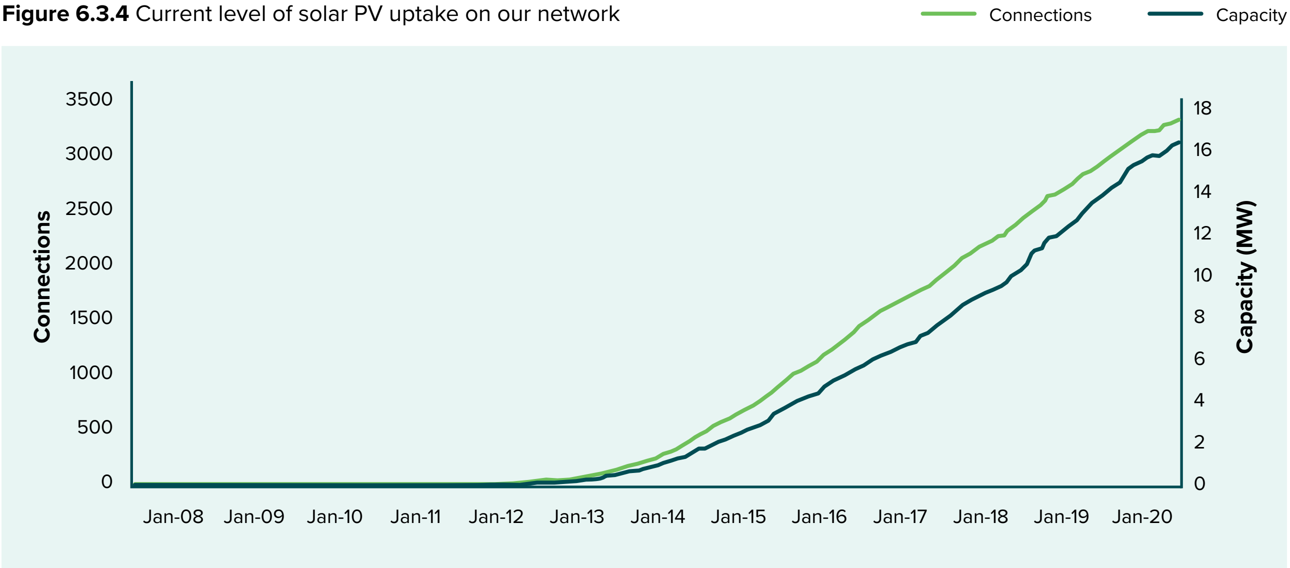
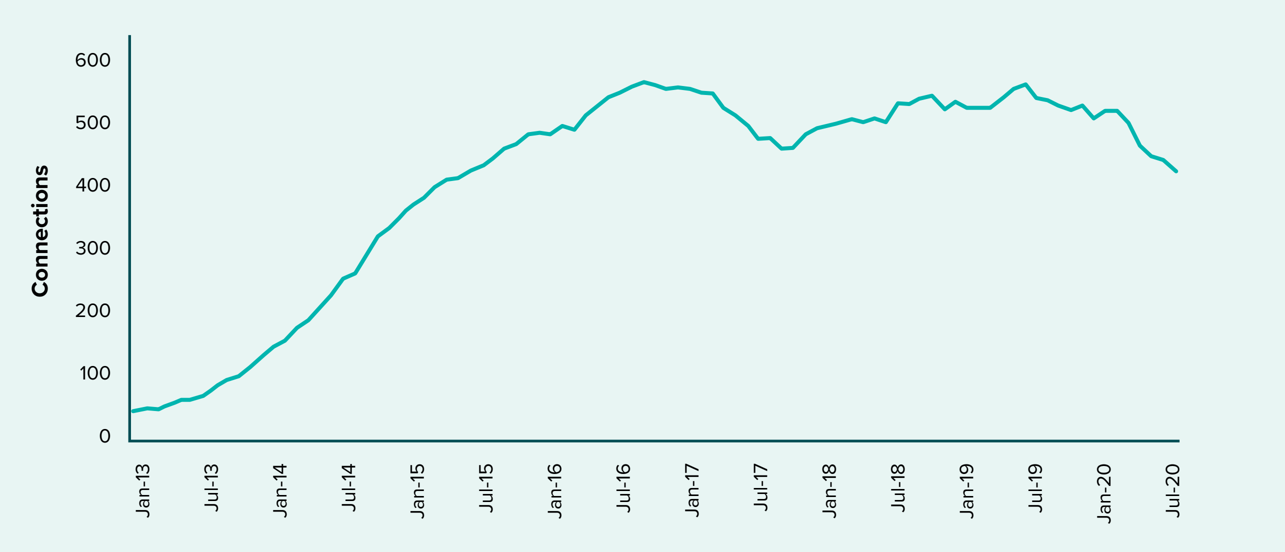


Figure 6.3.5 Rolling 12 month increase in solar PV connections



Subdivisions

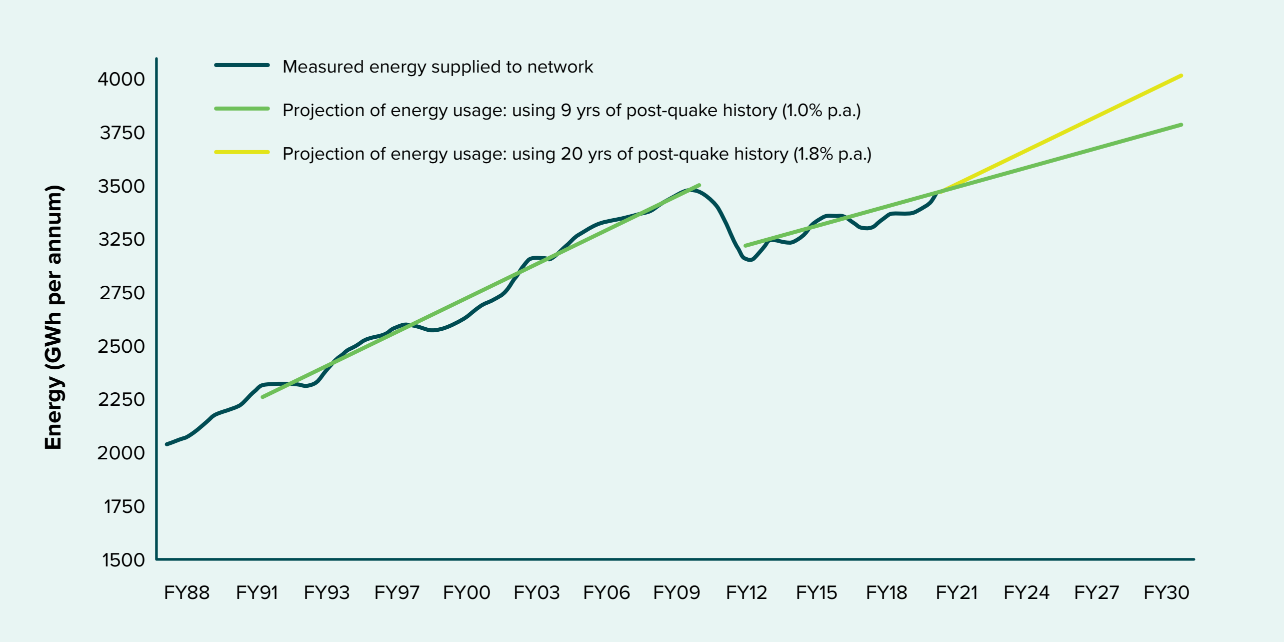
The level of subdivision activity depends on economic conditions and population growth. The response to COVID-19 may include an increase in immigration to NZ but data to inform forecasting is not yet available. The most recent population forecast update has the annual increase in households remaining approximately 3,000 for several years then dropping to 2,000.

In our rural area most subdivisions are for residential living. In our urban area it can be industrial, commercial or residential, though most developments are residential.

6.3.2 Our network's energy throughput

Prior to the 2010/11 Canterbury earthquakes, our network showed an average energy growth rate of about 1.8% per year, see Figure 6.3.6. The drivers behind this were population growth in Christchurch, growth in holiday population for Banks Peninsula and changes in land use on the Canterbury Plains. For the years post the Canterbury earthquakes, this rate decreased to approximately 1.0% per year, due to more energy efficient new housing and commercial buildings and more energy efficient domestic heating and production processes.

Figure 6.3.6 System energy throughput



6.3.3 Territorial authority growth

Our network spans two territorial authority areas: Christchurch City Council (CCC) and Selwyn District Council (SDC). The following information summarises our forecasts for each of these territorial areas, before we move into demand forecasts at GXP and zone substation level. Both territorial authorities publish useful area planning information and we use this extensively to plan for growth on our distribution network. Their plans are informed by the Greater Christchurch Partnership which is a collaboration between local councils, iwi and government organisations.

6.3.3.1 Christchurch city demand growth forecast – Region A

To forecast the growth in residential demand in the Christchurch city area, we map each of the census area units to one or more zone substations in our model.

To forecast industrial growth, we utilise Christchurch city industrial vacant land reports to identify areas developed and zoned for potential growth. We utilise historic uptake rates and market judgement to allocate 20Ha of growth per annum to the different areas of available land. These allocations are mapped in our model to a zone substation with a forecast load density of 130kW per hectare.

Finally, we use CCC land zone maps to determine the areas suitable for commercial/industrial infill growth. This part of our forecast is a relatively discretionary process and is heavily dependent on the vagaries of the commercial development market.

Overall Region A growth is winter dominated and follows the same trend as the maximum demand of the overall network. See Figure 6.3.1.

In the medium-term, CCC's District Plan review expects to deliver an increase in residential infill within the Christchurch central city and areas around shopping malls by introducing Medium Density Residential zones and Suburban Density Transition. In the short-term, major subdivision growth is planned for Halswell and the central city East Frame. Industrial development is expected to mainly continue in Islington, Belfast and airport areas.

6.3.3.2 Central Canterbury and Banks Peninsula demand growth forecast – Region B

For Region B, we use the latest SDC household growth projections to forecast residential growth in the greater Selwyn region. Most of our zone substations within Selwyn District are required to meet irrigation load and predominately have their peak load in summer. However significant residential growth has occurred around Rolleston, Larcomb and Lincoln zone substations and these substations have their peak load in winter. Region B, the majority of which is in Selwyn District, network peak is anticipated to increase by approximately 20MW (15%) in the next 10 years.

The increased focus on decarbonisation of industry also contributes to the electrical growth in this region.

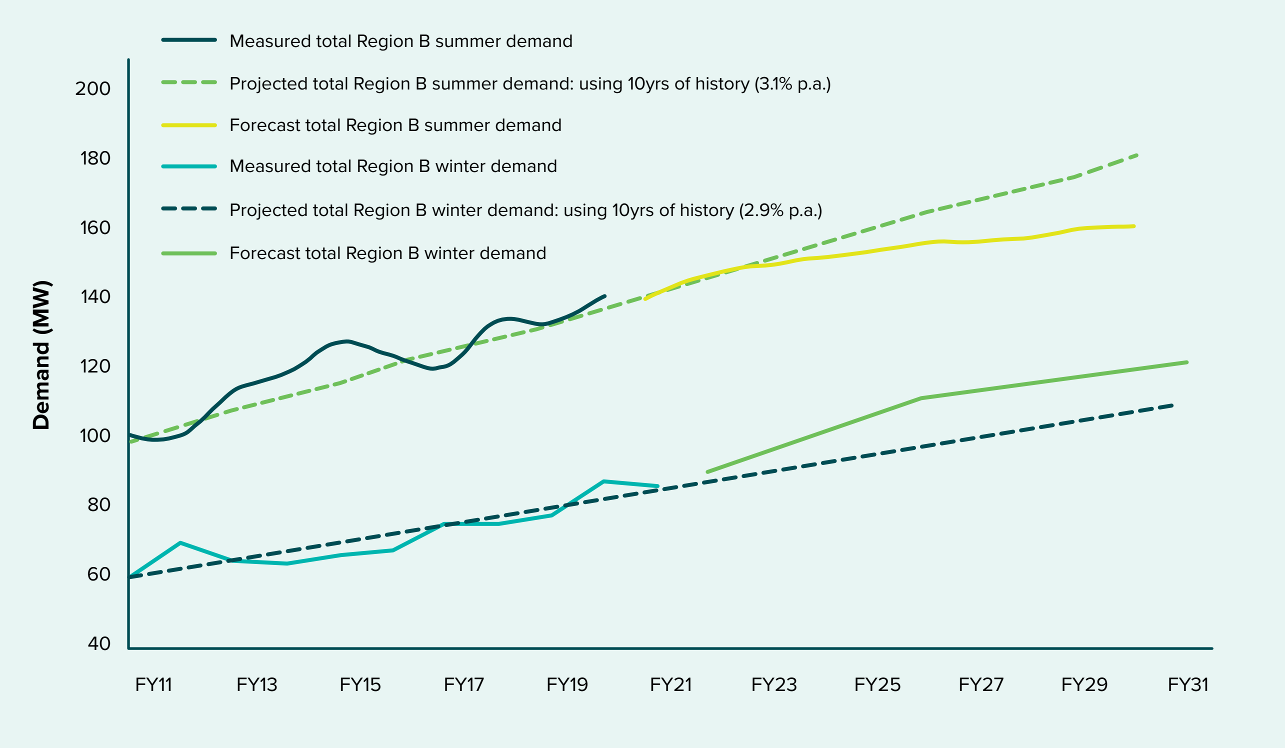
Figure 6.3.7 shows recent summer load growth in our Region B area. FY13, FY15 and FY18 were good examples of a dry summer. FY14 irrigation demand was subdued due to rain events during the summer months. This was offset by Fonterra adding a second drier to their plant near Darfield.

Region B winter load growth is also shown in Figure 6.3.7 with the FY12 peak due to a significant August snowstorm.

The SDC residential forecast indicates significant growth is expected to continue around Rolleston and Lincoln townships for a few years. Higher than normal growth is also expected due to planned development at Lincoln University.

The increased focus on decarbonisation of industry also contributes to the electrical growth in this region.

Figure 6.3.7 Region B maximum demand



6.3 Preparing for growth continued

6.3.4 Present loading

Region A geographical map in Figure 6.3.8 demonstrates areas of high and moderate loading on our network.

The changes from our 2019 AMP are:

- Harewood decommissioned
- Sockburn moved to less than 90%
- Rawhiti moved to less than 70%

Figure 6.3.8 Zone substations – Region A (FY20 maximum demand as a percentage of firm capacity)

Key:

◉ Transpower GXP

Maximum demand - as a percentage of firm capacity

🔴 More than 90%

🟠 Between 70% and 90%

🟢 Less than 70%

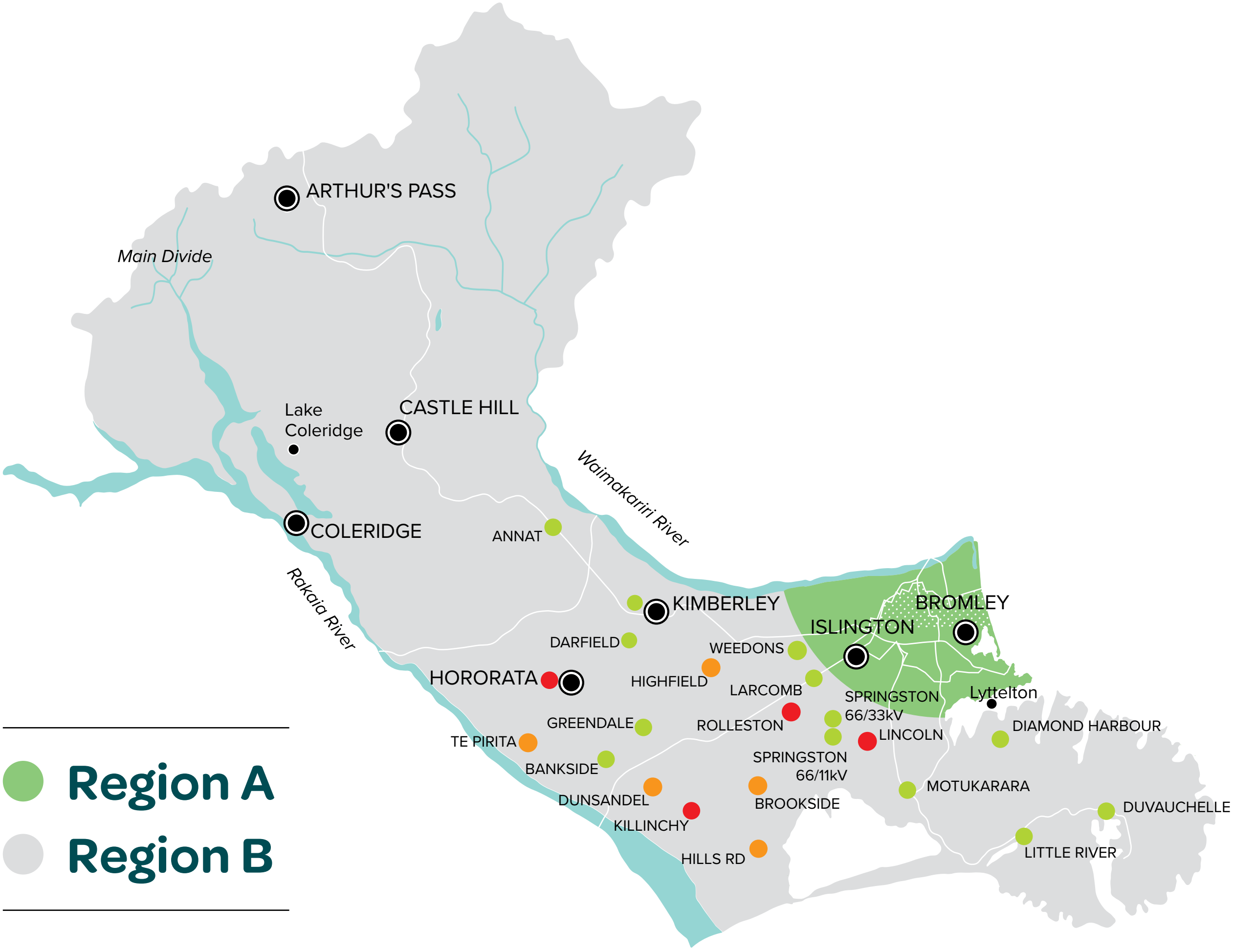
6.3 Preparing for growth continued

The Region B geographical map in Figure 6.3.9 demonstrates areas of high and moderate loading on our network. Substations with load exceeding 90% of firm capacity have been coloured red.

The changes from our 2019 AMP are:

- Hororata and Killinchy moved to more than 90%
- Brookside, Dunsandel, Highfield, Hills and Te Pirita moved to less than 90%
- Darfield, Greendale and Springston 66/33 moved to less than 70%.

Figure 6.3.9 Zone substations – Region B (FY20 maximum demand as a percentage of firm capacity)



Key:

◉ Transpower GXP

Maximum demand - as a percentage of firm capacity

🔴 More than 90%

🟠 Between 70% and 90%

🟢 Less than 70%

6.3.5 Load forecast

Using the inputs detailed in the previous sections, we have forecast our GXP and zone substation load for the next 10 years. Each substation is assigned a Security Standard Class which outlines our restoration targets under different contingency scenarios (refer to Section 6.4.1 for further details). Firm capacity is determined by calculating the remaining capacity of each site should one item of plant fail (N-1).

6.3.5.1 Transpower GXP load forecasts

Table 6.3.1 indicates the capacity of each Transpower GXP that supplies our network. Present and expected maximum demands over the next 10 years are also shown.

Note the impact of projects incorporated in this plan is not reflected in the GXP load forecasts. The tabled loads are those expected if no development work is undertaken. 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.

Table 6.3.1 GXP substations – load forecasts (MVA)

GXP substation	Security Standard Class	Firm capacity	Actual FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Bromley 66kV	A1	220	129	130	131	132	133	134	134	135	136	137	138	139
Islington 33kV	B1	107	70	70	71	76	77	79	80	82	83	84	86	87
Orion Islington 66kV	A1	494 [1]	392	410	417	427	434	443	447	451	455	459	463	469
Hororata 33kV [2]	C1	23	23	21	21	21	21	21	21	21	21	21	21	22
Kimberley 66kV, Hororata (66 & 33kV)	C1	70 [3]	49	45	46	46	46	46	47	47	47	47	48	48
Arthur's Pass	D1	3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Castle Hill	D1	3.75	0.6	0.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Coleridge	D1	2.5	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Notes:

1. **532 MVA total firm capacity.** Assumes only 32% of Mainpower's load is fed from Islington post Islington T6 contingency. Constraint to be resolved by transferring McFaddens from Islington to Bromley
2. **Monitor growth and transfer load to Hororata 66kV if needed in the short-term.** Project 604 scheduled for FY26/27 to reduce loading on this GXP by transferring Bankside from the 33kV to the 66kV subtransmission network.
3. **Assumes full generating capacity available from Coleridge.** Can be limited to 40MW capacity when Coleridge is not generating or providing reactive support

6.3.5.2 Zone substation load forecasts

The following two tables compare the firm capacity of each of our zone substations with present and forecast load. The electric vehicle uptake scenario and customer actions described in Section 6.3.1.1 have been incorporated into the forecasts. The uptake of solar PV connections is being recorded but not incorporated into the forecasts because the impact on peak demand, especially winter peaking areas, is negligible/zero. At this stage we have not incorporated the impact of battery storage into our zone substation forecasts as we do not anticipate the impact of batteries to be significant within the next ten years.

The "Year 10 High EV Impact" in the final column of Table 6.3.2 shows the potentially higher load if there is:

- clustering of EV uptake three times higher than the network average. This scenario allows for accelerated localised uptake due to neighbourhood influence i.e. neighbours are more likely to buy an EV, if EVs are more common in the area, and
- diminished response to measures to encourage charging away from peak. This allows for twice as many charging at 6pm i.e. 40% of EVs

Table 6.3.2 Region A 66 and 33kV zone substations – load forecasts (MVA)

Zone substation	Security Standard class	Firm capacity	Actual winter FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Year 10 High EV Impact
Addington 11kV #1	B2	30	16	16	16	19	19	19	19	19	19	19	19	19	20
Addington 11kV #2	B2	30	19	19	19	19	19	19	19	19	19	19	20	20	20
Armagh	A2	40	17	18	18	19	20	21	22	22	23	23	24	25	27
Barnett Park	B3	15*	8	8	8	8	8	8	8	8	9	9	9	9	10
Bromley	B2	60	30	30	30	31	31	31	31	32	32	32	32	33	36
Dallington	B2	40	27	28	28	28	28	28	28	28	28	28	29	29	32
Fendalton	B2	40	35	35	35	34	34	34	34	35	35	35	35	35	37
Halswell	B2	23	20	18	19	20	21	22	22	23	23	24	24	25	28
Hawthornden	B2	40	31	33	32	32	32	32	33	33	33	33	33	33	35
Heathcote	B2	40	22	23	23	23	23	23	23	23	24	24	24	24	24
Hoon Hay	B2	40	32	29	29	29	30	30	30	30	30	31	31	32	35
Hornby	B2	20	16	16	16	17	17	17	17	18	18	18	18	18	18
Ilam	B3	11	7	7	8	8	8	8	8	8	8	8	8	8	8
Lancaster	A2	40	19	19	19	20	20	20	20	20	20	21	21	21	21
McFaddens	B2	40	34	34	34	34	34	35	35	35	35	35	35	35	39
Middleton	B2	40	26	26	27	27	27	28	28	28	28	28	28	28	28
Milton	B2	40	35	38	38	38	38	39	39	39	39	40	40	40	40
Moffett	B3	23	14	14	15	15	16	16	17	17	18	19	19	20	20
Oxford Tuam	A2	40	12	15	15	15	15	16	16	16	16	16	16	16	16
Papanui	B2	48	36	39	40	40	41	41	42	43	43	44	44	45	46
Prebbleton	B3	15	7	7	7	7	7	7	7	8	8	8	8	8	9
Rawhiti	B2	40	27	27	27	27	27	27	27	27	27	27	27	28	31
Shands	B3	20	13	14	17	17	17	18	18	17	17	17	18	18	18
Sockburn	B2	39	22	22	23	23	23	23	23	24	24	24	24	25	25
Waimakariri	B2	40	23	22	22	23	23	23	23	24	24	24	24	24	24

* 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

Proposed resolution is as follows:

Halswell	Load transfer to Hoon Hay then a transformer upgrade
Milton	Load transfer to Addington zone substation
Papanui	Transfers to Waimakariri & new Belfast zone substation

6.3 Preparing for growth continued

Table 6.3.3 Region B 66 and 33kV zone substations – load forecasts (MVA)

Zone substation	Security Standard class	Firm capacity	Actual FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Year 10 High EV Impact
Annat*	C4	7.5	3.9	4	4	4	4	4	4	4	4	4	4	4	4
Bankside*	C3	10	5.7	5	5	5	5	5	5	5	5	5	5	5	5
Brookside 66kV*	C3	10	8.7	9	9	9	9	9	9	9	9	9	9	9	9
Darfield*	B3	8.8	5.6	6	6	6	6	6	6	6	6	6	6	6	6
Diamond Harbour*	B3	7.5	2.5	3	3	3	3	3	3	3	3	3	3	3	3
Dunsandel	A2	23	17.1	17	17	17	17	17	17	17	17	17	17	17	17
Duvauchelle	B3	7.5	4.3	4	4	4	4	4	4	4	4	4	4	4	4
Greendale*	C3	10	6.5	6	6	6	6	6	6	6	6	6	6	6	6
Highfield*	C3	10	8.5	9	10	10	10	11	11	11	11	11	11	11	11
Hills Rd*	B3	10	7.2	7	7	8	8	8	8	8	8	8	8	8	8
Hororata*	C3	10	9.2	9	9	9	9	9	9	9	9	9	9	9	9
Killinchy*	C3	10	9.2	9	9	9	9	9	9	9	9	9	9	9	9
Kimberley	A3	23	14.5	15	15	15	15	15	14	14	14	14	14	14	14
Larcomb	B3	23	14.1	14	15	17	17	18	18	18	19	19	20	20	22
Lincoln	B3	10	10.5	10.2	11	11	12	12	12	12	13	13	13	13	15
Little River*	C4	2.5	0.7	1	1	1	1	1	1	1	1	1	1	1	1
Motukarara	C4	7.5	3.5	4	4	4	4	4	4	4	4	4	4	4	4
Rolleston	B3	10	11.7	10	10	11	11	11	11	11	11	11	11	12	13
Springston 66/33kV	B2	60	37.6	37	40	42	45	49	50	51	51	51	51	50	52
Springston 66/11kV*	B3	10	6.9	7	8	10	11	14	15	15	15	15	15	15	15
Te Pirita	C3	10	7.5	9	9	9	9	9	9	9	9	9	9	9	9
Weedons	B3	23	12.1	13	14	14	15	15	15	15	16	16	16	17	17

* Denotes single transformer or line substation

🟩 Indicates load greater than firm capacity

Proposed resolution as follows:

Highfield	Rerate transformer when customer upgrade confirmed. Transfer load to Norwood when Burnham is built
Lincoln & Springston	Load shift to Springston where a second transformer added when needed
Rolleston	Load shift to Larcomb, Weedons and Highfield, then construct new Burnham 23MVA substation to replace Rolleston

6.4 Planning criteria

When planning our network, we:

- take account of customer feedback to determine the value they put on reducing interruption times. This gives an upper threshold of how much reliability investment is justified
- preserve our HV security of supply standard, which is the ability of our network to meet the demand for electricity when electrical equipment fails
- monitor our network utilisation thresholds to prepare an annual reinforcement programme for our network
- compare our current network capacity with load forecast scenarios. The resulting projects are based on our design standards
- projects are based on our design standards. The projects are then prioritised taking account of the ability to deliver the work each year
- consider, especially as the network becomes constrained, non-network solutions to relieve these constraints as an alternative to or to delay network investment

We take account of customer feedback to determine the value they put on reducing interruption times. This gives an upper threshold of how much reliability investment is justified.

6.4.1 HV security of supply standard

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances when electrical equipment fails. 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.

Security of supply underpins our HV network resilience.

Security of supply underpins our HV network resilience. It is grounded in the flexibility of our network to be reconfigured to provide power from alternative sources when needed. Security of supply differs from reliability, which is how the network performs, measured by the frequency and duration of power outages per customer.

In addition to our security of supply standard, customers are given the opportunity at the time of initial connection to discuss their individual security of supply requirements. We will also make changes to individual security of supply arrangements for existing customers.

Our security of supply standard caters for connections of sizes that meet our major customer's needs and individual security arrangements on our network are minimal. They are mainly limited to high profile services such as hospitals, ports, Christchurch International Airport and public sports venues. We also have in place individual security of supply agreements with milk processing plants at Darfield and Dunsandel.

6.4 Planning criteria continued

Table 6.4.1 Network supply HV Security 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

Note 1. Assumes the use of interruptible irrigation load for periods up to 48 hours.
Note 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.

6.4.2 Network utilisation thresholds

Historic loading data from our DMS and forecast zone substation and subtransmission utilisation figures are used to prepare our 10-year programme of works for our network.

Growth at the 11kV distribution level is largely dependent on individual subdivision development and customer connection upgrades. Growth in excess of the system average is not uncommon and localised growth rates are applied as necessary. Zone substations, subtransmission and distribution feeder cables are subject to four distinct types of peak load:

1) **Nominal load –** the maximum load seen on a given asset when all of the surrounding network is available for service.
2) **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.
3) **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.
4) **Bus fault 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 security of supply standard, the location and quantity of load supplied by a feeder has a bearing on whether all or only some of the four load categories described above should be applied to an asset for analysis.

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

6.4.3 Capacity determination for new projects

When a capacity or security gap is identified on the network we consider different capacity 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.

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

The capacity of a new zone substation and 11kV feeders is generally dictated by the desire to standardise network equipment. The capacity of a zone substation and transformer/s is based mainly on the load density of the area to be supplied and the level of the available subtransmission voltage. 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 new cables. When overhead line capacities are exceeded, an upgrade of the current carrying 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. We discuss our approach to increased capacity in our architecture and network design document.

Table 6.4.2 provides a summary of our standard network capacities.

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

6.4 Planning criteria continued

Table 6.4.2 Standard network capacities

Location	Subtransmission voltage	Subtransmission capacity		Zone substation capacity	11kV feeder size (Notes 1 & 2)	11kV tie or spur (Note 1)	11/400kV 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.

6.4.4 Project prioritisation

Prioritisation of network solution projects for capacity and constraints is a complex process that involves multiple factors that are both external and internal to Orion.

The primary factors to be considered when prioritising projects, in decreasing order of significance, are:

1) **Coordination with NZ Transport Authority and local authority civil projects** – where projects are known to occur in the same location, we aim to schedule our projects to coincide with the timing of key civil infrastructure projects by these two parties. 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 cables or excavate and then reinstate newly laid road seal.
2) **Satisfying individual or collective customer expectations** – we work hard to satisfy the needs of our customers. We give priority to addressing constraints most likely to impact customer supply through extended or frequent outages, or compromised power quality.
3) **Managing service provider resource constraints** – we aim to maintain a steady workflow 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.
4) **Coordination with Transpower** – we endeavour to coordinate any major network structural changes adjacent to a GXP with Transpower's planned asset replacement programmes, and provide direction to Transpower to ensure consistency with our sub-transmission upgrade plans.
5) **Our asset replacement programme** – we extensively review areas of the network where scheduled asset replacement programmes occur to ensure the most efficient and cost-effective solution is sought to fit in with the current and long-term network development structure, for example replacement of switchgear in substations.
6) **Our asset maintenance programme** – we seek to schedule any major substation works and upgrades to coincide with asset maintenance programmes, for example zone substation transformer refurbishment.

After assessing their relative priorities, the final decision to undertake investment in projects for the coming year depends on urgency. Other factors also apply, such as seasonal timing to avoid taking equipment out of service during peak loading periods. This means we endeavour to undertake projects in metropolitan areas in summer and projects in farming areas in winter. It is also important we consider the order of interconnected projects.

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.

The recent and forecast improvement in battery technology and forecast drop in price is likely to create new Distributed Energy Resources Management opportunities in the short to medium-term. We will continue to monitor and investigate opportunities.

For some major projects, we would consider paying for Distributed Energy Resources Management to avoid or defer network development. These projects, and an indication of the value possible are detailed in Section 6.7.

6.4.5 Non-network solutions

When the network becomes constrained it is not always necessary to relieve that constraint by investing in new zone substations, 11kV feeders and 400V reinforcement. Before implementing network investment solutions, we look for network switching options and then consider the following alternatives:

- Distributed Energy Resources Management
- Distributed Generation
- Uneconomic connections

6.4.5.1 Distributed Energy Resources Management

Distributed Energy Resources Management provides an alternative to transmission and distribution network development.

We are open to exploring projects with customers or third parties in the DER space and are keen to partner where there are mutual benefits.

This promotes efficient operation of the network.

Some of the gains from Distributed Energy Resources Management are:

- increased utilisation of the network
- improved utilisation of Transpower's transmission capacity
- customers benefit by becoming more efficient in the utilisation of energy and network capacity
- customer relations improve through less upward pressure on prices

The following Distributed Energy Resources Management strategies are applied by Orion:

- ripple system – anytime hot water cylinder control
- ripple system – night rate price options
- ripple system – major customer price signalling
- ripple system – interruptible irrigation
- coordinated upper South Island load management
- power factor correction rebate
- diesel-fueled generation

Ripple control

Ripple control is one of the most effective tools available for implementing Distributed Energy Resources Management. Committed utilisation of our ripple control system has been the driver for approximately 150MW of the 200MW gap between demand and energy.

Ripple control has facilitated the implementation of the following Distributed Energy Resource Management:

- hot water cylinder control – 50MW of peak load deferment
- night store heating – 190MW of night load providing an estimated 75MW peak reduction
- peak price signalling mainly major customers – 25MW, includes embedded generation
- interruptible irrigation load groups (summer only) – 15MW during contingencies

We will continue to work with retailers, customers and meter owners to ensure that the benefits of ripple control are retained during any transition to new technology options.

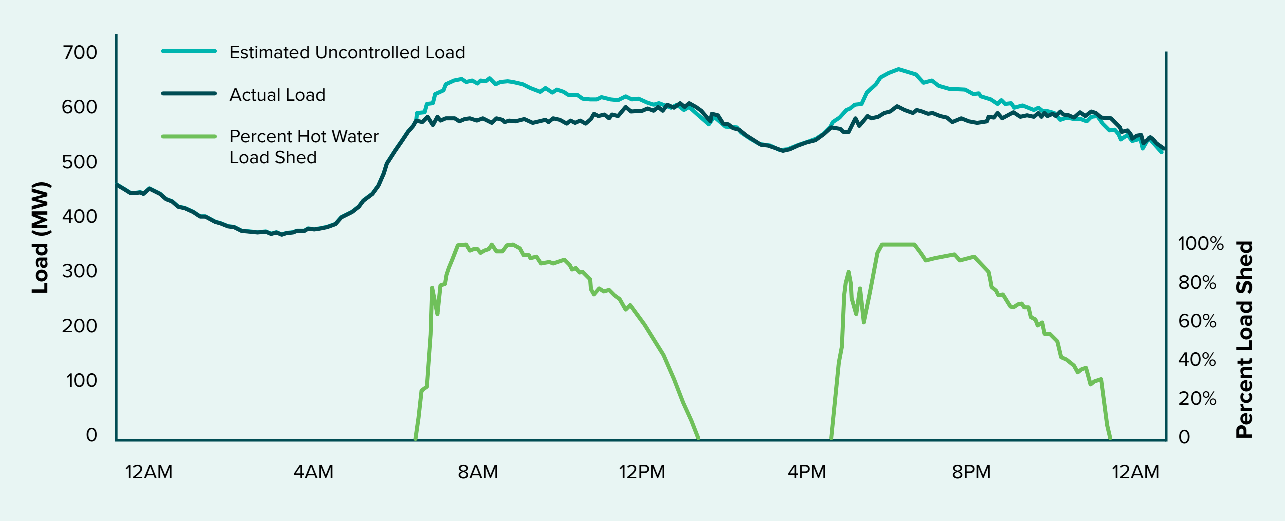
Winter load management

We design our network to meet peak demand, which we manage through hot water cylinder peak control and night rate price signalling. As network development costs and the transmission grid usage charges are driven by peak demand, the growth in the cost to our customers has been kept much lower than growth in overall annual demand.

A demonstration of the effectiveness of our winter load management, via hot water cylinder control and peak price signalling, in reducing the overall network load is shown in Figure 6.4.1 below.

> **Distributed Energy Resources Management is shaping the overall customer load profile to obtain maximum mutual benefit to the customer and the grid and network operator.**

Figure 6.4.1 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.

Coordinated upper South Island load management

As well as controlling hot water cylinder load to manage peaks on our own network 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.

Cooperation and the coordination of upper South Island load management enables us to reduce peaks without excessive control of hot-water cylinders.

Interruptible load groups – irrigation

Orion offers an Irrigation Interruptibility Scheme where we pay rebates to customers who allow us to interrupt the supply to designated irrigators during a capacity emergency to help keep the power on for the wider community.

Used only rarely, 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.

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 where the predominately underground network is high in capacitance which helps to improve power factor, 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.

6.4.5.2 Distributed Generation

The purpose of our distribution network has been to deliver bulk energy from Transpower GXPs to customers. In certain circumstances it can be more economic for the customer to provide a source of energy themselves in the form of Distributed Generation. Distributed Generation may also reduce the need to extend our network capacity.

We approach Distributed Generation in different ways, depending on the size of the system. For Distributed Generation above 750kW we consider the following issues:

- coincidence of Distributed Generation with Transpower interconnection charges
- benefits of avoided or delayed network investment
- security of supply provided by generators as opposed to network solutions
- hours of operation permitted by resource consents
- priority order for calling on peak lopping alternatives, such as hot-water control versus Distributed Generation

Region A load peaks on a winter evening when there is no solar PV generation. Diesel generation can reduce peak loads so is included in our peak forecast. Solar PV may offer a reduction to peak demand on our Region B network which is driven by summer irrigation load.

For diesel generation to be effective we require a contract to ensure peak lopping is reliably achieved. This is done through pricing structures that encourage users to control load at peak times. An incentive for major customers to generate electricity is provided through our pricing structure which includes an avoidable control period demand charge.

6.4.5.3 Uneconomic connections policy

When an application for a new or upgraded larger connection is requested, we undertake an economic assessment of the connection. This assessment determines whether our standard pricing arrangements will cover the cost of utilising existing or new assets associated with the connection. If the connection is uneconomic, and existing customers would be subsidising the new connection, then a connection contribution is required from the new customer. This policy ensures that the true cost of providing supply is passed on to the appropriate customer and allows them to make the right financial trade-offs.

6.5 Network gap analysis

We analyse the network for gaps using our Security of Supply Standard. It is a guide to the level of capital investment required in future network expansion to deliver the desired level of reliability performance expected by connected customers. The standard provides a sound basis for balancing the cost of providing the service with the value placed on that service by the customer.

Our 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 will, or will not, occur following an asset failure and if so the length of time that customers can 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 the network planning 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 Table 6.5.2. Before implementing a major solution to eliminate a security gap, our network planning team ensures that the solution can be justified with economic analysis and a risk assessment.

In general, network security gaps fall into the following categories:

- solution is currently uneconomic, and an economic solution is not anticipated in the foreseeable future
- solution is currently uneconomic but is expected to become economic as load grows in the area under study
- local solution is uneconomic but network expansion in adjacent areas is expected to provide a security improvement in the future
- solution requires co-ordination with Transpower’s asset replacement programme and/or is subject to Transpower/Commerce Commission approval

The economic analysis we undertake when considering investments to improve network security take into account the High Impact Low Probability (HILP) nature of the risks involved.

Transpower is required to maintain an N-1 level of security for the core grid as stated in the Electricity Industry Participation Code which includes a national transmission grid reliability standard. The GXP gaps identified in Table 6.5.1 are based on the application of our Security of Supply Standard to Transpower’s core-grid, spur or GXP assets.

6.5 Network gap analysis continued

Table 6.5.1 and Table 6.5.2 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 6.5.1 Transpower GXP security gaps

GXP	Network gap	Solution	Proposed date
Islington	Partial loss of restoration for an Islington 220/33kV dual transformer failure	Long-term solution of upgrading Shands Rd ZS is not within the 10-year programme	TBA
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 is not within the 10-year programme	TBA

Table 6.5.2 Subtransmission network security gaps

Substation	Network gap	Solution	Proposed date
Dallington	Loss of 27MW 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 27MW 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 replacement. Project 1064	FY27
Waimakariri	Loss of 23MW of load for a single 66kV circuit	Complete a 66kV loop from Papanui via Belfast and Waimakariri. Projects 491 and 942	FY28
Lancaster	Loss of 19MW 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	FY25
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. Projects 940, 941 and 946	FY23

6.6 Network development proposals

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 6.4.1.

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.

6.6.1 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 five main programmes of work scheduled in the 10-year period:

- Northern Christchurch network, Section 6.6.1.1
- Region B 66kV subtransmission capacity, Section 6.6.1.2
- Region A 66kV subtransmission resilience, Section 6.6.1.3
- Lincoln area capacity and resilience improvement, Section 6.6.1.4
- Rolleston area capacity and resiliency, Section 6.6.1.5

The following Region A and Region B maps indicate the location and timing of individual forecast projects in this 10-year period, and the details of each project follow.

Our network development projects are driven by a variety of factors such as customer need, load growth, environmental considerations and increasing overall network resilience.

Figure 6.6.1 Region A subtransmission 66kV and 33kV – existing and proposed

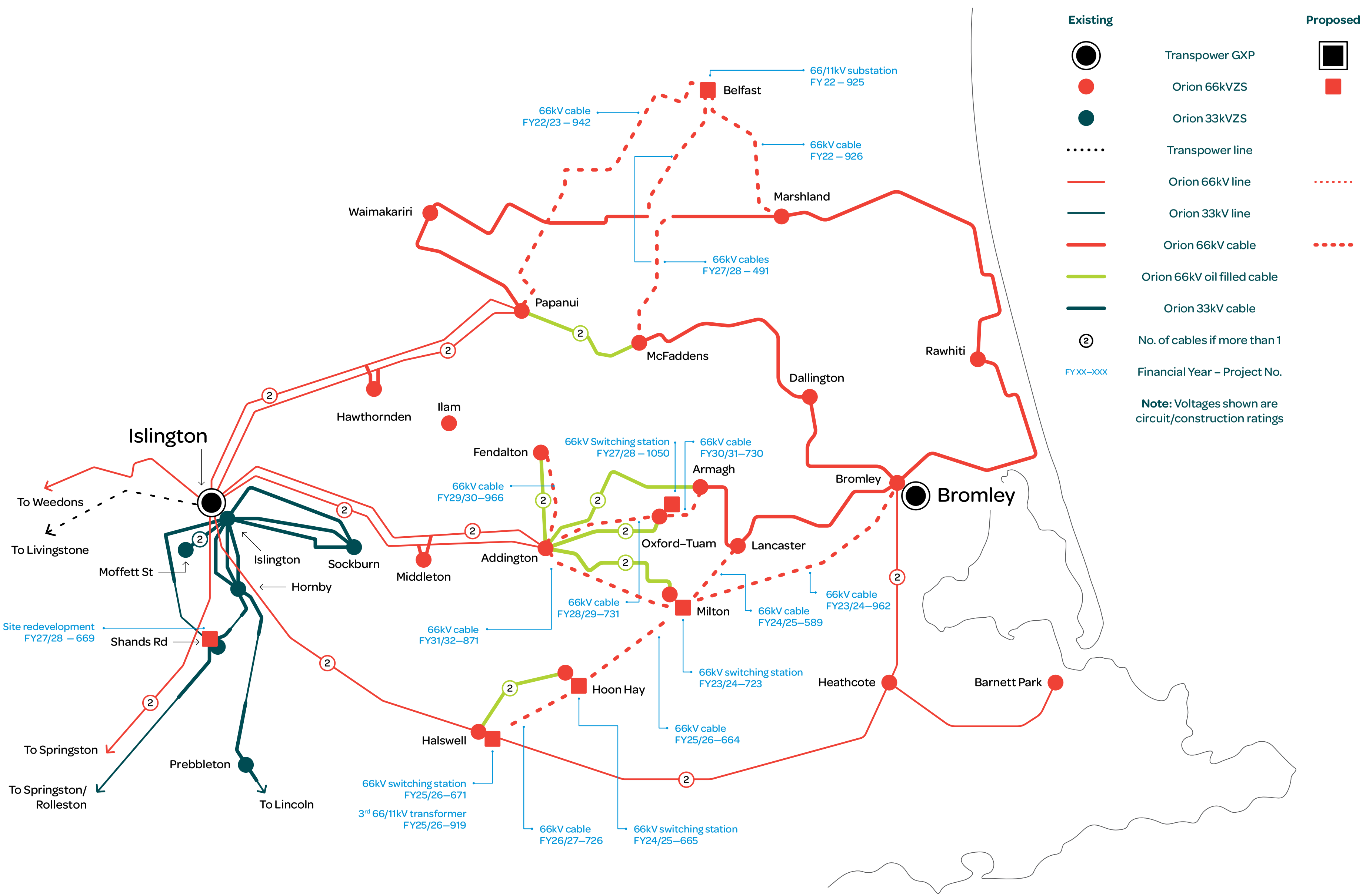
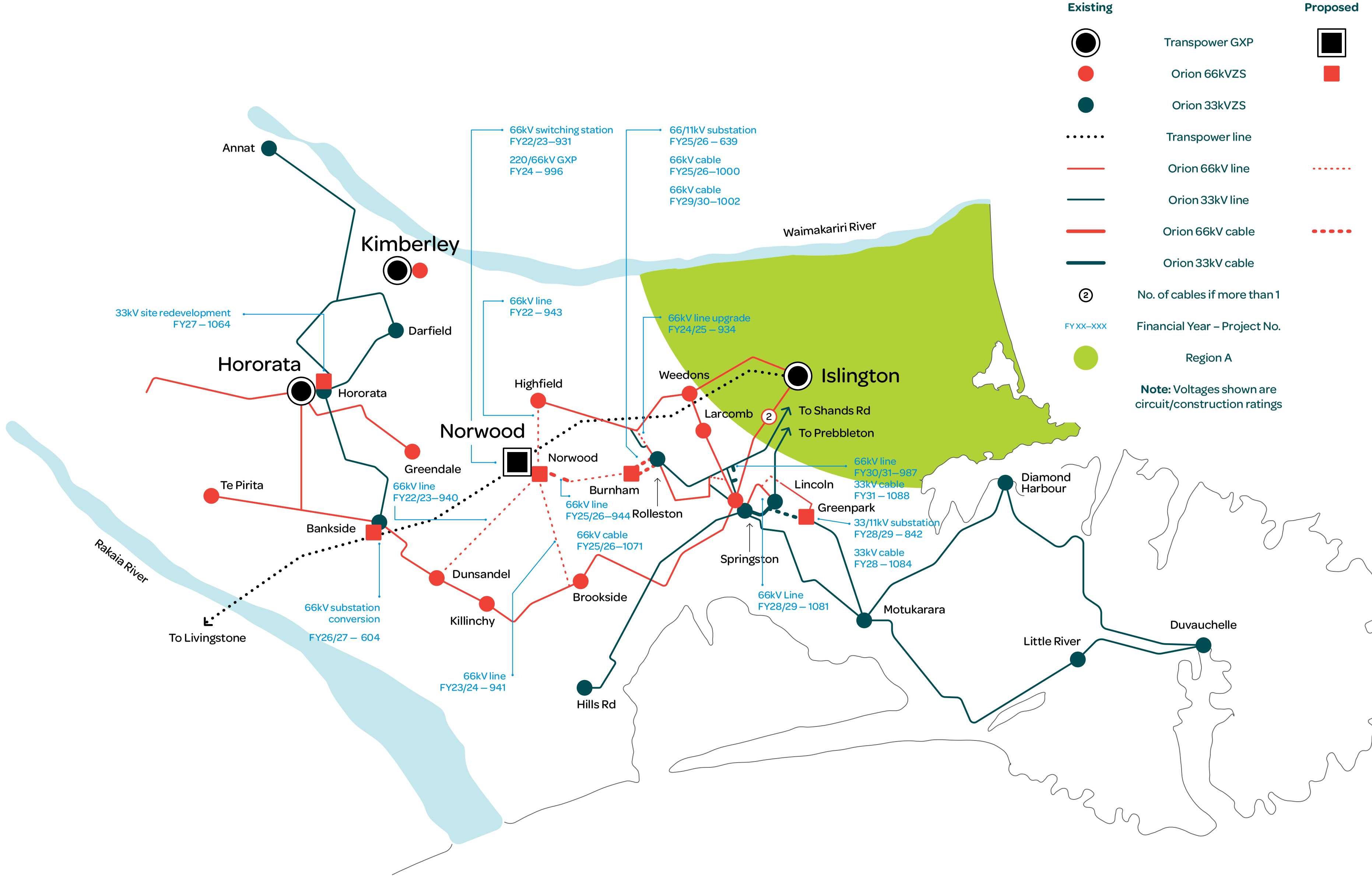


Figure 6.6.2 Region B subtransmission 66kV and 33kV – existing and proposed



6.6 Network development proposals continued

6.6.1.1 Northern Christchurch network

Strategic drivers

The CCC District Plan promotes Belfast as a priority area for business development and significant growth is likely now that the new northern motorway is constructed. For the last nine months the 11kV capacity in the Belfast area has been fully committed, due to the newly connected load being well above forecast average anticipated load density for the land zoning. The neighbouring Grimseys-Winters and Papanui zone substations are now highly loaded.

Presently, Orion's Dallington and Rawhiti zone substations are fed on open-ring 66kV supplies so are identified as posing a risk to reliability as they are vulnerable to complete outages for single cable faults.

We investigated non-traditional reinforcement using Distributed Energy Resources (DER), however the base load industrial and winter peaking loads combined with steady commercial and residential growth in Belfast mean that using other sources such as generators to meet expected loads is not feasible. Diesel generation is also at odds with Orion's commitment to reducing its carbon emissions and the rate of load growth also makes it unsuitable for grid scale battery storage. 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 Belfast area. Alternative customer demand management options were discounted due to not being able to reliably service the load growth in northern Christchurch with the current adoption of suitable technologies.

This programme of works addresses the 11kV distribution shortfall with the construction of a new zone substation, Project 925. Further projects reconfigure our 66kV Northern Loop to supply the new substation and to complete the 66kV ring supply to Dallington, Rawhiti and Waimakariri ZSs introducing greater reliability and resiliency.

An overview of the HV major and minor projects in the Northern Christchurch programme is outlined in Table 6.6.1.

Table 6.6.1 Northern Christchurch network – HV major projects

No.	Project title		Year	Business case (yes/no)
925	**Belfast ZS – new 66/11kV substation**		**FY22**	**Yes**
	Issue	Further 11kV capacity is required in the Northern Christchurch area to support the existing and forecast future load.		
	Chosen solution	Establish new 40 MVA 66/11 kV zone substation in Belfast to supply load growth in Northern Christchurch.		
	Remarks/alternatives	Other network options were investigated, but they were found impractical to supply the load growth using 11kV from existing zone substations or the previously proposed Marshland ZS due to the distribution reinforcement required.		
926	**Belfast ZS to Marshland switching station 66kV cable**		**FY20-22**	**Yes**
	Issue	The new Belfast ZS in the north of Christchurch requires a 66kV supply. Currently the nearest 66kV supply is the top part of the Northern Loop (Waimakariri ZS – Rawhiti ZS).		
	Chosen solution	This project establishes a 66kV cable link between the newly commissioned Marshland 66kV switching station and Belfast ZS. Project 925.		
	Remarks/alternatives	There are no other practical ways to supply Belfast ZS at 66kV without comprising the supply to existing zone substations.		
942	**Belfast ZS to Papanui ZS 66kV cable**		**FY22-23**	**Yes**
	Issue	Initially only a single 66kV cable connection will supply the new Belfast ZS (Project 925) providing only N security.		
	Chosen solution	This project creates a 66kV cable link between Belfast ZS and Papanui ZS. To provide switchable N-1 to Belfast ZS.		
	Remarks/alternatives	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.		
945	**Papanui ZS 66kV bay for Belfast ZS cable**		**FY22-23**	**Yes**
	Issue	Papanui ZS requires an extra bay to terminate the new Belfast ZS to Papanui ZS cable (Project 942).		
	Chosen solution	This project is to install and commission a new 66kV bay at Papanui ZS.		
	Remarks/alternatives	On completion of this project and Project 942, Belfast ZS will have switchable N-1 security at 66kV.		
491	**Belfast ZS to McFaddens ZS 66kV cable links**		**FY27-28**	**Yes**
	Issue	The supplies to Belfast ZS, Dallington ZS, Rawhiti ZS and Waimakariri ZS have only switchable N-1 security at 66kV.		
	Chosen solution	This project establishes 66kV cable links from Belfast ZS to Waimakariri ZS and from Marshland 66kV switching station to McFaddens ZS.		
	Remarks/alternatives	Belfast ZS, Dallington ZS, Rawhiti ZS and Waimakariri ZS will have full N-1 security at 66kV on completion of this cable link project.		

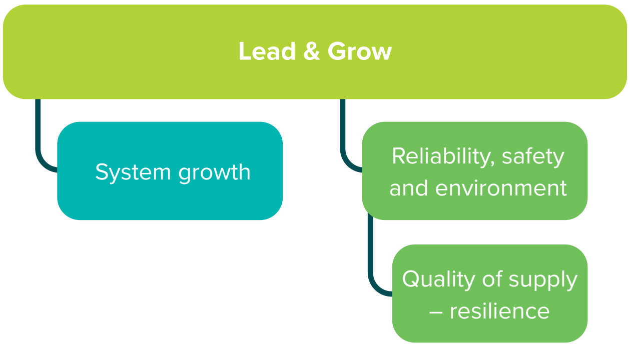
6.6 Network development proposals continued

Table 6.6.2 Northern Christchurch network – HV minor projects

No.	Project title		Year	Business case (yes/no)
983	**Belfast ZS 11kV feeders**		**FY22**	**Yes**
	Issue	A new Belfast ZS is to be constructed (Project 925), but there is no connectivity to the surrounding 11kV network.		
	Chosen solution	This project is the laying and commissioning of new 11kV feeders out of Belfast ZS to connect into the distribution network on Belfast and Blakes Rd. This includes the reconfiguration at multiple sites to ensure that the new substation capacity can be utilised.		
	Remarks/alternatives	Alternative topologies were explored to reconfigure the existing closed-ring 11kV network but were less cost effective and did not achieve the required outcomes for contingency switching.		
1055	**Papanui 11kV primary reconfiguration**		**FY23**	**No**
	Issue	The network in the north of Christchurch is supplied from Papanui ZS via an 11kV primary feeder group with six feeders operating in parallel. To ensure safety is maintained for all faults on a the 11kV primary feeder group, a multi-feeder protection scheme has been installed at Papanui ZS. The resilience of this network is poor because any downstream busbar, CB or relay failure will result in a loss of supply to all six feeders.		
	Chosen solution	With the completion of Belfast ZS there is now an opportunity to reconfigure the six-feeder primary. The proposed works splits the lower part of the six-feeder primary into two three feeder primaries. This rearrangement, including the unloading of the top of the primary feeder onto Belfast ZS, greatly reducing the quantity of customers exposed to an outage caused by a failure of a downstream component.		
	Remarks/alternatives	This work increases the resiliency of the feeder group and increases the reliability to Grampian St substation. This project will be completed in-conjunction with an 11kV switchgear replacement at Grimseys Rd. No.187.		

6.6.1.2 Region B 66kV subtransmission capacity

Strategic drivers



Continued residential and commercial growth around the areas of Rolleston, Lincoln and growth from major consumers will cause load on the Islington – Weedons – Larcomb – Springston 66kV (Western) Loop to exceed firm capacity around FY23. Commercial and residential load growth in the central city, Halswell, Rolleston and Lincoln as well as large industrial and commercial developments in Belfast and at Dunsandel ZS are driving the constraint.

The resilience of the subtransmission supply to Region B is currently limited by the supply at Islington 66kV, the generation from Trustpower's Lake Coleridge and the 66kV subtransmission capacity. The 66kV subtransmission circuit between Hororata and Springston has been identified as a network security gap. With the load on this circuit exceeding 15MVA, our Security of Supply Standard requires that a fault on a single cable, line or transformer causes no interruption of supply to customers which is not currently achievable. It should also be noted that the primary supply to a major consumer from Dunsandel ZS is voltage drop and thermally constrained.

We investigated solutions to address the Islington 66kV GXP constraints such as increasing capacity at Bromley GXP and shifting some Islington GXP load to Bromley GXP. They will fix the Islington 66kV GXP issue but will not address the other issues that have been identified. 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. Distributed Energy Resources, for example solar, are better suited to deferring investment in a slowly developing load environment. The growth rate expected in Region B means this is not a good candidate.

The chosen solution to address all these issues is to install a new 220/66kV GXP at Norwood that is supplied from the Transpower Islington-Livingstone 220kV circuit.

Projects that form the Region B 66kV subtransmission capacity programme of works are outlined in Table 6.6.3.

Table 6.6.3 Region B 66kV subtransmission capacity – GXP projects

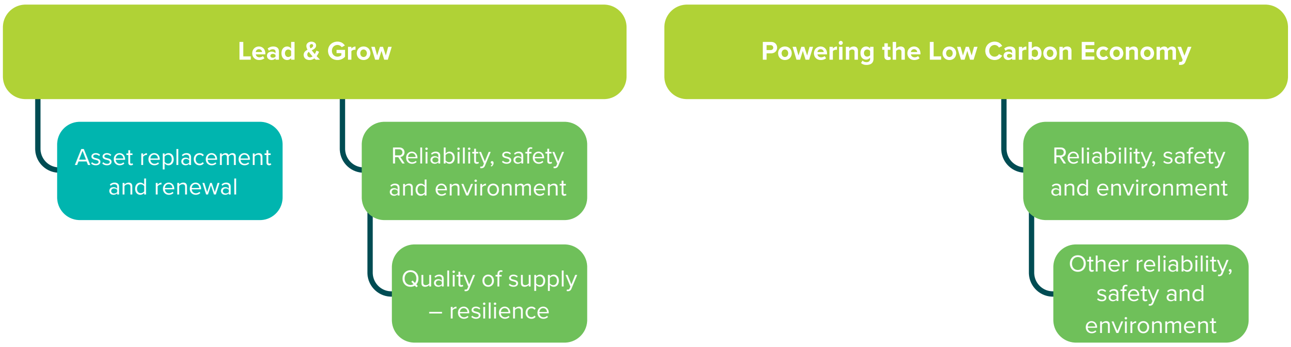
No.	Project title		Year	Business case (yes/no)
996	**Norwood GXP - new Region B 220/66kV substation**		**FY24**	**Yes**
	Issue	The 66kV capacity supplying Region B is becoming constrained due to rapid growth in this area, with the Western Loop forecast to exceed firm capacity around FY23.		
	Chosen solution	Install a new 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.		

Table 6.6.4 Region B 66kV subtransmission capacity – HV major projects

No.	Project title		Year	Business case (yes/no)
931	**Norwood ZS 66kV**		**FY22-23**	**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	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**		**FY22-23**	**Yes**
	Issue	The existing 66kV subtransmission 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**		**FY23-24**	**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 giving an uninterrupted N-1 supply to Dunsandel ZS and Killinchy ZS. The new line will tee into the existing Brookside ZS to Killinchy ZS 66kV line so no additional 66kV CB bay will be required at Brookside 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.		
946	**Dunsandel ZS 66kV line bay**		**FY22-23**	**Yes**
	Issue	A new 66kV CB bay is required at Dunsandel ZS to terminate the new 66kV line from Norwood ZS (Project 940).		
	Chosen solution	The existing 66kV ring-bus at Dunsandel ZS was originally designed and constructed for additional 66kV bays to be added. This project is the purchase, construction and commissioning of a new 66kV bay to terminate the new 66kV line from Norwood ZS.		
	Remarks/alternatives	Refer to Project 931 for the construction of the 66kV busbar at Norwood ZS.		

6.6.1.3 Region A 66kV subtransmission resilience

Strategic drivers



To increase our urban 66kV subtransmission network's resilience against the impact of a major seismic event, we have developed a 10-year programme to replace our remaining 40km of 66kV oil filled underground cables commencing in FY24. This programme also incorporates forecast network growth and lifecycle replacement projects as well as other resilience initiatives across our Region A 66kV network. These projects all form part of our network development plans.

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 are far beyond the energy storage capability of existing known Distributed Energy Resource (DER) systems during winter peak load times.

This programme 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 this the 10-year plan are outlined in Tables 6.6.5 and 6.6.6:

Table 6.6.5 Region A 66kV subtransmission resilience – HV major projects

<table>
<tr><th>No.</th><th colspan="2">Project title</th><th>Year</th><th>Business case (yes/no)</th></tr>
<tr><td>723</td><td colspan="2">Milton ZS 66kV switchgear and building</td><td>FY23-24</td><td>No</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">The Milton ZS to Lancaster ZS 66kV cable (Project 589) will require switchgear installation at Milton ZS.</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">This project is for the purchase of the 66kV switchgear, construction of a new 66kV switchroom, installation and commissioning at Milton ZS.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">This switching station is located on a pivotal intersection of the proposed 66kV network providing future GXP load management capability.</td></tr>
<tr><td>962</td><td colspan="2">Bromley ZS to Milton ZS 66kV cable</td><td>FY23-24</td><td>Yes</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">As part of the 66kV oil filled cable replacement 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.</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">This project is to purchase, install and commission a new 66kV cable between Bromley ZS and the new Milton ZS 66kV switchroom, Project 723.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">The Bromley ZS 66kV bay for this project is the ex-Lancaster ZS feeder bay 170.</td></tr>
<tr><td>665</td><td colspan="2">Hoon Hay ZS 66kV switchgear and building</td><td>FY24-25</td><td>Yes</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">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 replacement 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.</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">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).</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">The new building will fit within the existing Hoon Hay ZS site, but further land acquisition is needed to meet building set-back requirements.</td></tr>
</table>

Table 6.6.5 Region A 66kV subtransmission resilience – HV major projects (continued)

<table>
<tr><th>No.</th><th colspan="2">Project title</th><th>Year</th><th>Business case (yes/no)</th></tr>
<tr><td>589</td><td colspan="2">Lancaster ZS to Milton ZS 66kV cable</td><td>FY24-25</td><td>Yes</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">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.</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">A new 66kV cable between Lancaster and Milton zone substations will provide extra security of supply for the CBD.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">This cable link was envisaged as part of our post-earthquake 2012 subtransmission architecture review.</td></tr>
<tr><td>671</td><td colspan="2">Halswell ZS 66kV switchgear and building</td><td>FY25-26</td><td>Yes</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">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.</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">This project is the construction and commissioning of a new 66kV ring-bus switchroom and adjoining 11kV switchroom and transformer pad for the 3rd transformer at Halswell ZS. See Project 919 for the purchase, install and commissioning of 3rd 11kV bus section and new 23MVA transformer.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">This project has been timed to coincide with lifecycle replacement of four 66kV CBs at Halswell ZS. Also, the new 66kV bus arrangement will be built with allowance for a new 3rd transformer to be easily connected (Project 919) to increase the 11kV capacity of Halswell ZS.</td></tr>
<tr><td>664</td><td colspan="2">Milton ZS to Hoon Hay ZS 66kV cable</td><td>FY25-26</td><td>Yes</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">To facilitate the new Region A 66kV architecture as part of the 66kV oil filled cable replacement programme a cable connection between Milton ZS and Hoon Hay ZS is required.</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">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).</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">This project is part of an over-arching Region A architecture plan and strategic 66kV cable replacement programme</td></tr>
<tr><td>726</td><td colspan="2">Halswell ZS to Hoon Hay ZS 66kV cable</td><td>FY26-27</td><td>Yes</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">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.</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">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).</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">This project will provide Hoon Hay ZS with a full N-1 66kV supply with diverse supply routes.</td></tr>
</table>

Table 6.6.5 Region A 66kV subtransmission resilience – HV major projects (continued)

<table>
<tr><th>No.</th><th colspan="2">Project title</th><th>Year</th><th>Business case (yes/no)</th></tr>
<tr><td>872</td><td colspan="2">Addington ZS 66kV bay and bus couplers</td><td>FY26-27</td><td>Yes</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">Addington ZS currently operates the 66kV busbar split with each of the six substations having a feed from each side of the bus. The proposed Region A architecture moves to a closed-ring design that requires three 66kV bus sections with bus couplers.</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">This project is the purchase, construction and commissioning of the 66kV switchgear to create the new low-profile centre bus section.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">This project is part of an over-arching Region A architecture plan and strategic 66kV cable replacement programme. The new 66kV bus design is also timed to coordinate with the 66/11kV transformer replacement at Addington ZS.</td></tr>
<tr><td>1050</td><td colspan="2">Oxford-Tuam ZS 66kV switchgear and building</td><td>FY27-28</td><td>No</td></tr>
<tr><td>731</td><td colspan="2">Addington ZS to Oxford-Tuam ZS 66kV cable</td><td>FY28-29</td><td>No</td></tr>
<tr><td>966</td><td colspan="2">Addington ZS to Fendalton ZS T1 66kV cable</td><td>FY29-30</td><td>No</td></tr>
<tr><td>730</td><td colspan="2">Armagh ZS to Oxford Tuam ZS 66kV cable</td><td>FY30-31</td><td>No</td></tr>
<tr><td>871</td><td colspan="2">Addington ZS to Milton ZS 66kV cable</td><td>FY31-32</td><td>No</td></tr>
</table>

6.6.1.4 Lincoln area capacity and resilience improvement

Strategic drivers

High residential subdivision growth in the Lincoln township has pushed the peak load of Lincoln Zone Substation (ZS) beyond the firm capacity by approximately 0.5MVA. By FY31 this load is forecast to be approximately 130% of the site's firm capacity. Springston ZS also provides support for the Lincoln township and due to the additional commercial growth, is forecast to breach its capacity in FY24. This substation is expected to be approximately 150% of the site's firm capacity by FY31. If unaddressed, this situation puts the area at risk of a cascade failure, black-out fault, during peak load times.

We considered non-network alternatives but Distributed Energy Resources, for example solar, are better suited to deferring investment in a slowly developing load environment. The growth rate expected in the Lincoln area and the winter peaking aspect means it is not a good candidate.

The projects in Table 6.6.6 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.

6.6 Network development proposals continued

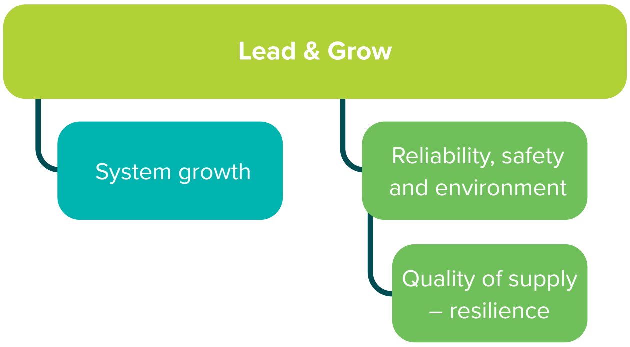
Table 6.6.6 Lincoln area capacity and resilience improvement – HV major projects

<table>
<tr><th>No.</th><th colspan="2">Project title</th><th>Year</th><th>Business case (yes/no)</th></tr>
<tr><td>894</td><td colspan="2">Springston ZS 2nd 66/11kV transformer bank</td><td>FY23-24</td><td>No</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">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).</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">We will increase the capacity by installing a second 66/11kV transformer and additional 66kV CB bay.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">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 substation.</td></tr>
<tr><td>728</td><td colspan="2">Springston ZS 11kV switchboard extension</td><td>FY23-24</td><td>Yes</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">At Springston ZS additional 11kV circuit breakers are required to connect the new 66/11kV transformer (Project 894).</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">This project extends the 11kV CB's installed in FY18 to terminate the new transformer and provide additional feeders.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">The 11kV CBs located within the modular building will be decommissioned as part of this project.</td></tr>
<tr><td>1099</td><td colspan="2">Springston ZS 66/11kV transformer upgrade</td><td>FY25-26</td><td>No</td></tr>
<tr><td></td><td>Issue</td><td colspan="3">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.</td></tr>
<tr><td></td><td>Chosen solution</td><td colspan="3">Change the existing T3 66/11kV 10MVA transformer to a new 11.5/23MVA transformer.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="3">This upgrade prolongs the need to construct the Greenpark substation.</td></tr>
<tr><td>1080</td><td colspan="2">Springston to Lincoln ZS 66kV line reconductor</td><td>FY28</td><td>No</td></tr>
<tr><td>1084</td><td colspan="2">Edward St 33kV cable</td><td>FY28</td><td>No</td></tr>
<tr><td>842</td><td colspan="2">Greenpark 33kV zone substation</td><td>FY28-29</td><td>No</td></tr>
<tr><td>1081</td><td colspan="2">Tancreds and Springs Rd 66kV line</td><td>FY28-29</td><td>No</td></tr>
</table>

6.6 Network development proposals continued

6.6.1.5 Rolleston area capacity and resiliency

Strategic 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 substations of Larcomb and Weedons ZS have been exhausted.

This continued growth also effects the subtransmission supplying this area and it is forecast that the firm capacity of the Islington GXP – Weedons ZS – Larcomb ZS – Springston 66kV (Western) Loop will be exceeded around FY23.

This programme of works addresses the local 11kV distribution capacity with the establishment of a new higher capacity substation to replace Rolleston ZS.

The programme of works also outlines the projects that develop the 66kV diverse route subtransmission closed-loop supply from Norwood ZS to the new substation. Options to supply the new substation from either the existing 33kV network or reinsulating the remaining 33kV to 66kV lines to complete the ring fed from Weedons and Springston ZS were investigated, but they do not address the impending 66kV subtransmission constraint on the Western Loop.

Table 6.6.7 Rolleston area capacity and resiliency – HV major projects

No.	Project title		Year	Business case (yes/no)
943	**Highfield ZS to Norwood ZS 66kV line**		**FY22**	**Yes**
	Issue	An existing major customer is increasing their load beyond the existing 11kV distribution capacity.		
	Chosen solution	The combined load on Islington 66kV GXP is also forecast to exceed firm capacity in FY27.		
	Remarks/alternatives	This project utilises the thermal capacity of the Highfield ZS transformer to supply the customer demand at 11kV via the new 66kV insulated line prior to the construction of Norwood 66/11kV zone substation (Project 1070).		
934	**Walkers Rd 66kV line conversion**		**FY24-25**	**No**
	Issue	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.		
	Chosen solution	This project converts the remaining 33kV line construction, down Walkers Rd, between Two Chain Rd and Kerrs/Wards Rd, to 66kV construction.		
	Remarks/alternatives	This project coordinates with other projects to meet the requirement of creating a 66kV ring out of Norwood ZS to supply the new Burnham ZS.		
953	**Norwood ZS 66kV line bays**		**FY24-25**	**No**
	Issue	The load on the Islington - Weedons - Larcomb - Springston 66kV loop is forecast to exceed capacity in FY24. The load on Islington 66kV is also forecast to exceed capacity in FY27.		
	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.		
	Remarks/alternatives	The timing of this project is to ensure the resource required to construct the final solution is smoothed-out over several years.		

6.6 Network development proposals continued

Table 6.6.7 Rolleston area capacity and resiliency – HV major projects (continued)

No.	Project title		Year	Business case (yes/no)
954	**Highfield ZS 66kV line bays**		**FY24 - 25**	**No**
	Issue	The load on the Islington - Weedons - Larcomb - Springston 66kV loop is forecast to exceed capacity in FY24. The load on Islington 66kV is also forecast to exceed capacity in FY27.		
	Chosen solution	This project installs two new 66kV line bays at Highfield ZS to allow for the connection of the new 66kV line from Norwood ZS. See Project 943.		
	Remarks/alternatives	The timing of this project is to ensure the resource required to construct the final solution is smoothed-out over several years.		
639	**Burnham ZS – new 66/11kV substation**		**FY25-26**	**No**
	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 (Projects 931 and 944)		
	Chosen solution	A new 66/11kV 23MVA capacity Burnham ZS will be built to replace the 33/11kV 10MVA capacity at Rolleston 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. This project also shifts load off the Islington 66kV GXP onto the new Norwood GXP relieving the upper network capacity, see Project 944 for details		
944	**Burnham ZS to Norwood ZS 66kV line**		**FY25-26**	**No**
	Issue	A full N-1 66kV supply will be required at the planned Burnham ZS (Project 639) due to the existing load on Rolleston ZS.		
	Chosen solution	This project, in-conjunction with the Norwood ZS to Telegraph / Two Chain Rd corner 66kV cable circuit (Project 1071), creates a new 66kV link between Norwood ZS (Project 931) and Burnham ZS (Project 639). This will form part of the 66kV subtransmission loop Norwood ZS - Highfield ZS - Burnham ZS. This provides Burnham ZS with a full N-1 loop out of Norwood ZS.		
	Remarks/alternatives	Supplying the new Burnham ZS from Springston ZS at 33kV or the Islington GXP – Weedons ZS – Larcomb ZS – Springston ZS 66kV loop were investigated, but these solutions do not provide the same additional resiliency for the Islington GXP – Weedons ZS – Larcomb ZS – Springston ZS 66kV loop or Islington GXP 66kV.		
1000	**Burnham ZS to Dunns Crossing Rd 66kV cable**		**FY25-26**	**No**
	Issue	The area surrounding the proposed Burnham ZS (Project 639) 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 to provide a N-1 supply.		
	Chosen solution	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 part of the connection back to Norwood ZS via Highfield ZS.		
	Remarks/alternatives	An overhead line option was considered but is not suitable due to the proximity of the school and houses.		
1071	**Norwood ZS to Telegraph / Two Chain Rd cnr 66kV cable**		**FY25-26**	**No**
	Issue	A full N-1 66kV supply will be required at the planned Burnham ZS (Project 639) due to the existing load on Rolleston ZS.		
	Chosen solution	This project, in-conjunction with the Norwood ZS to Burnham 66kV line (Project 944), creates a new 66kV link between Norwood GXP (Project 931) and Burnham ZS (Project 639). This will form part of the 66kV subtransmission loop Norwood ZS – Highfield ZS – Burnham ZS. This provides Burnham ZS with a full N-1 loop out of Norwood ZS.		
	Remarks/alternatives	This part of the Norwood ZS to Burnham ZS 66kV circuit could not be constructed as O/H due to existing assets in the same corridor.		

6.6.1.6 Other network development proposals

Table 6.6.8 Other network development proposals – HV major projects

<table>
<tr><th>No.</th><th colspan="2">Project title</th><th>Year</th><th>Strategic drivers</th><th>Business case (yes/no)</th></tr>
<tr><td rowspan="4">919</td><td colspan="2">Halswell ZS 3rd transformer and 11kV switchgear</td><td>FY25-26</td><td>Lead & Grow
System growth</td><td>No</td></tr>
<tr><td>Issue</td><td colspan="4">High residential growth in the southwest of Christchurch has meant that the 11kV capacity is close to the N-1 limit between Halswell ZS and Hoon Hay ZS.</td></tr>
<tr><td>Chosen solution</td><td colspan="4">Purchase, install and commission 3rd transformer and new 11kV switchgear for 3rd bus section. See project 671 for the 11kV switchroom and 23MVA transformer pad construction.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="4">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 11kV switchgear under this option and the future 66kV running arrangement.</td></tr>
<tr><td rowspan="4">1070</td><td colspan="2">Norwood 66/11kV zone substation</td><td>FY24-25</td><td>Customer Inspired
Customer connection
Lead & Grow
Quality of supply / Resilience</td><td>No</td></tr>
<tr><td>Issue</td><td colspan="4">An existing major customer is increasing their load beyond the existing 11kV distribution capacity between Highfield ZS, Rolleston ZS and Greendale ZS. After the completion of Burnham ZS (Project 639) the Highfield ZS to Norwood ZS 66kV line (Project 943) will be required to operate at 66kV to create an N-1 supply for Highfield ZS and Burnham ZS. This means that the customer/s relying upon it for supply will no longer be able to.</td></tr>
<tr><td>Chosen solution</td><td colspan="4">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.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="4">There was the option to significantly reinforce the existing 11kV distribution network. However, to provide the required security of supply it would be less cost effective than the chosen solution. Distributed Energy Resources (e.g. Solar) are better suited to deferring investment in a slowly developing load environment. The higher growth rate expected in surrounding area means it is not a good candidate.</td></tr>
<tr><td rowspan="4">604</td><td colspan="2">Bankside ZS 33kV to 66kV conversion</td><td>FY26-27</td><td>Lead & Grow
Other reliability, safety and environment</td><td>No</td></tr>
<tr><td>Issue</td><td colspan="4">The Hororata 33kV load has exceeded the Hororata 33kV GXP N-1 capacity at summer peak load periods putting >23MVA at risk of cascade failure if a single transformer fault was to occur.</td></tr>
<tr><td>Chosen solution</td><td colspan="4">Convert Bankside to 66kV by replacing the existing transformer and reconfiguring the switchyard for two new 66kV bays.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="4">Options to relieve the 33kV constraint via 11kV load transfers have been exhausted and further shifts would significantly affect the 11kV reliability due to excessively large feeders. With conversion to 66kV comes the requirement to install an 11kV ripple plant. It is proposed that the ex-Harewood ripple plant transportable building and associated equipment are relocated to provide this. This project should be completed before proceeding with the 33kV switchgear replacement at Hororata ZS, see Project 1064 removing the need for an additional bay.</td></tr>
</table>

6.6 Network development proposals continued

Table 6.6.8 Other network development proposals – HV major projects (continued)

No.	Project title	Year	Strategic drivers	Business case (yes/no)
669	**Shands Rd ZS site redevelopment**	**FY27-28**	**Lead & Grow** Asset replacement and renewal **Lead & Grow** System growth	**No**
1064	**Hororata ZS 33kV site redevelopment**	**FY27**	**Lead & Grow** Asset replacement and renewal **Lead & Grow** System growth	**No**
1001	**Burnham ZS 66kV bay**	**FY29-30**	**Lead & Grow** System growth	**No**
1095	**Wards Rd 66kV line reconductor**	**FY30**	**Lead & Grow** System growth	**No**
1002	**Burnham School Rd 66kV cable**	**FY29-30**	**Lead & Grow** System growth	**No**
987	**Lincoln Rolleston Rd 66kV line**	**FY30-31**	**Lead & Grow** System growth	**No**
1088	**Weedons Rd 33kV cable**	**FY31**	**Lead & Grow** System growth	**No**
1096	**West Melton – Newtons Rd 66kV line thermal upgrade**	**FY31**	**Lead & Grow** System growth	**No**

6.6 Network development proposals continued

Table 6.6.9 Other network development proposals – HV minor projects

<table>
<tr><th>No.</th><th colspan="2">Project title</th><th>Year</th><th>Strategic drivers</th><th>Business case (yes/no)</th></tr>
<tr><td rowspan="4">922</td><td colspan="2">Milton ZS 11kV alteration</td><td>FY22</td><td>Lead & Grow
System growth</td><td>Yes</td></tr>
<tr><td>Issue</td><td colspan="4">The Milton ZS configuration does not allow the 11kV incomer cables to share equally. This was a particular problem during a transformer outage where one of the remaining sets would reach the thermal capacity well before the transformer was fully loaded derating the substation firm capacity.</td></tr>
<tr><td>Chosen solution</td><td colspan="4">This project allows for the installation and commissioning of a cabled wrap-around bus tie, including the bus coupler circuit breakers.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="4">We investigated upgrading the incomer cables but discounted this option due to limitations in other parts of the thermal chain.</td></tr>
<tr><td rowspan="4">1069</td><td colspan="2">Two Chain Rd reinforcement</td><td>FY22</td><td>Customer Inspired
Customer connection
Lead & Grow
Quality of supply / Resilience</td><td>Yes</td></tr>
<tr><td>Issue</td><td colspan="4">An existing major customer is increasing their load beyond the existing 11kV distribution capacity between Highfield ZS, Rolleston ZS and Greendale ZS.</td></tr>
<tr><td>Chosen solution</td><td colspan="4">This project constructs a new circuit down Two Chain Rd, plus some minor works at Highfield ZS to create a new 11kV feed point.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="4">The new circuit down Two Chain Rd consists of 1.85km of new 11kV line and 1.9km of underground cable.</td></tr>
<tr><td rowspan="4">986</td><td colspan="2">Weedons ZS new feeder (Knights Road)</td><td>FY22</td><td>Customer Inspired
Customer connection</td><td>Yes</td></tr>
<tr><td>Issue</td><td colspan="4">A new major customer in Izone business park are building a factory with significant load requirements in 2021. There is currently insufficient 11 kV network capacity for the increase.</td></tr>
<tr><td>Chosen solution</td><td colspan="4">The chosen solution is to lay a new 11 kV feeder from Weedons zone substation to Izone to reinforce the area and to meet the customer requirements.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="4">Reinforcing the 11kV network from Larcomb Zone Substation was investigated, but there is currently cable route limitations and this option does not align with the trunk feeder architecture for the Rolleston area.</td></tr>
<tr><td rowspan="4">997</td><td colspan="2">Coleridge generator connection & reliability improvement</td><td>FY22</td><td>Lead & Grow
Quality of supply / Resilience</td><td>Yes</td></tr>
<tr><td>Issue</td><td colspan="4">Recent faults on the Coleridge overhead network have highlighted various issues, including protection coordination and access difficulties during storms due to the terrain, which lead to prolonged outages.</td></tr>
<tr><td>Chosen solution</td><td colspan="4">Install new distribution switchgear with protection downstream of Coleridge GXP to provide a generator connection point and improved reliability.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="4">Install a new kiosk outside Coleridge GXP to provide a generator connection point. Replace manual ABIs with remote controlled line switches. These do not provide the full reliability or protection grading benefits of the preferred option.</td></tr>
<tr><td rowspan="4">1066</td><td colspan="2">Burdons Road reinforcement</td><td>FY22</td><td>Customer Inspired
Customer connection</td><td>Yes</td></tr>
<tr><td>Issue</td><td colspan="4">A large customer west of Rolleston have indicated that they would like to increase their load by 1.5 MVA by March 2022. This would result in the overhead line down Burdons Rd becoming overloaded.</td></tr>
<tr><td>Chosen solution</td><td colspan="4">The chosen solution is to upgrade the overhead conductor down Burdons Rd to the next standard size conductor which is rated for approximately 5 MVA.</td></tr>
<tr><td>Remarks/alternatives</td><td colspan="4">The alternatives are to run a second overhead line down Burdons Rd or use generators to reduce the peak load. These options are either at least the same cost as the preferred solution or not practical given this is an N security constraint.</td></tr>
</table>

6.6 Network development proposals continued

6.6.2 LV projects

With ongoing residential infill in Christchurch city as well as new technologies such as electric vehicles and photovoltaic generation becoming more economical, the capability of our LV network is becoming increasingly important. To prepare for the future and help to facilitate customer choice, we are focussing on reinforcing vulnerable areas of our LV network and gaining more visibility of how our LV networks are being utilised.

Table 6.6.10 outlines our Network Development LV projects planned for the next 10 years.

Table 6.6.10 LV projects

No.	Project title	Year	Strategic drivers	Business case (yes/no)
384	**Unidentified LV reinforcement**	**FY22-31**	**Lead & Grow** System growth	**No**
	Issue	As new technologies emerge, we will start to see changes in the traditional usage patterns on our LV network. This may cause stress on some older areas of our LV network and require reinforcement to maintain service levels.		
	Chosen solution	Monitor residential infill, EV uptake, power quality and LV monitor readings to prioritise areas of LV network which require reinforcement.		
	Remarks/alternatives	We will investigate the use of non-network alternatives such as LV STATCOMs where appropriate. Some reinforcement may be able to be delayed with smart EV charging.		
884	**Low voltage monitoring**	**FY20-29**	**Reimaging the Future Network** System growth **Powering the Low Carbon Economy** Other reliability, safety and environment	**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 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.		

6.7 Value of Distributed Energy Resources Management alternatives

Distributed Energy Resources 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 funding available from Orion when specific projects are deferred through DERM.

Table 6.7.1 is a high-level assessment of the annual per kW cost of proposed network solutions 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 provides capacity for a 1MW security breach and 200kW of annual load growth. For a DERM solution to be economic it needs to provide at least one-year deferral of a network solution, and the cost per kW must be lower than $ listed below. If the DERM solution can provide three years of deferral (1.6MW at peak) then the DERM proposal cost must be lower than:

- $860/kW for 1.2MW in the first year
- $740/kW for 1.4MW in the second year
- $650/kW for 1.6MW in the third year

The values in Table 6.7.1 assume that the Distributed Energy Resources Management solution is provided in the year required.

Distributed Energy Resources Management (DERM) initiatives can provide alternatives to investment in traditional network development solutions.

Table 6.7.1 Distributed Energy Resources Management value for network development alternatives

No.	Project description	Year	Base constraint (kW)	Growth per year (kW)	$ per kW available for DERM		
					Year 1	Year 2	Year 3
894	Springston ZS 2nd 66/11kV transformer bank	FY24	3000	600	80	70	60
728	Springston ZS 11kV switchboard extension						
919	Halswell ZS 3rd transformer and 11kV switchgear	FY26	–	700	360	180	120
639	Burnham ZS - new 66/11kV substation	FY26	1000	200	1320	1130	990
944	Norwood GXP to Burnham ZS 66kV line						
1071	Norwood ZS to Telegraph / Two Chain Rd cnr 66kV cable						
1070	Norwood 66/11kV zone substation	FY25	2000	–	70	70	70

7

Managing our assets

Photo: Top of 66kV circuit breaker at our Heathcote zone substation.

Contents

Contents continued

7.1 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 5.6.

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 customers 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. Since the reliability contribution for poles and switchgear combined is less than 1 per cent of the network SAIDI and SAIFI, the increase in the replacement rate will have a direct but not material impact on our performance. The driver for these programmes is to continue addressing the potential safety consequences of asset failure.

Events that materially impact our network are weather events, vegetation and plant failure for example cable, insulator and conductor tail failure. We reduce the impact of these events by conducting regular proactive programmes where approximately 70 per cent of our network operational expenditure is spent on inspections, testing and vegetation management. The remaining 30 per cent is spent on responding to service interruptions and emergencies, the majority of which occur on our overhead network and are largely weather related.

Our assumptions listed in Section 2.13 mean we do not expect an upswing in the inspection / monitoring programmes expenditure. We expect the forecast expenditure for our maintenance and replacement strategies will maintain our overall performance at the current level without compromising important safety outcomes.

7.2 How this section is structured

In the following Sections 7.3 to 7.20 for each asset class we have taken a consistent approach to describing the assets, their current health, our plans for maintenance and replacement and any innovations that we are considering.

For each asset class we provide:

Summary

A summary of the main issues and plan for the asset class.

Asset description

A brief description giving the type, function, voltage levels and location of each asset class. The number of units will also be provided together with the age profile. Information on asset data management can be found in Section 2.12.2.

Asset Health

Condition

The asset's current condition, including its Health Index (HI) profile. An age profile is 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 CBRM process is described in Section 5.6.

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 ongoing day to day work plans that keep the asset serviceable and prevent premature deterioration or failure. A summary of the inspection, testing and maintenance and their 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.

Innovation

We discuss innovations that have deferred asset replacements, or those we are trialing which may be implemented if found to improve our current lifecycle asset management practices. This section is only provided for asset classes where it is relevant.

This section covers more than 11,700 buildings, substations, kiosks and land assets that form an integral part of Orion’s distribution network.

7.3 Network property

7.3.1 Summary

This section covers more than 11,700 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.

7.3.2 Asset description

7.3.2.1 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. Orion’s zone substations, see Table 7.3.1, 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 a ripple injection plant is installed.

Table 7.3.1 Zone substation description and quantity

Voltage	Quantity	Description
66kV	1	Marshland is a 66kV zone substation located in Region A
33kV	1	Islington is a 33kV zone substation that supplies the Region A 33kV / 11kV zone substation
66kV / 11kV	28	18 in Region A. 9 of those are urban substations and have an exposed bus structure. The Armagh, Dallington, Lancaster, McFaddens and Waimakariri structures are inside a building. 10 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 / 11kV	1	Springston rural zone substation is supplied by a 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. Capacity of these substations is split into three groups as follows: • Larger urban substations have two or three independent dual rated transformers • Smaller urban and larger rural substations have a pair of single rated transformers • Smaller rural substations have one single rated transformer 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**	

7.3.2.2 Distribution substation

The different types of our distribution substations are shown in Table 7.3.2. Where our equipment is housed in buildings, many are owned by our customers.

Table 7.3.2 Distribution substation type

Type	Quantity	Description
Building	248	The substation buildings vary in size and construction and 30% are Orion owned. All substations usually contain at least one transformer with an 11kV switch unit and 400V distribution panel
Kiosk	3,201	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	814	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	6,403	Single pole mounted substations usually with 11kV fusing and a transformer
Pad transformer	825	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	174	Cabinets that contain only 11kV switchgear
Totals	**11,665**	

7.3.3 Asset health

7.3.3.1 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 expect to 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. The age profiles are shown in Figures 7.3.1 and 7.3.2.

Steel kiosks in the eastern suburbs nearer the sea are more prone to corrosion and we expect to replace these kiosks much sooner than those in the remainder of our network.

Figure 7.3.1 Substation buildings age profile by zone sub and distribution sub

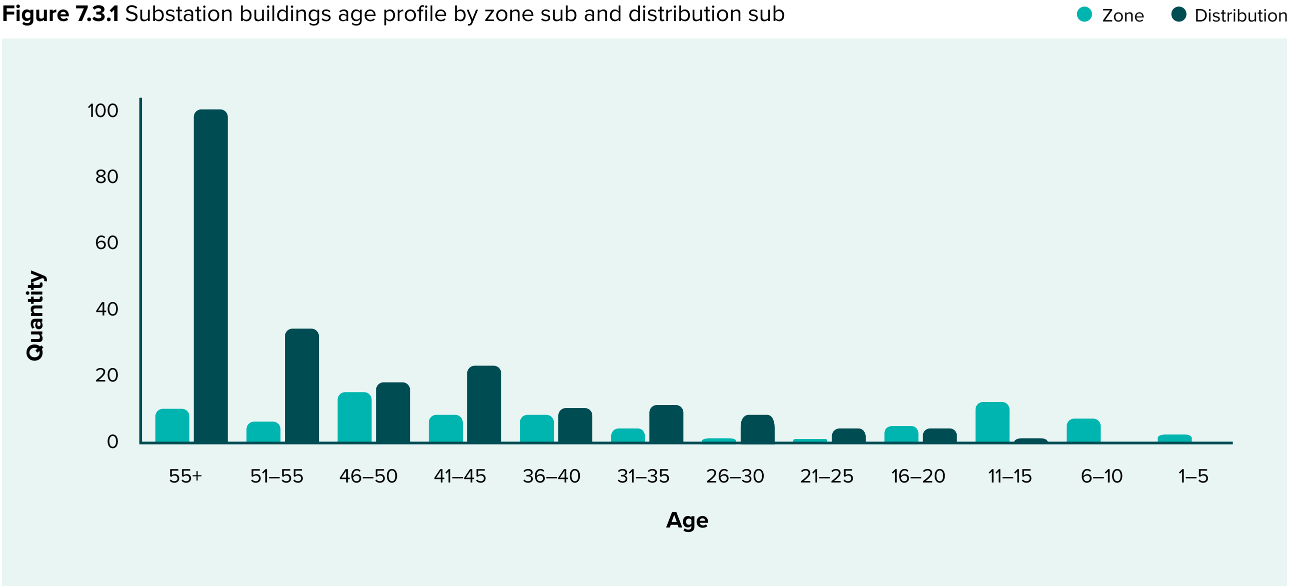
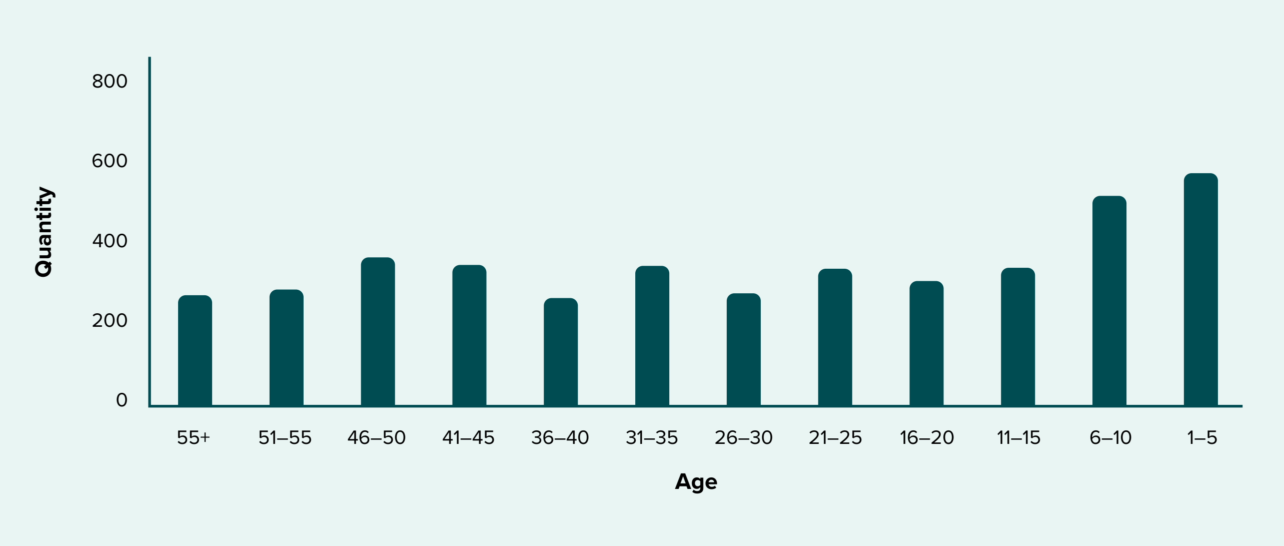


Figure 7.3.2 Kiosk age profile



7.3.3.2 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.

7.3.3.3 Issues and controls

Table 7.3.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.3.3 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	Our 10 year programme to upgrade security and safety has been completed. This involved access (locks and gates/doors), fencing and earthing. All ground-mounted installations in industrial and commercial locations have already been independently surveyed to gauge their susceptibility to damage. To improve public safety we are currently installing double fencing for majority of zone substations; boundary fencing and security fencing
	Vegetation in and around our assets poses an operational safety hazard	We conduct planned and reactive grounds maintenance programmes
	Graffiti 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 (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

7.3.4 Maintenance plan

The substation monitoring and inspection programmes are listed in Table 7.3.4. Our forecast operational expenditure, Table 7.3.5, is in the Commerce Commission categories.

Table 7.3.4 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 as required We maintain and repaint our kiosks as required with more focus to deter rust on the coastal areas	6 months 2 years 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. Over the past few years we have begun to 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

Table 7.3.5 Network property operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	-	-	-	-	-	-	-	-	-	-	**-**
Routine and corrective maintenance and inspections	1,560	1,560	1,560	1,560	1,710	1,710	1,710	1,710	1,710	1,710	**16,500**
Asset replacement and renewal	95	95	95	95	95	95	95	95	95	95	**950**
Total	**1,655**	**1,655**	**1,655**	**1,655**	**1,805**	**1,805**	**1,805**	**1,805**	**1,805**	**1,805**	**17,450**

7.3.5 Replacement plan

The forecast capital expenditure in Table 7.3.6 in Commerce Commission categories covers the following:

- Ongoing replacement of our substation ancillary equipment such as battery banks and battery chargers
- Our replacement programme to address safety and seismic risk of some older pole substation sites by upgrading the substation design to current standards

In addition, we are planning to do the following:

- Upgrade security fencing
- Targeted replacement of steel kiosks located near the coast due to rust

Table 7.3.6 Network property replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Zone substations	50	50	50	50	50	50	50	50	50	50	**500**
Distribution substations and transformers	-	-	-	-	-	-	-	-	-	-	**-**
Other network assets	280	210	180	180	180	180	180	180	180	180	**1,930**
Total	**330**	**260**	**230**	**230**	**230**	**230**	**230**	**230**	**230**	**230**	**2,430**

7.3.5.1 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 7.3.7.

Table 7.3.7 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 95% of our 66kV poles are less than 20 years old and are well within their life expectancy.

7.4 Overhead lines – subtransmission

7.4.1 Summary

Our subtransmission network consists of more than 510 kilometers of lines spanning over 396 towers and 5,837 poles. Subtransmission lines are the backbone of our service to customers. Any failure of our subtransmission network has the potential to severely affect our safety and performance objectives, and disrupt our customer's lives.

The overall condition of Orion's subtransmission lines is good and to ensure we maintain this going forward, our asset management strategy and practices for tower fleet are currently under review.

7.4.2 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 6.

Our subtransmission overhead asset has three distinct components; towers and poles; tower and pole top hardware; and conductors.

Towers and poles

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.

Four types of poles are used: softwood, hardwood, concrete and steel. The nominal service life of softwood and hardwood poles depends on the timber species, preservative treatments and configuration. Wooden poles in areas exposed to harsh environmental conditions have a reduced nominal service life

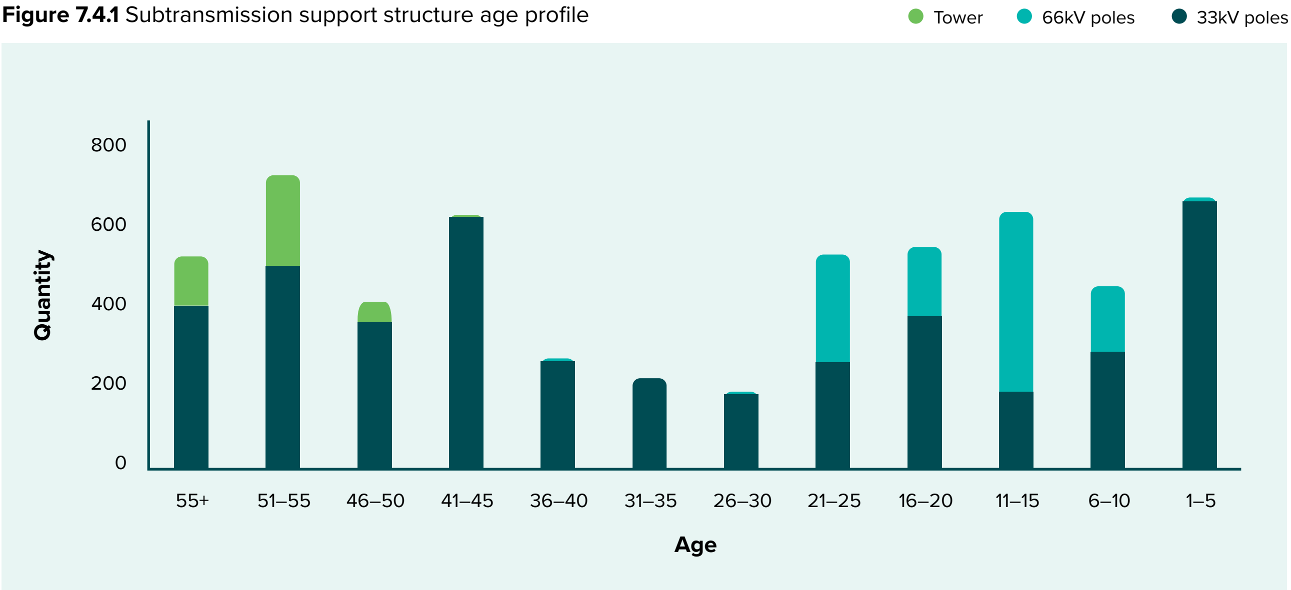
The age profile is shown in Figure 7.4.1. More than 95% of our 66kV poles are less than 20 years old and are well within their life expectancy. We have a large number of 33kV poles. The life expectancy of these poles is 40 to 45 years for wooden poles, and 80 years for concrete poles.

A detailed table of poles by type can be found in Table 7.4.1.

Table 7.4.1 Subtransmission support structure type

Type	66kV	33kV	
	Quantity	Quantity	Total
Hardwood pole	1,000	2,255	3,255
Softwood pole	35	433	468
Concrete pole	24	1,678	1,702
Steel pole	14	2	16
Steel tower	396		396
Total	**1,469**	**4,368**	**5,837**

Figure 7.4.1 Subtransmission support structure age profile



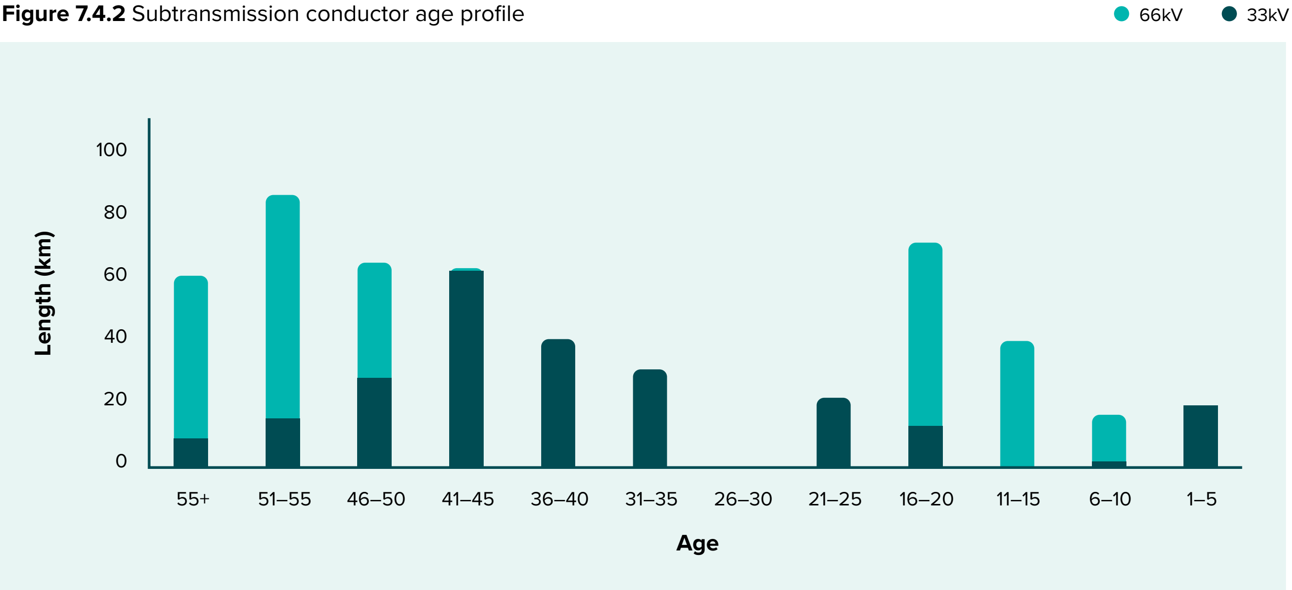
Towers and pole top hardware
Tower hardware is attached directly to the steel lattice structure. It consists of mainly glass disc assemblies in strain and suspension configurations along with some polymer post insulators. Pole top hardware consists of crossarms and insulators. Crossarms are constructed of either hardwood timber or steel. Insulators types are porcelain line post, pin type and porcelain/glass disc strains and composite polymer strains.

Conductors
Conductor types on our 33kV and 66kV overhead lines consist of hard drawn copper (HD) and aluminium conductor steel reinforced (ACSR). Details of conductor type and age profile can be found in Table 7.4.2 and Figure 7.4.2.

Table 7.4.2 Subtransmission conductor type

Type	66kV	33kV	
	Length (km)	Length (km)	Total
ACSR	244	211	455
Copper	15	39	54
Total	259	250	509

Figure 7.4.2 Subtransmission conductor age profile



7.4.3 Asset health

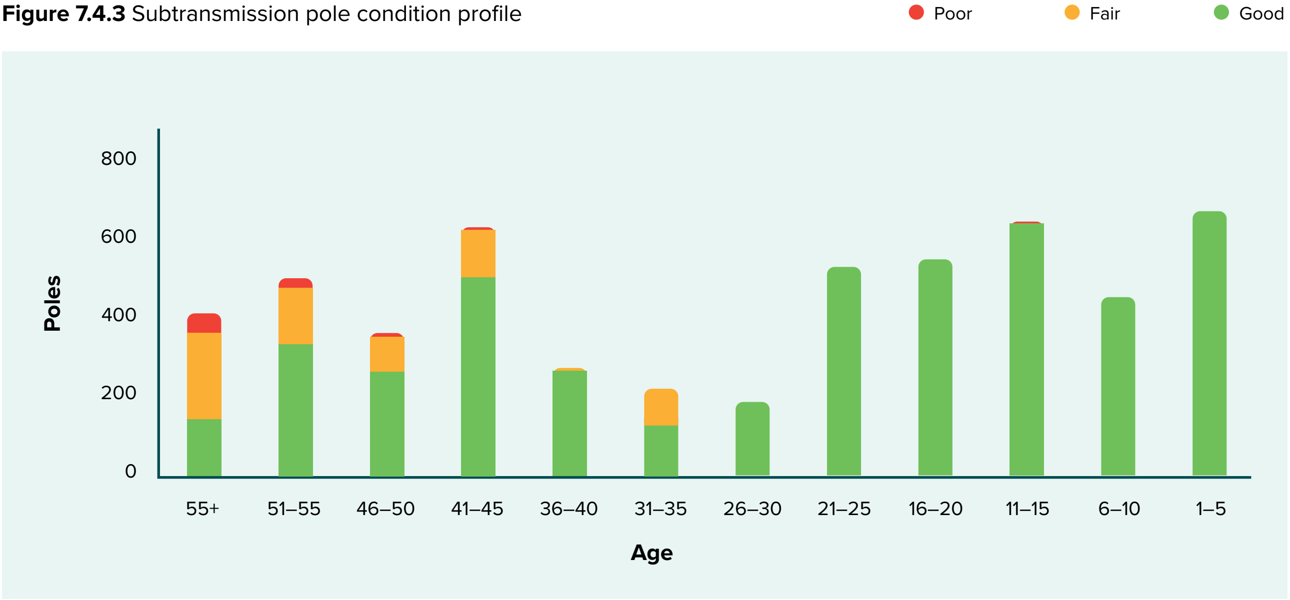
7.4.3.1 Condition

Towers
The overall condition of our steel towers is good. The towers between Addington and Islington came with no additional paint protection which we are addressing with our painting programme. The condition of most tower grillage foundations below ground level is good. A few are in fair condition due to corrosion. We have a foundation refurbishment and concrete encasement programme to address the condition of these towers.

Poles
As shown in Figure 7.4.3 the overall condition of the subtransmission poles is good. Some 33kV mainly wood poles are in fair condition and are showing signs of age-related deterioration. These are being prioritised for replacement

> **The overall condition of our steel towers is good.**

Figure 7.4.3 Subtransmission pole condition profile

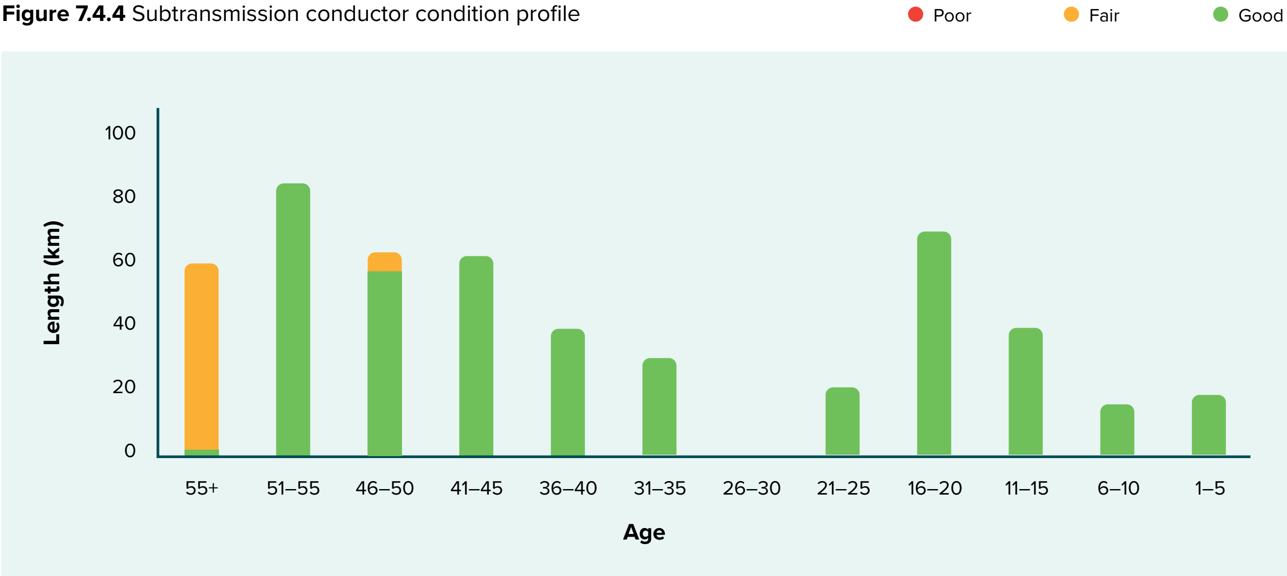


Conductor

The conductors on the overhead subtransmission network are generally performing well (Figure 7.4.4). The copper conductor on some 33kV lines is older and showing some signs of wear and is being monitored accordingly. 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 later in the 10 year plan. We will retest these conductors in the interim to assess the rate of deterioration and better determine end of life.

Figure 7.4.4 Subtransmission conductor condition profile

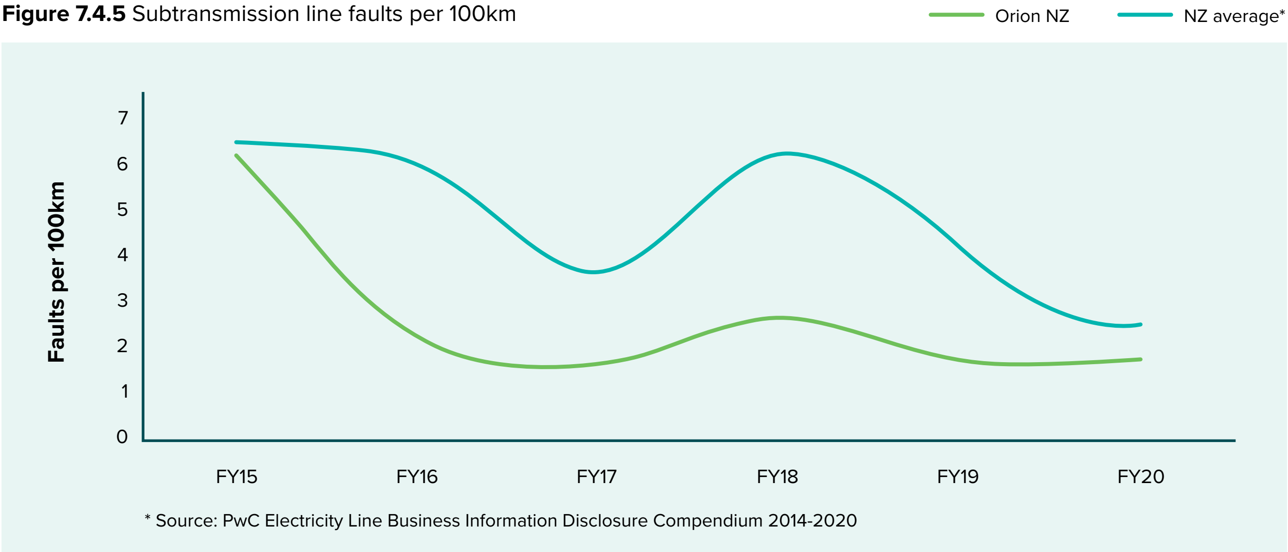


7.4.3.2 Reliability

Our overhead subtransmission network has withstood several snow/wind storms and has performed very well. Using information disclosure data, Figure 7.4.5 shows our subtransmission lines failure rate has been lower than the industry average for the last five years.

Our subtransmission lines failure rate has been lower than the industry average for the last five years.

Figure 7.4.5 Subtransmission line faults per 100km



* Source: PwC Electricity Line Business Information Disclosure Compendium 2014-2020

7.4.3.3 Issues and controls

Table 7.4.3 lists the common causes of overhead line failure and the controls implemented to reduce the likelihood of these failures.

Table 7.4.3 Subtransmission overhead line failure controls

Common failure cause	Known issues	Control measures
Material deterioration	**Pole / tower –** reliability and safety can be impacted by pole or tower failure caused by material deterioration	Robust line design standards exceed the current standards (AS/NZS7000-2016) Conduct inspection programmes, tower maintenance programme and pole replacement programme
Third party interference	**Pole –** third party civil works has the potential to undermine pole foundations	Close Approach consent process is in place to control third party work near poles and measures in place for temporary pole stabilisation
Environmental conditions	**Pole top hardware –** windy conditions leads to binders fatiguing and insulators loosening and failing over time which could impact reliability and safety of the public. Insulators on wooden crossarms can loosen due to shrinkage or rot **Conductor –** snow and ice loads can cause excessive sagging. Sagging lines can clash in high winds leading to conductor damage	Conduct an inspection programme (including corona camera inspection), re-tightening and replacement programme. Sagging or damaged conductor is repaired or replaced as part of these programmes
	Vegetation – trees in contact with lines can cause damage to the conductor and can put public safety at risk. These events also cause interruptions to the network which impacts our SAIDI and SAIFI	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

7.4.4 Maintenance plan

Our maintenance activities as listed in Table 7.4.4, are driven by a combination of time-based inspections, maintenance and reliability centred maintenance.

Table 7.4.4 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	Our obligation is to keep the network safe. We follow the annual tree management programme to remove vegetation when it is required. We also introduced a new programme to address vegetation issues in identified areas Our vegetation trimming programme only allows us to cut trees inside specific zones that are stipulated in the regulations – most vegetation faults happen outside these zones and are out of Orion's control. We also notify tree owners if their trees might become a hazard We will continue to be proactive and carry out the HV tree management programme, work with and educate land owners on the importance of vegetation management around the network and identify and remove vegetation that is at risk of impacting on the network both inside and outside the Notice Zone	2 years
Retightening / refurbishment programme	Includes retightening of components, replacement of problematic assets	Initially at 12 – 18 months from new (retighten), then at 20 years (retighten) and 40 years (refurbishment)
Tower painting	We monitor tower steel condition during the condition assessment programme, 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	Corona inspection and thermal imaging picks up cracked insulators or damaged conductor strands. Visual and lifting inspections provides condition assessment of the tower steel, bolts, attachment points, insulators, hardware and conductors	2 years for corona inspection/thermal imaging 10 years for visual and lifting inspection

A breakdown of subtransmission overhead opex in the Commerce Commission categories is shown in Table 7.4.5. The annual operational expenditure forecast is expected to maintain our current good performance for this asset class.

Table 7.4.5 Subtransmission overhead operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	155	155	155	155	155	155	155	155	155	155	**1,550**
Routine and corrective maintenance and inspections	580	1,655	1,525	1,620	1,610	1,930	1,875	1,925	1,910	1,860	**16,490**
Asset replacement and renewal	250	0	0	0	250	250	250	250	250	250	**1,750**
Total	**985**	**1,810**	**1,680**	**1,775**	**2,015**	**2,335**	**2,280**	**2,330**	**2,315**	**2,265**	**19,790**

7.4.5 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 visual 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 does not prevent material deterioration in condition. 'Targeted intervention', 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 7.4.7.

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.

7.4 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 EEA released an asset criticality guide which provides industry-led guidance on how to determine an assets criticality and descriptions and grades of risk. 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 7.4.6 Subtransmission pole risk matrix

Current

Asset criticality index

Asset health index	C4	C3	C2	C1	Total
H1	0	1	16	0	17
H2	0	0	70	0	70
H3	0	67	562	0	629
H4	0	267	740	0	1,007
H5	0	612	3,106	0	3,718
Total	0	947	4,494	0	5,441

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 at Y10

Asset criticality index

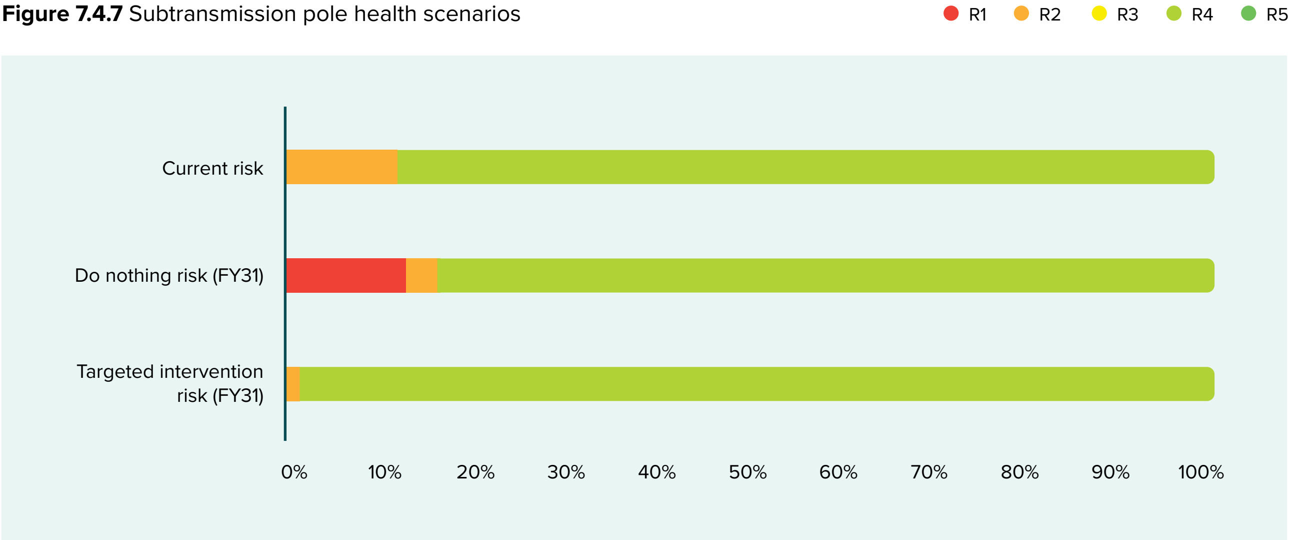
Asset health index	C4	C3	C2	C1	Total
H1	0	60	641	0	701
H2	0	0	0	0	0
H3	0	58	192	0	250
H4	0	501	2,076	0	2,577
H5	0	328	1,585	0	1,913
Total	0	947	4,494	0	5,441

Targeted intervention at Y10

Asset criticality index

Asset health index	C4	C3	C2	C1	Total
H1	0	0	0	0	0
H2	0	0	0	0	0
H3	0	23	89	0	112
H4	0	468	2,068	0	2,536
H5	0	456	2,337	0	2,793
Total	0	947	4,494	0	5,441

Figure 7.4.7 Subtransmission pole health scenarios



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.

Conductor

Our testing has identified that we may need to replace the conductor on our Bromley to Heathcote line in FY27. In the meantime, we will retest the conductor in FY22 to monitor deterioration.

Further out in FY29 we also have a placeholder replacement budget for some conductors between the Islington and Heathcote.

A breakdown of subtransmission overhead capex in the Commerce Commission categories is shown in Table 7.4.6. The annual capital expenditure forecast is expected to maintain our current good performance for this asset class.

Table 7.4.6 Subtransmission replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Overhead lines – Subtransmission	820	1,260	990	1,025	1,080	3,480	980	3480	980	980	**15,075**
Total	**820**	**1,260**	**990**	**1,025**	**1,080**	**3,480**	**980**	**3480**	**980**	**980**	**15,075**

7.4.5.1 Disposal

All poles are disposed of by our service providers in a manner appropriate to the pole type. Where possible they may be recycled, sold as scrap, on-sold for non-commercial purposes or dispatched to waste management landfill. Metal materials are disposed of through members of the Scrap Metal Recycling Association of New Zealand (SMRANZ).

7.4.6 Innovation

We have adopted a non-destructive x-ray testing technology which enables us to better determine conductor condition and optimal replacement timing of our subtransmission conductor. We have trialed the use of a resistance drill on our timber poles to help identify internal decay. Results have been positive, and the drill is used when deemed necessary by Orion engineers. We are now using Unmanned Aerial Vehicles (UAVs) to assist us to maintain and inspect our network. UAVs provides us with economic savings and improved inspections.

Our 11kV distribution overhead system has 3,156km of lines servicing central Canterbury, Banks Peninsula and outer areas of Christchurch city.

7.5 Overhead lines – distribution 11kV

7.5.1 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 minimise pole failures, but also to maintain overall reliability and asset condition.

7.5.2 Asset description

Our 11kV distribution overhead system is 3,156km of lines servicing the rural area of central Canterbury, Banks Peninsula and outer areas of Christchurch city. These lines are supported by 47,784 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 three types of poles:

- **Timber –** comes in hardwood and softwood. Hardwood has superior strength over softwood poles due to its dense fibre characteristics
- **Concrete –** pre-stressed concrete poles which have superior tensile strength compared to precast concrete. We no longer install precast poles on our network
- **Steel pole and piles –** we have four steel monopoles specifically designed to suit their location and span length. We have installed concrete pile structures to support these poles

Today, we predominantly install timber poles. Table 7.5.1 shows the pole types and quantities installed on our network.

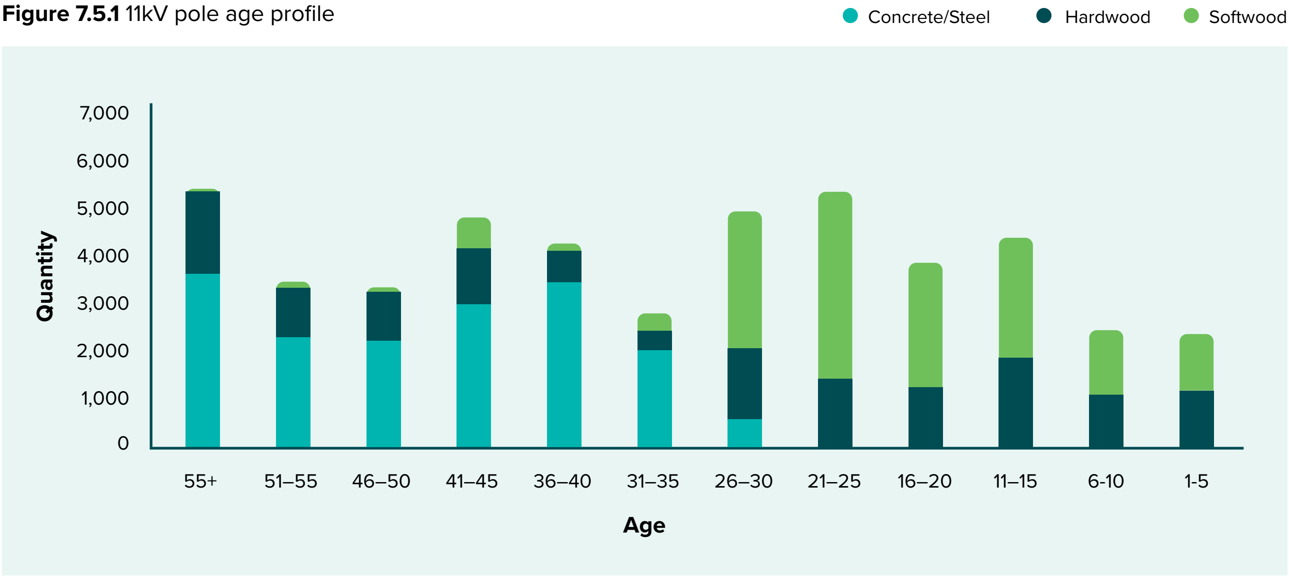
Table 7.5.1 11kV pole quantities by type

Pole type	Quantity
Timber (Hardwood)	14,385
Timber (Softwood)	15,944
Concrete	17,407
Steel pole and piles	48
Total	**47,784**

7.5 Overhead lines – distribution 11kV continued

The Figure 7.5.1 age profile shows a transition in the 1990s from concrete pole to timber pole. This change was made based on a combination of lifecycle economics and engineering considerations. It also shows that the majority of older poles are concrete.

Figure 7.5.1 11kV pole age profile



Pole top hardware

Pole top hardware are the various hardware components used to support overhead conductors 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, glass and polymer insulators installed on our network. We do not have complete records of the ages of these components.

Conductor

A variety of conductor types is used for the 11kV overhead network. Which conductor type is used is influenced by economic considerations, the asset location, environmental and performance factors. The conductor types are listed in Table 7.5.2. They are:

- **Copper –** hard drawn stranded copper conductor, which is no longer installed on the 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

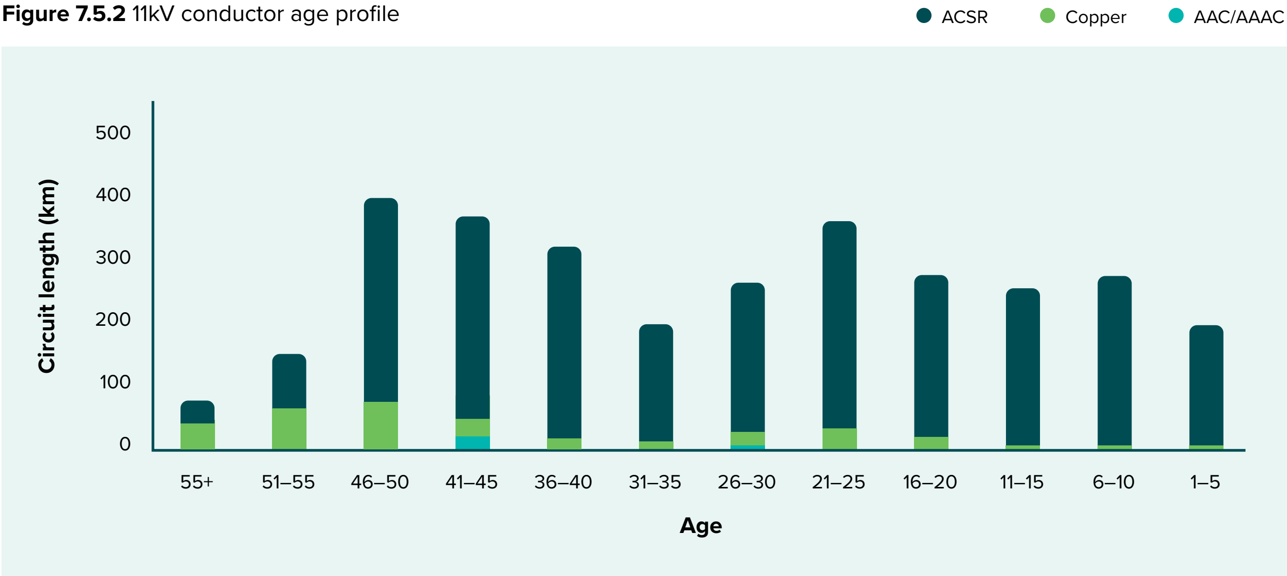
Table 7.5.2 11kV conductor quantities by type

Conductor type	Length (km)
Copper (Cu)	295
Aluminium (ACSR)	2,798
Other aluminium (AAC & AAAC)	63
Total	**3,156**

7.5 Overhead lines – distribution 11kV continued

The age profile in Figure 7.5.2 shows that our conductor population is predominantly ACSR, with hard drawn copper the second most prevalent conductor type.

Figure 7.5.2 11kV conductor age profile



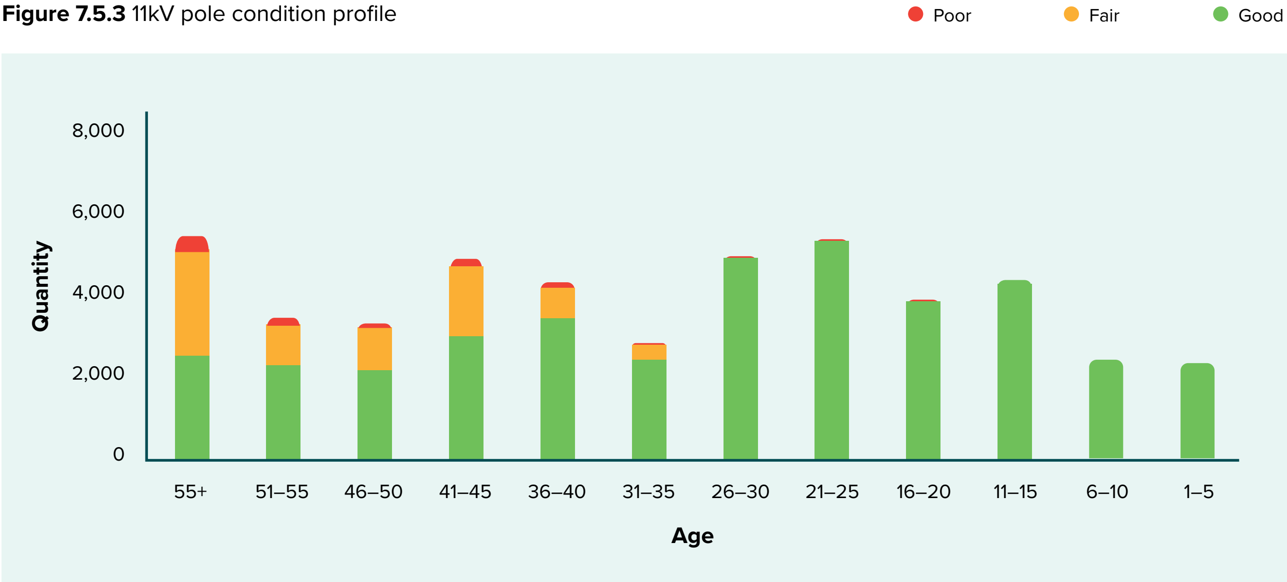
7.5.3 Asset Health

7.5.3.1 Condition

Poles

The condition of the 11kV network has been modelled using CBRM. Figure 7.5.3 shows the current age and condition profile for our overhead 11kV poles. Our poles are predominantly in good condition.

Figure 7.5.3 11kV pole condition profile



Conductor

With the wide range of conductor types and ages there have been a number of poorer performing conductor types. A replacement programme has been under way for several years targeting 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.

7.5.3.2 Reliability

Figure 7.5.4 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, vegetation and lightning strike causes.

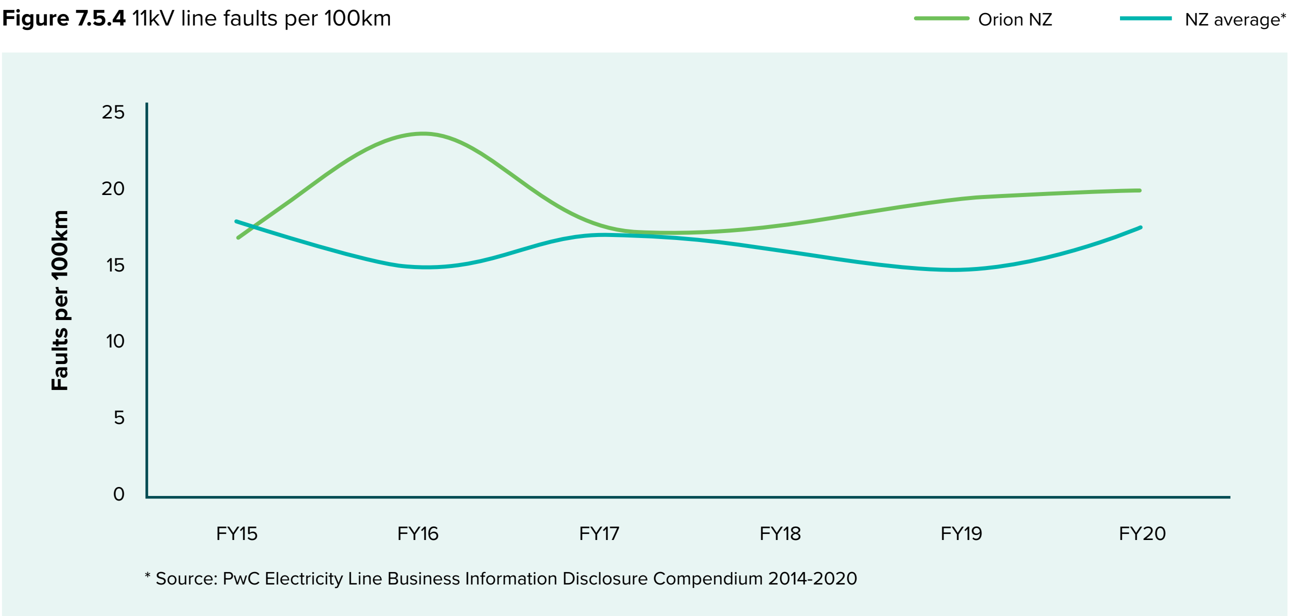
A contributing factor might be warmer weather conditions which caused a mega mast year of exceptionally high levels of plant seeds, stimulating higher breeding rates of wildlife such as possums which climb onto power lines and cause outages. These conditions are also favourable to faster growth rates for vegetation and increased lightning strikes in spring and summer. Over the last two years we have seen a significant increase in lightning strikes particularly in spring and summer with warmer temperatures. These happen predominantly in the rural and Banks Peninsula areas and are sporadic in nature.

We have seen a significant increase of possums coming into contact with our overhead lines over the last four years and we have partnered with the Department of Conservation to help eradicate possums in our most affected areas in Banks Peninsula. Although we have regular vegetation cuts on our network some areas appear to be growing faster than these cutting rounds. We have initiated a project to target areas with vegetation issues.

It is possible the warmer weather is a result of climate change, however more data and further investigation need to be done to determine a strong correlation. We will also review our annual target to adjust it to suit our operating environment.

While the number of faults is increasing, our reliability with regards to SAIDI and SAIFI is improving. This is likely the result of the use of remote line switches on our network that enable us to switch and restore the network faster in response to faults.

Figure 7.5.4 11kV line faults per 100km

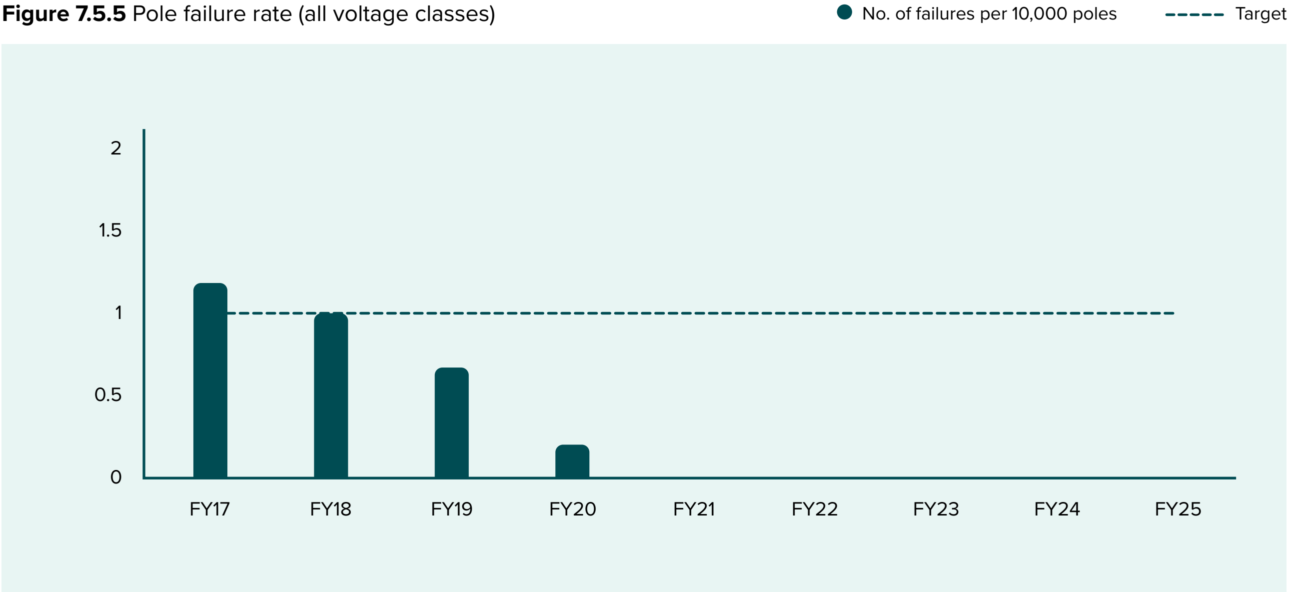


* Source: PwC Electricity Line Business Information Disclosure Compendium 2014-2020

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, four years of comparable data has been reviewed under this benchmark with Figure 7.5.5 showing that we met the asset class objective for the last three years.

Figure 7.5.5 Pole failure rate (all voltage classes)



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[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.

7.5 Overhead lines – distribution 11kV continued

Table 7.5.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.5.3 11kV overhead line failure controls

Common failure cause	Known issues	Control measures
Material degradation	**Pole –** loss of strength over time **Pole top hardware –** binders fatigue and insulators fail over time which can have an impact on reliability and public safety **Conductor –** degrade over time, fretting, corrosion, loss of cross–sectional area	Robust design standards exceed AS/NZS7000–2016 Pole inspection programme and replacement programme Conductor visual inspection
Environmental conditions	**Pole –** poor ground conditions can contribute to wooden pole structure decay **Pole top hardware –** intense vibrations from earthquakes and weather can cause stress on insulators **Conductor –** snow and ice loads on conductor can cause excessive sagging. Lines can clash in high winds leading to conductor damage causing outages	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)
	Conductor – trees in contact with conductors can damage the conductor and heighten the risk of electrocution to anyone coming into contact with them or environmental impacts	Tree regulations Vegetation control work programme Tree cut notices are sent to tree owners Media advertising campaign

7.5.4 Maintenance plan

Regular inspections are carried out to ensure the safe and reliable operation of our assets. This supports our asset class objectives to maintain our overhead network performance in balance with risk and cost to meet customer expectations.

Our maintenance activities, as listed in Table 7.5.4, are driven by a combination of time based inspections, and reliability centred maintenance.

Table 7.5.4 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 Table 7.4.4 for more information	Two years
Retightening / refurbishment programme	Includes retightening of components, replacement of problematic assets 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 (retighten/ refurbishment)

An annual forecast of 11kV overhead operational expenditure in the Commerce Commission categories is shown in Table 7.5.5.

Table 7.5.5 11kV overhead operational expenditure (real) $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	2,425	2,425	2,425	2,425	2,425	2,425	2,425	2,425	2,425	2,425	**24,250**
Vegetation management	3,620	3,400	3,500	3,600	3,100	3,100	3,100	3,100	3,100	3,100	**32,720**
Routine and corrective maintenance and inspections	670	715	1,635	1,635	1,615	815	825	770	1,570	1,570	**11,820**
Asset replacement and renewal	860	815	695	695	615	615	605	660	660	660	**6,880**
Total	**7,575**	**7,355**	**8,255**	**8,355**	**7,755**	**6,955**	**6,955**	**6,955**	**7,755**	**7,755**	**75,670**

7.5.5 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 as shown in Figure 7.5.6 and Figure 7.5.7.

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 7.5.6 11kV pole risk matrix

Current

Asset criticality index (columns); Asset health index (rows)

	C4	C3	C2	C1	Total
H1	9	87	10	0	106
H2	39	447	43	0	529
H3	594	5,879	500	0	6,973
H4	271	13,059	523	0	13,853
H5	736	23,938	1,649	0	26,323
Total	1649	43410	2725	0	47,784

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 at Y10

Asset criticality index (columns); Asset health index (rows)

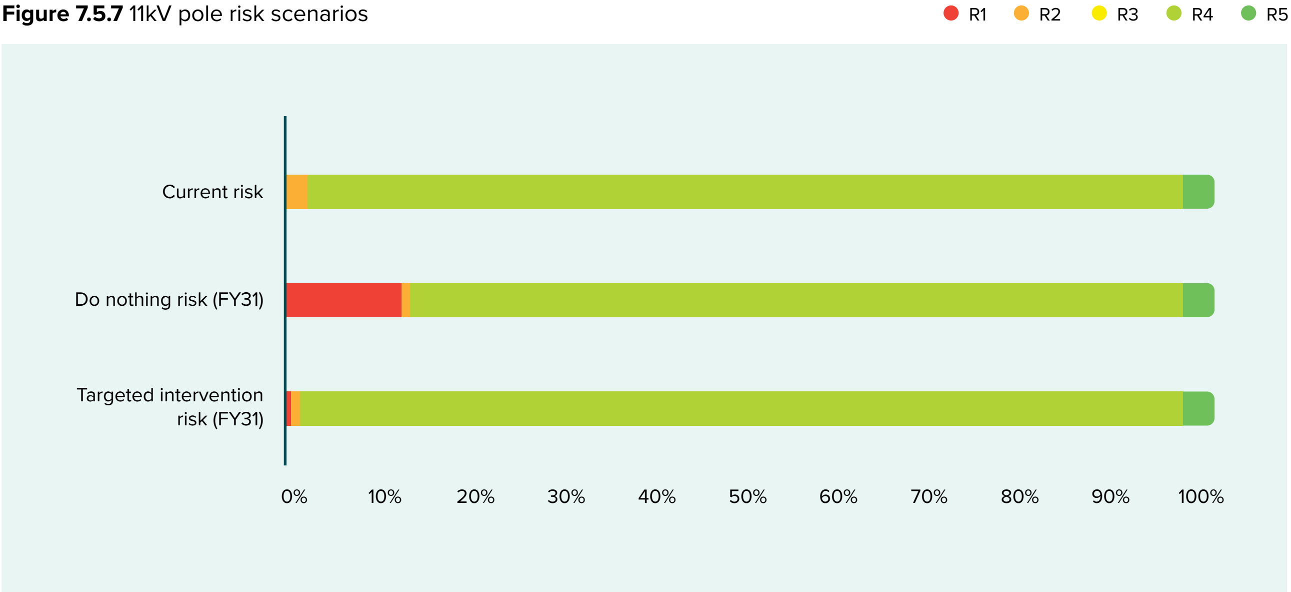
	C4	C3	C2	C1	Total
H1	620	5,433	522	0	6,575
H2	15	167	3	0	185
H3	137	7,133	246	0	7,516
H4	523	20,316	1,217	0	22,056
H5	354	10,361	737	0	11,452
Total	1649	43,410	2,725	0	47,784

Targeted intervention at Y10

Asset criticality index (columns); Asset health index (rows)

	C4	C3	C2	C1	Total
H1	8	276	6	0	290
H2	15	164	3	0	182
H3	130	7,009	246	0	7,385
H4	522	20,285	1,216	0	22,023
H5	974	15,676	1,254	0	17,904
Total	1649	43410	2,725	0	47,784

Figure 7.5.7 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 condition profile in FY31 shows some poles as red or "high" risk the overall risk profile remains largely the same. This also aligns with our health and safety focus.

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 replacement of our mainly wooden poles, as shown in Figure 7.5.8.

Figure 7.5.8 11kV pole replacement plan

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 7.5.6.

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 focussing 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 7.5.6.

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.

Table 7.5.6 11kV overhead replacement capital expenditure (real) $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Distribution & LV Lines	5,700	6,371	8,371	8,881	10,811	11,321	11,944	10,720	10,210	10,210	**94,539**
Distribution switchgear	525	525	525	525	525	525	300	300	300	300	**4,350**
Other reliability, safety and environment	-	-	-	-	-	2,000	2,000	2,000	2,000	2,000	**10,000**
Total	**6,225**	**6,896**	**8,896**	**9,406**	**11,336**	**13,846**	**14,244**	**13,020**	**12,510**	**12,510**	**108,889**

7.5.5.1 Disposal

All poles are disposed of by our service providers in a manner appropriate to the pole type. Where possible they may be recycled, sold as scrap, on-sold for non-commercial purposes or dispatched to waste management landfill. Metal materials are disposed of through members of the Scrap Metal Recycling Association of New Zealand (SMRANZ).

7.5.6 Innovation

We worked with local authorities, Christchurch City Council, Selwyn District Council and ECan to improve our operational efficiency and reduce cost by gaining global consents for the repetitive activity of trenching and installing poles across our network. We are currently working on obtaining a similar consent from Selwyn District Council.

This innovation in improving our efficiency delivers on our asset management strategy focus on operational excellence.

Our customers benefit from our minimisation of compliance costs while we continue to meet resource consenting requirements.

Air Break Isolators are now replaced with line switches which have the capability to utilise remote operation. The benefits are that they minimise potential harm during operation and have the potential to minimise the size and duration of outages in certain situations.

We are beginning to trial Fusesavers on our 11kV overhead network. These act as a single phase circuit breaker and recloser. The benefit of the reclose function should greatly increase reliability.

We currently have a project underway to automatically enable/disable our auto-reclosers by network segment in response to localised weather data during fire seasons, and by doing so we can reduce fire risk and also reduce supply interruptions.

Our low voltage 400V distribution overhead system is 2,362km of lines mainly within Region A, delivering power from the street to customer's premises.

7.6 Overhead lines – distribution 400V

7.6.1 Summary

Our low voltage 400V distribution overhead system is 2,362km of lines mainly within Region A, delivering power from the street to customer's premises. The lines are supported by wooden and concrete poles. To counteract our aging pole population and maintain our performance we are increasing the pole replacement rate over the AMP period. We are also improving the quality of our fault data so that we can proactively target areas with vegetation issues.

7.6.2 Asset description

The 400V overhead asset comprises three distinct components; poles, pole top hardware and conductors.

Poles

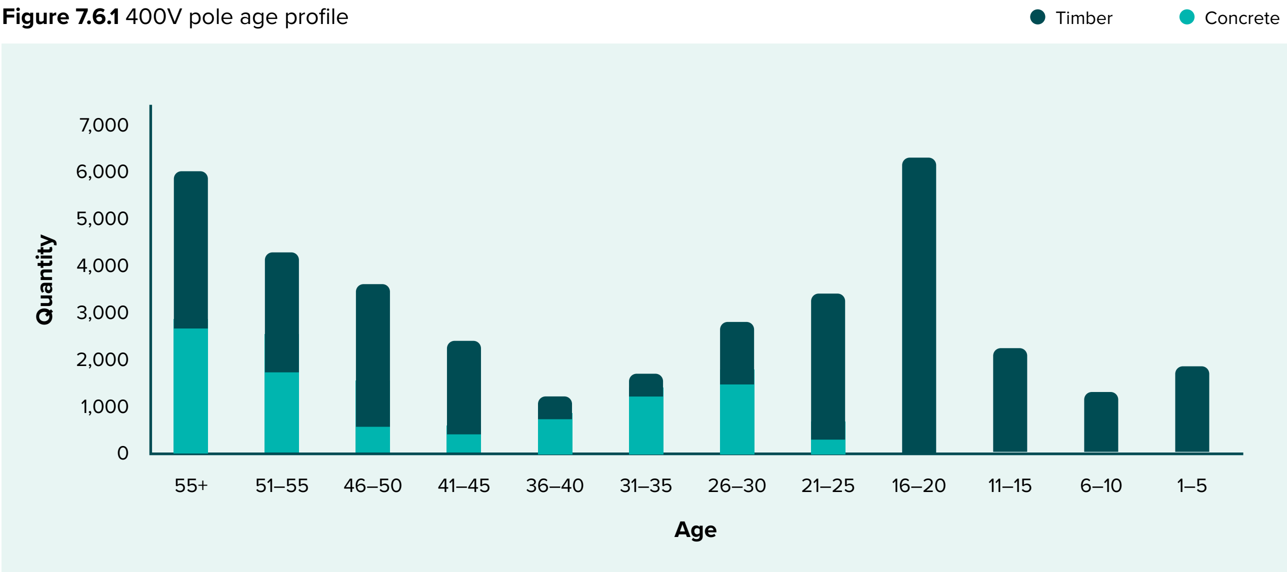
We have three main types of poles: softwood, hardwood and concrete. The current types we install are softwood and hardwood. Many of our older wooden poles have estimated ages as no install date or manufacture date was recorded or available circa pre-2000. The quantities by type are listed in Table 7.6.1.

Table 7.6.1 400V pole quantities by type

Pole type	Quantity
Timber (hardwood)	11,151
Timber (softwood)	14,758
Concrete	9,149
Steel	3
Total	**35,061**

The profile in Figure 7.6.1 shows that the older poles are a mix of wooden 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 between 16-20 years, which required replacement due to the installation of a telecommunications network on our poles.

Figure 7.6.1 400V pole age profile



7.6 Overhead lines – distribution 400V continued

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 typical life of 40 years. We have porcelain insulators installed on our network. We collect pole top hardware data on condition and record age/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 7.6.2.

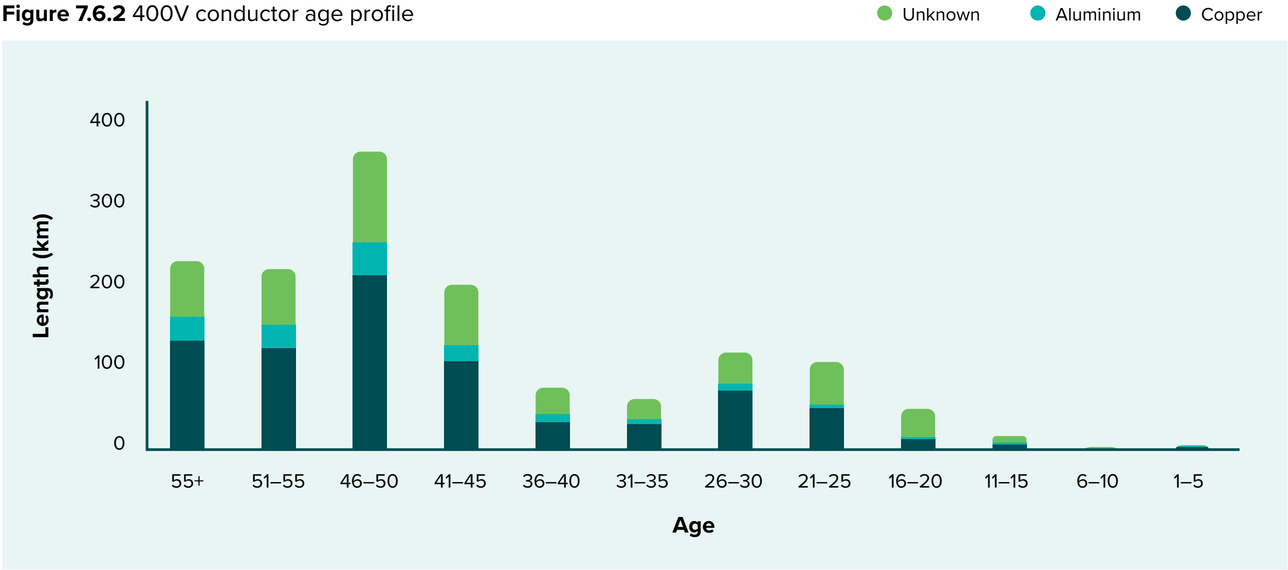
Table 7.6.2 400V conductor quantities by type

Conductor type	Length (km)
Copper (Cu)	795
Aluminium (Al)	149
Unknown	516
Streetlighting (Cu)	902
Total	**2,362***

* Total figure excludes adjustment for road crossings and back section lines.

The age profile in Figure 7.6.2 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 7.6.2 400V conductor age profile



7.6.3 Asset health

7.6.3.1 Condition

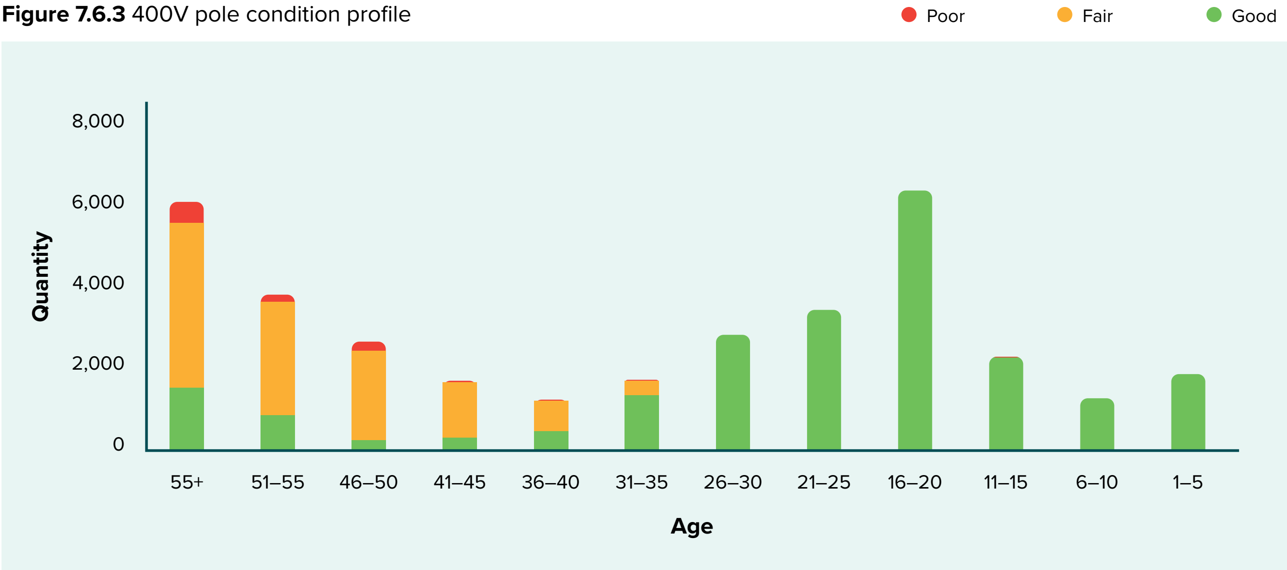
Poles

The condition of the low voltage poles has been modelled using the process of CBRM. Figure 7.6.3 shows the condition profile for our overhead LV poles. It can be seen that the pole population is predominantly in good or fair condition, with a smaller amount in poor condition.

Conductors

The condition of the conductors is generally good. Low voltage conductors are predominantly PVC covered with typically shorter spans and tensions of about 5% of Conductor Breaking Load which extends life expectancy.

Figure 7.6.3 400V pole condition profile



7.6.3.2 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. Faults related to adverse weather have also been trending down over the same period and this is likely to be due to having few major weather events in recent 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 intend to continually improve the distinction between weather and vegetation related faults so that identified areas with vegetation issues can be addressed. Third party related incidents have been slowly trending upwards over the last four years. The majority of these are due to contractor vehicles and excavators coming into contact with overhead lines.

7.6.3.3 Issues and controls

The controls for reducing the likelihood of failure for 400V overhead asset is the same as 11kV overhead assets, see Table 7.5.3.

7.6.4 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 7.6.3.

Faults related to adverse weather have also been trending down over the same period and this is likely to be due to having few major weather events in recent years.

Table 7.6.3 400V overhead operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	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**
Vegetation management	900	900	900	900	900	900	900	900	900	900	**9,000**
Routine and corrective maintenance and inspections	2,720	2,510	1,710	1,710	1,610	2,410	2,410	2,410	1,610	1,610	**20,710**
Total	**4,620**	**4,410**	**3,610**	**3,610**	**3,510**	**4,310**	**4,310**	**4,310**	**3,510**	**3,510**	**39,710**

7.6.5 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 7.6.4 400V pole risk matrix

Current

Asset criticality index / Asset health index

	C4	C3	C2	C1	Total
H1	8	665	1	0	674
H2	0	223	0	0	223
H3	193	10,791	142	0	11,126
H4	20	4,791	44	0	4,855
H5	130	17,694	359	0	18,183
Total	351	34,164	546	0	35,061

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 at Y10

Asset criticality index / Asset health index

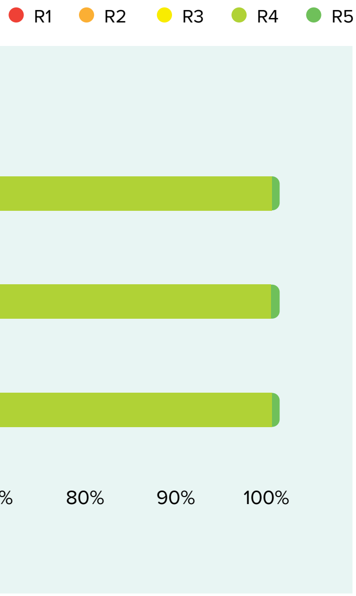
	C4	C3	C2	C1	Total
H1	39	1,812	12	0	1,863
H2	148	8,196	110	0	8,454
H3	17	2,722	30	0	2,769
H4	61	10,996	197	0	11,254
H5	86	10,438	197	0	10,721
Total	351	34,164	546	0	35,061

Targeted intervention at Y10

Asset criticality index / Asset health index

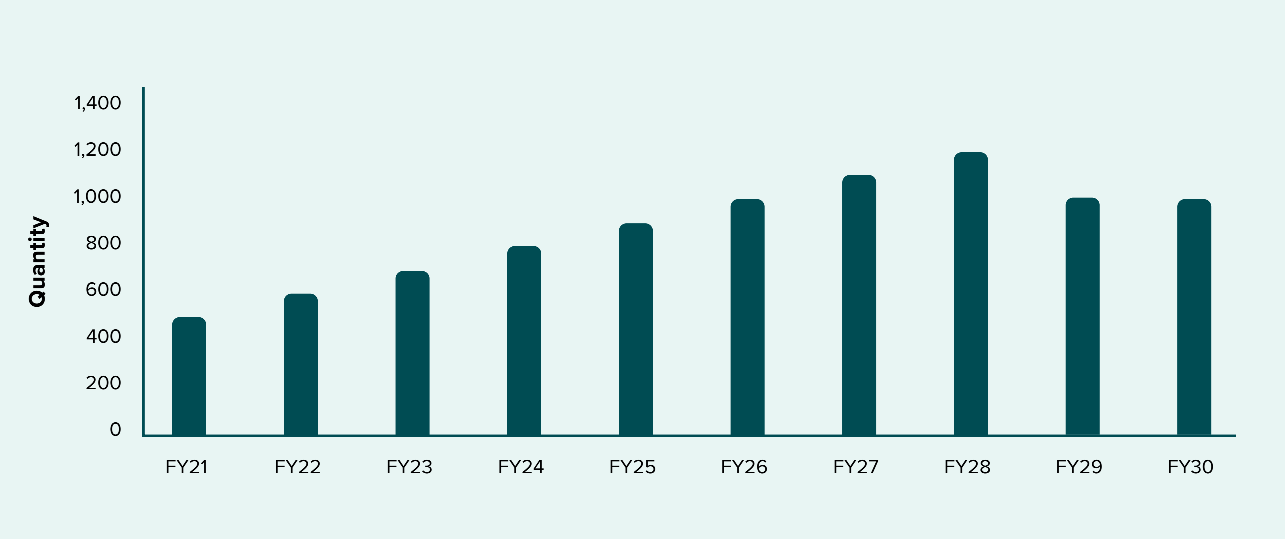
	C4	C3	C2	C1	Total
H1	0	1	0	0	1
H2	7	1182	8	0	1,197
H3	16	2621	28	0	2,665
H4	59	10973	197	0	11,229
H5	269	19387	313	0	19,969
Total	351	34,164	546	0	35,061

Figure 7.6.5 400V pole risk scenarios



As a result we are planning a steady increase in replacement of our mainly wooden poles as shown in Figure 7.6.6. This steady increase is necessary to allow time for our service providers to resource appropriately for the work programme.

Figure 7.6.6 400V pole replacement plan



7.6 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 7.6.4 shows the replacement expenditure in the Commerce Commission categories.

As mentioned in Section 7.5, the pole replacement budget for this asset class has been included in the 11kV overhead capex.

Table 7.6.4 400V overhead replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Distribution & LV Lines	390	390	290	290	290	245	245	245	170	170	**2,725**
Other network assets	200	200	150	150	150	150	150	150	150	150	**1,600**
Other reliability, safety and environment	240	240	-	-	-	-	-	-	-	-	**480**
Total	**830**	**830**	**440**	**440**	**440**	**395**	**395**	**395**	**320**	**320**	**4,805**

7.6.5.1 Disposal

All poles are disposed of by our service providers in a manner appropriate to the pole type. Where possible they may be recycled, sold as scrap, on-sold for non-commercial purposes or dispatched to waste management landfill. Metal materials are disposed of through members of the Scrap Metal Recycling Association of New Zealand (SMRANZ).

Our subtransmission underground cable network delivers electricity from Transpower's GXPs to substations across the region.

7.7 Underground cables – subtransmission

7.7.1 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. The majority of our 66kV and 33kV cables are in good condition. We have identified a resilience risk with our 66kV oil filled cables and a reliability issue with some 33kV XLPE cable joints that we will address over the AMP planning period.

7.7.2 Asset description

Table 7.7.1 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 7.7.1 shows the age cable type quantities for our 33kV and 66kV network.

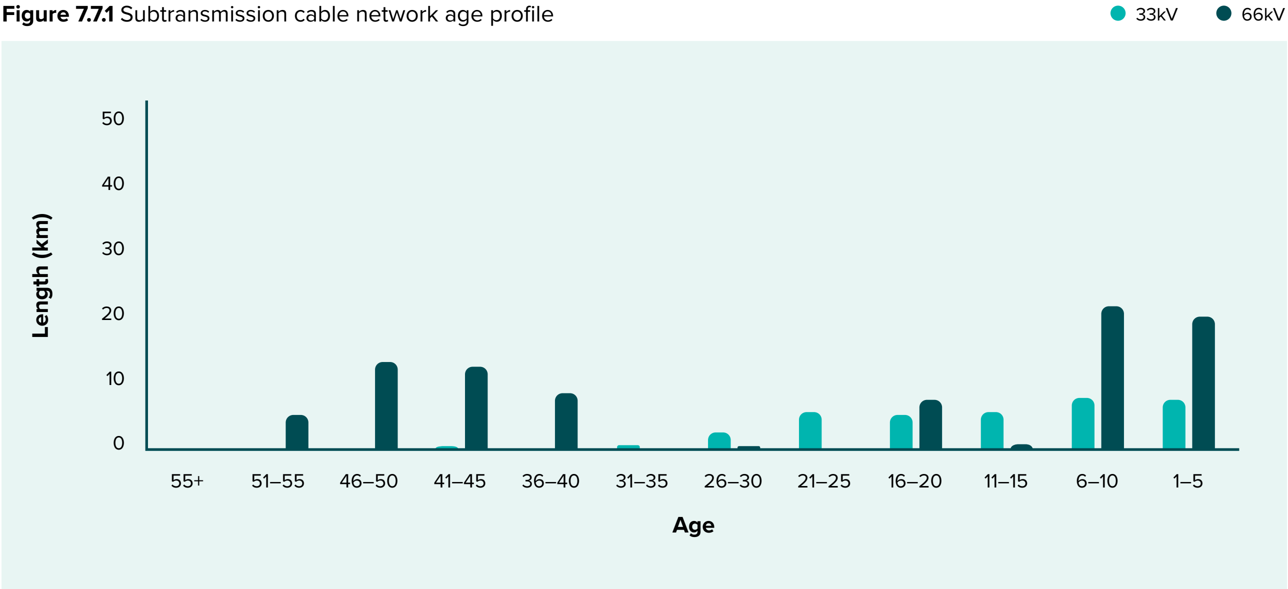
Table 7.7.1 Subtransmission cable length by type

Cable type	Length (km)		
	33kV	66kV	**Total**
PILCA	1	–	**1**
XLPE	36	50	**86**
3 core oil	–	40	**40**
Sub-total	37	90	
Total			**127**

7.7 Underground cables – subtransmission continued

Figure 7.7.1 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 7.7.1 Subtransmission cable network age profile



7.7.3 Asset health

7.7.3.1 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 potential mechanical 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.

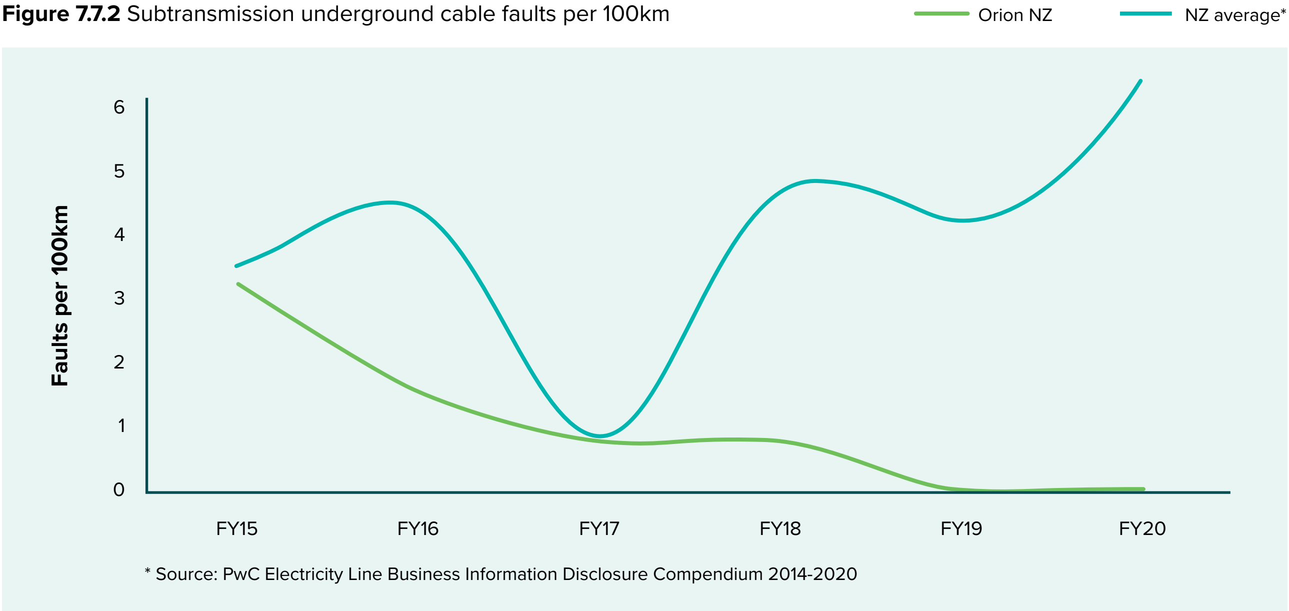
Our 33kV cables are relatively new and are in good condition. However we believe a number of 33kV joints are in poor condition due to a number of recent premature failures of XLPE joints, and we have a joint replacement programme underway.

7.7.3.2 Reliability

Our 66kV cables have been 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 likely to be due to the reduced load on cables that have been identified as vulnerable. We now have a replacement programme targeting any suspect joints. This programme is expected to be completed at the start of FY22.

Figure 7.7.2 Subtransmission underground cable faults per 100km



* Source: PwC Electricity Line Business Information Disclosure Compendium 2014-2020

7.7.3.3 Issues and controls

Subtransmission cable failures are rare, but when they do occur, they can significantly impact our customers through loss of supply. Table 7.7.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.7.2 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 workmanship 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 New 33kV cable is now required to be installed with an orange coloured sheath to allow easier identification Proactive promotion to service providers of cable maps and locating services

7.7.4 Maintenance plan

Our scheduled maintenance plan for subtransmission cables is summarised in Table 7.7.3 and the operational expenditure in the Commerce Commission categories is shown in Table 7.7.4. This includes a new programme for the replacement of some 33kV cable joints to address the cause of some recent premature failures. We will review the future rate of joint replacement in line with the trend in asset performance and joint condition we observe.

Table 7.7.3 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
Cable joint inspection and replacement programme	We have a programme for the replacement of suspect 33kV XLPE cable joints	Ongoing

Table 7.7.4 Subtransmission underground operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	110	110	110	110	110	110	110	110	110	110	**1,100**
Routine and corrective maintenance and inspections	80	30	30	30	30	30	30	30	30	30	**350**
Asset replacement and renewal	450	400	400	-	-	-	-	-	-	-	**1,250**
Total	**640**	**540**	**540**	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**2,700**

7.7.5 Replacement plan

Our 66kV oil filled cables and joints have a medium to high risk of multiple faults occurring when the Alpine Fault ruptures, that is a 30% chance in the next 50 years.

To minimise the risk of failure and to continue investing in the network resilience and provide security and confidence for our community, the replacement of our 40km of oil filled 66kV cables will be integrated into a wider 66kV architecture project.

We have allowed expenditure to carry out concept design for the 66kV cable route over the planning period.

7.7.5.1 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.

Table 7.7.5 Subtransmission underground capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Subtransmission	50	50	50	50	50	50	50	50	50	50	**500**
Total	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**500**

90% of our 2,736km network of 11kV underground cables are in the urban area of Christchurch also known as Region A.

7.8 Underground cables – distribution 11kV

7.8.1 Summary

90% of our network of 11kV underground cables are in the urban area of Christchurch also known as Region A. The overall condition of these cables is good. We proactively monitor, test and maintain our 11kV cables. Based on our current assessment, while failures do occur, from a cost-benefit point of view these are not at a significant level to warrant a scheduled 11kV cable replacement programme.

7.8.2 Asset description

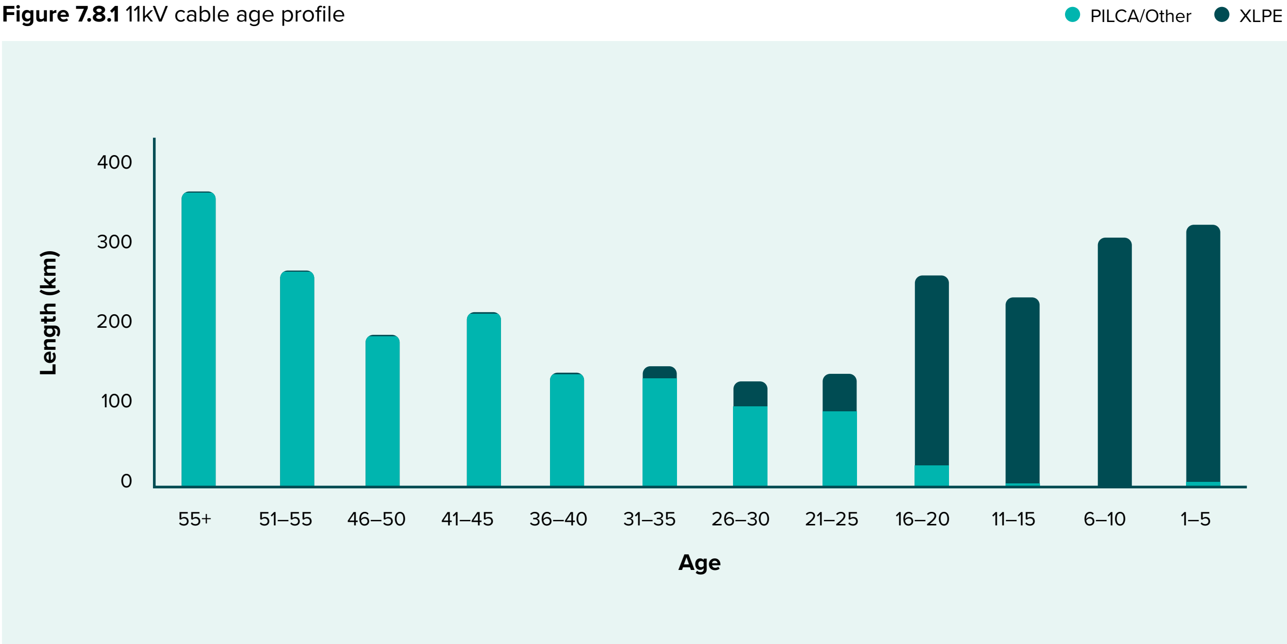
There are two types of 11kV underground cable in our network:

- **PILCA** – paper insulated lead armour cables
- **XLPE** – cross linked polyethylene insulated power cables

Table 7.8.1 11kV cable length by type

Cable type	Length (km)
PILCA	1,531
XLPE	1,190
Others	15
Total	**2,736**

Figure 7.8.1 11kV cable age profile



7.8.3 Asset health

7.8.3.1 Condition

The condition of these cables is 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. This indicates that our cables are in good condition.

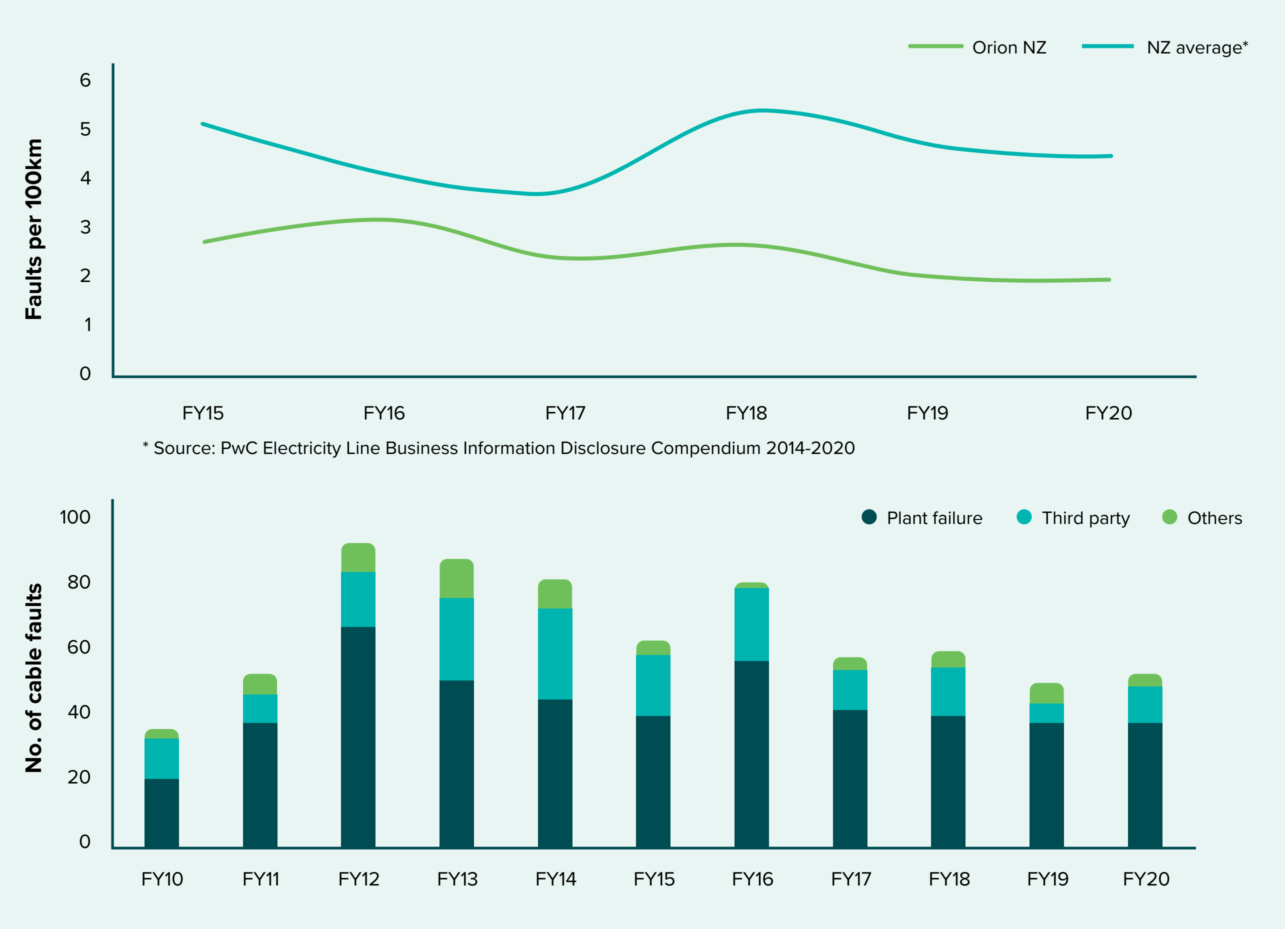
7.8.3.2 Reliability

In FY20, 11kV cable faults contributed to 10% of the total SAIDI and 17% 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 Regenerate Christchurch. In the meantime, we are maintaining this network until its future is decided.

> **We have seen a downward trend in third party cable strikes and other failure modes since 2014.**

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 7.8.2. '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 7.8.2 Number of 11kV underground cable failures and the corresponding SAIDI and SAIFI



* Source: PwC Electricity Line Business Information Disclosure Compendium 2014-2020

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 failure is broken down to 48% joint, 40% run of the cable and 12% 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.

7.8.3.3 Issues and controls

Table 7.8.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.8.2 11kV cable failure control

Common failure cause	Known issues	Control measures
Workmanship	Termination and joint failures can occur due to poor workmanship. 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 New cable sheaths are now orange coloured 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

7.8.4 Maintenance plan

We have programmes to address identified failure modes of cables. These failure modes have been predominately related to the terminations. An inspection and maintenance programme has been implemented. 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 7.8.3.

Table 7.8.3 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 7.8.4.

Table 7.8.4 11kV underground operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	**17,000**
Routine and corrective maintenance and inspections	450	450	450	450	450	450	450	450	450	450	**4,500**
Total	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**21,500**

7.8.5 Replacement plan

Any significant 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 6 – 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 7.8.5.

Table 7.8.5 11kV underground replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Distribution & LV cables	300	300	100	100	100	100	100	100	100	100	**1,400**
Total	**300**	**300**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**1,400**

7.8.5.1 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. 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 3,262km and delivers electricity to street lights and customer’s premises largely in Region A.

7.9 Underground cables – distribution 400V

7.9.1 Summary

Our 400V cable network is 3,262km and delivers electricity to 2,697km of street lights and customer’s premises largely in Region A. We also have around 50,000 distribution cabinets and distribution boxes installed on our 400V cable network. Generally, this cable network, cabinets and boxes are in good condition. We are currently in the process of carrying out a supply fuse relocation programme to increase safety for our customers and the public.

7.9.2 Asset description

The 400V underground asset class comprises two distinct subsets: LV cables and LV enclosures.

LV Cables

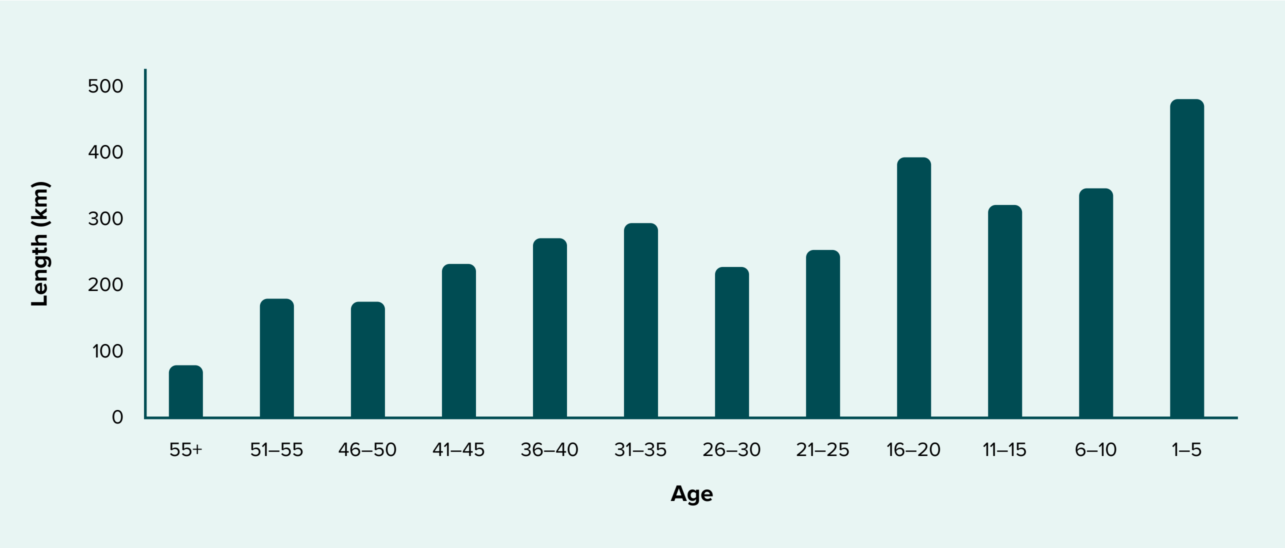
We have two groups of cables: distribution cables and street-lighting cables as shown in Table 7.9.1. They are:

- **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 7.9.1 400V cable and street-lighting networks cable type

Cable type	Length (km)
PVC	847
PILCA	103
XLPE	2,312
Total	**3,262**
Street-lighting cable	2,697

Figure 7.9.1 LV cable age profile



LV Enclosures

We have two groups of enclosures, see Table 7.9.2. They are:

- **Distribution cabinets –** allow the system to be reconfigured – each radial feeder must be capable of supplying or being supplied from the feeder adjacent to it – in the event of component failure or other requirements. 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. All are above ground. The majority are a PVC cover on a steel base frame, although some older types are concrete or steel

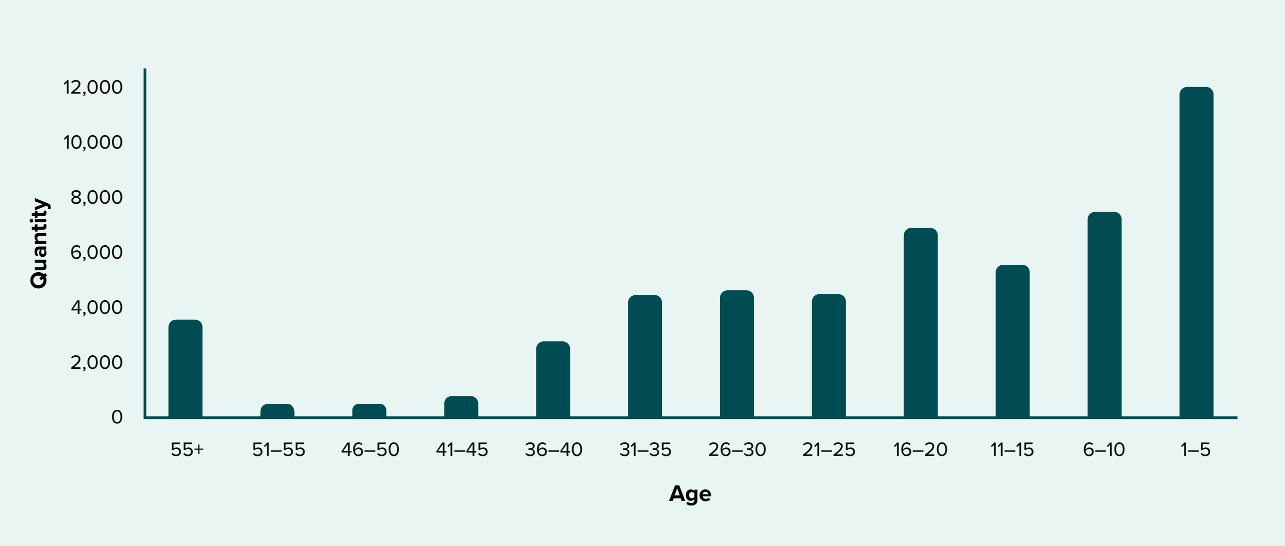
The age profile is shown in Figure 7.9.2.

We inspect our distribution cabinets and boxes every five years, with any defects remedied in a subsequent contract.

Table 7.9.2 Distribution enclosure type

Distribution enclosure type	Quantity
Distribution cabinet	6,507
Distribution box	50,402
Total	**56,909**

Figure 7.9.2 LV enclosures age profile



7.9.3 Asset health

7.9.3.1 Condition

The vast majority of our distribution cabinets and boxes are in good 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. Based on our assessments of expected service life, fleet age and failure analysis we estimate the overall condition of the LV underground cables to be good.

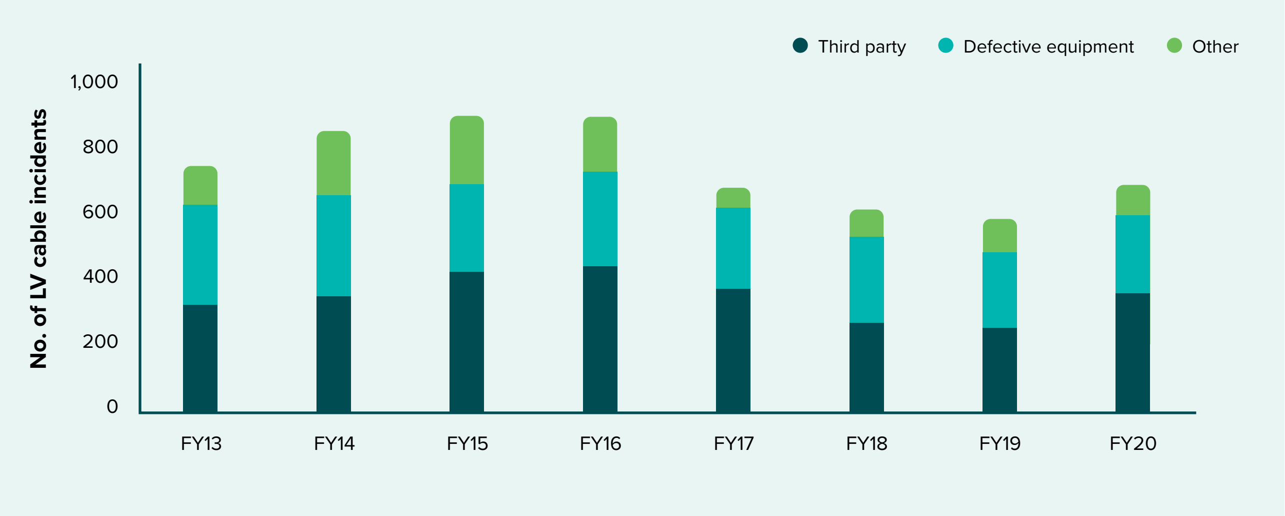
7.9 Underground cables – distribution 400V continued

7.9.3.2 Reliability

We are not required to record SAIDI/SAIFI for our LV networks. However to ensure prudent asset management and good stewardship we collect performance data on our LV system. The number of LV underground call-outs our service providers address under emergency maintenance is shown in Figure 7.9.3. The majority of call-outs relate to third party damage and service or network cable failures.

Overall, our LV cable network performs well. The other faults captured are mostly faults with street lighting which is owned by the Christchurch City Council but which an Orion operator is normally called to attend the site.

Figure 7.9.3 Cause of LV cable incidents



7.9.3.3 Issues and controls

Table 7.9.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.9.3 LV cable network failure controls

Common failure cause	Known issues	Control measures
Material degradation	Quality of workmanship 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 safety advertising in the media

7.9.4 Maintenance plan

Our scheduled maintenance plan is summarised in Table 7.9.4 and the associated expenditure in the Commerce Commission categories is shown in Table 7.9.5.

Table 7.9.4 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	5 years
Distribution enclosures	Visual inspection programme of the above-ground equipment and terminations. Major defects identified and scheduled for rectification	5 years

Table 7.9.5 400V underground operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	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	1,295	1,295	1,295	1,295	1,295	1,295	1,295	1,295	1,295	1,295	**12,950**
Total	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**28,950**

7.9.5 Replacement plan

We have developed a programme to install distribution boxes complete with fusing on the supply. This project is programmed to be complete in 2028. We are also upgrading our existing distribution cabinets to a more secure design. A detailed breakdown of replacement in the Commerce Commission categories is shown in Table 7.9.6.

Table 7.9.6 400V underground replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Distribution and LV cables	415	470	470	470	470	570	570	570	570	570	**5,145**
Other reliability, safety and environment	6,750	6,750	6,750	6,750	6,750	6,750	930	-	-	-	**41,430**
Total	**7,165**	**7,220**	**7,220**	**7,220**	**7,220**	**7,320**	**1,500**	**570**	**570**	**570**	**46,575**

7.9.5.1 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.

Circuit breakers and switchgear contribute to our asset management objectives by providing capability to control, protect and configure the electricity network.

7.10 Circuit breakers and switchgear

7.10.1 Summary

Circuit breakers and switchgear contribute to our asset management objectives by providing capability to control, protect and configure the electricity network. Most of our circuit breakers and switchgear are in good condition overall, and meeting our service level targets. However, there are some older oil-filled breakers and 66kV and 33kV switchgear that have a poor health index.

We also have an ageing 11kV switchgear group that require a steadily rising replacement programme to maintain current health profile and performance.

7.10.2 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 7.10.1 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 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. This has the advantage of improved security and public safety. The newer circuit breakers at a number of our zone substations are an indoor metal-clad vacuum interruption type. We also have a number of oil filled and SF$_6$ units.
11kV	Circuit breaker	These 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.
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.

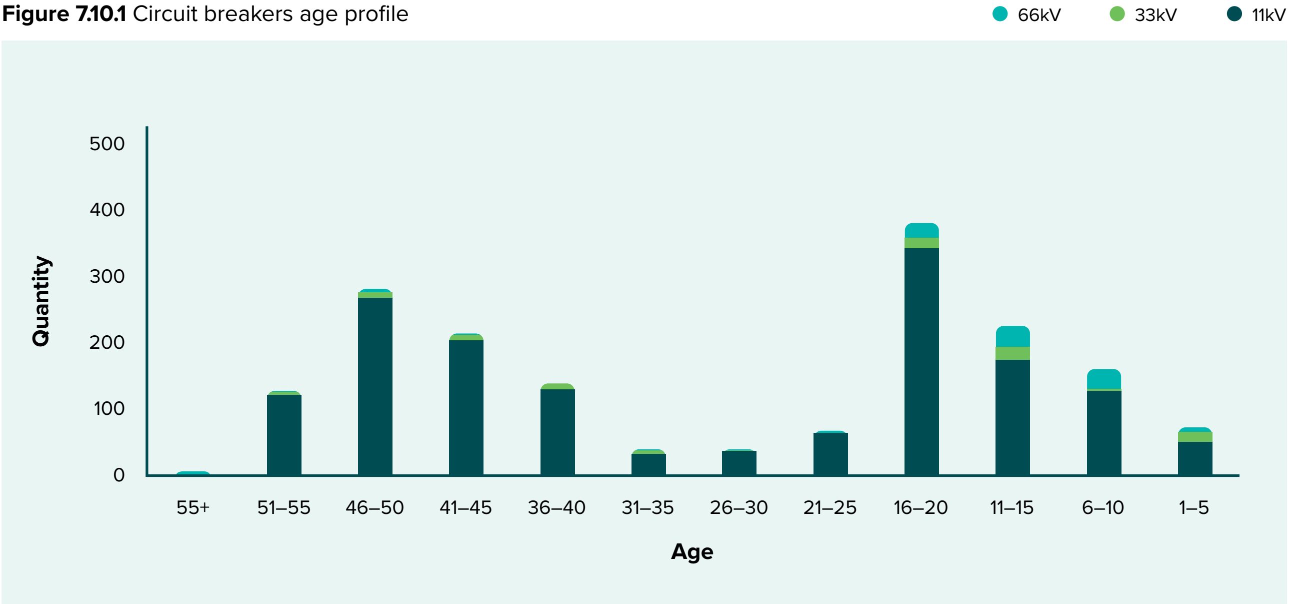
Table 7.10.2 Circuit breaker quantities by type

Voltage	Asset Type	Quantity
66kV	Oil	13
	SF_6	100
33kV	Oil	32
	SF_6	8
	Vacuum	42
11kV	Oil	733
	SF_6	34
	Vacuum	799
	Total	**1,761**

Most of our circuit breakers and switchgear are in good condition and overall, are meeting our service level targets.

Figure 7.10.1 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 7.10.1 Circuit breakers age profile



7.10 Circuit breakers and switchgear continued

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 7.10.3.

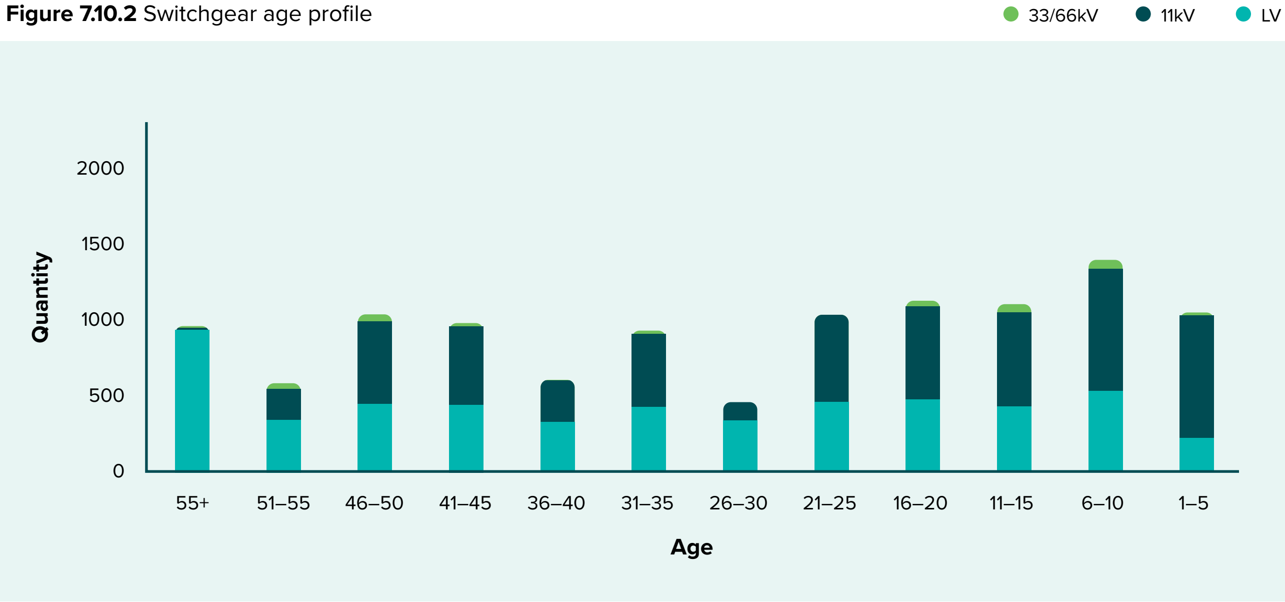
Table 7.10.3 Switchgear description by type

Voltage	Type	Description
66kV / 33kV	Substation Disconnector (DIS)	These are installed in mostly outdoor bus work in zone substations. They are generally simple hand operated devices which are used to reconfigure the substation bus for fault restoration, or for isolating plant for maintenance. The substation 66kV and 33kV disconnectors are used as isolation points in the substation structures and are mounted on support posts or hang from an overhead gantry. After a Safety in Design review, we now prefer motor operated disconnectors for safety reasons and moving forward we will continue to use motorised 66kV disconnectors.
33kV	Line ABI (pole mounted)	Installed on our rural overhead network. We no longer install 33kV line ABIs.
11kV	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.
	Line ABI (pole mounted)	There are two capability categories; load breaking or non-load breaking. We no longer install 11kV line ABIs.
	Magnefix Ring Main Switching Unit (MSU)	These MSU switches are independent manually operated, quick-make, quick-break design with all live parts fully enclosed in cast resin. Each phase is switched separately or three phases are operated simultaneously with a three phase bridge. These switches are the predominant type installed in our 11kV cable distribution network.
	Ring-main unit (RMU)	These units are arc-contained, fully enclosed metal-clad 11kV switchgear. They combine both load-break switches and vacuum circuit breakers. With motorisation and the addition of electronic protection relays they can be fully automated.
	Oil switch, fused and non-fused	These switches were installed in our 11kV cable distribution network as secondary switchgear in network and distribution building substations. They were installed before low maintenance oil-free ring-main units were proven. We no longer install these switches. Some of the installations have locally designed bus connections that are below our current standards. Incidents and difficulties in arranging outages to carry out servicing have occurred, therefore we are actively replacing these switches with ring-main units.
400V	Low voltage switch	Installed generally in distribution substations, these switches form the primary connection between 11kV/400 V transformers and the 400 V 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 7.10.4 Switches quantities by type

Voltage	Asset Type	Quantity
66kV / 33kV	Substation disconnector	282
33kV	Line ABI	8
11kV	Line switch	203
	Line ABI	632
	MSU	4,561
	RMU	133
	Oil switch, fused and non-fused	3
400V	Low voltage switches	5,416
	Total	**11,238**

Figure 7.10.2 Switchgear age profile



7.10.3 Asset health

7.10.3.1 Condition

Overall our circuit breakers and switches are in good working condition. Methods of condition monitoring, for example, partial discharge measurement has enabled us to detect defects at an early stage. The line switches, ring-main units and low voltage switches are generally in good condition. A technical investigation on a sample of our legacy switchgear in 2020 will help us better establish their end of life criteria and expected life. The condition of our line ABIs on the network is also good. However, some older types are reaching the end of their reliable service life.

The oil switches are presently maintained to a satisfactory condition. However, due to issues with safety, ageing and problematic operating mechanisms, we will replace them with modern alternatives on an as required basis.

A technical investigation on a sample of our legacy switchgear in 2020 will help us better establish their end of life criteria and expected life.

Figure 7.10.3 33kV / 66kV circuit breaker condition profile

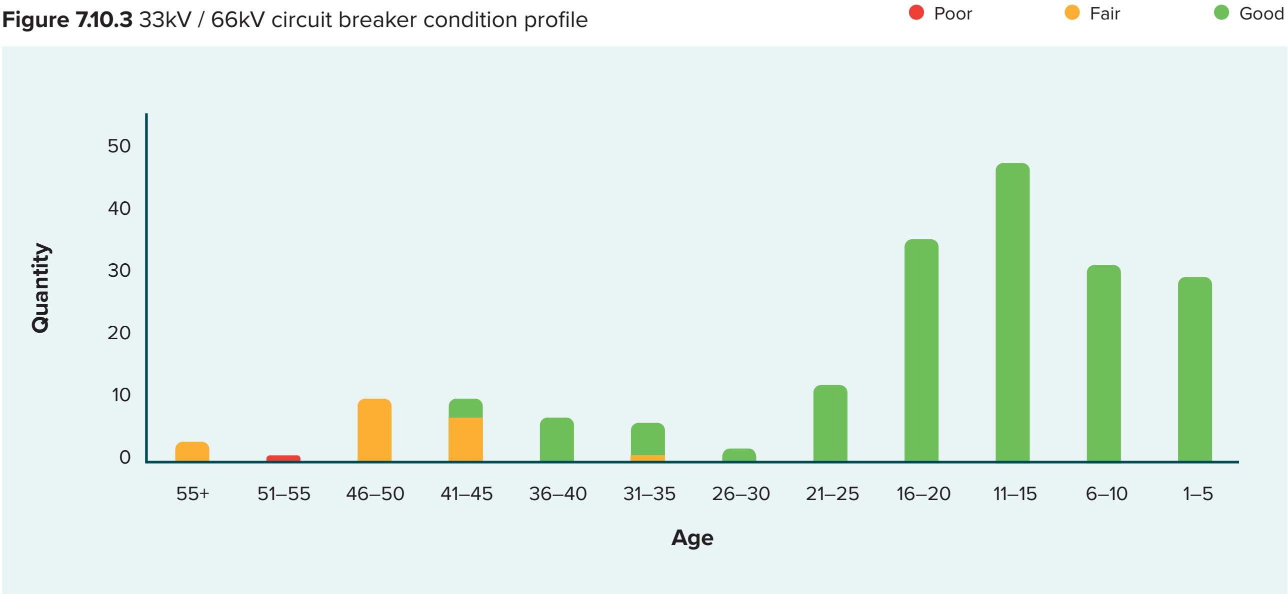
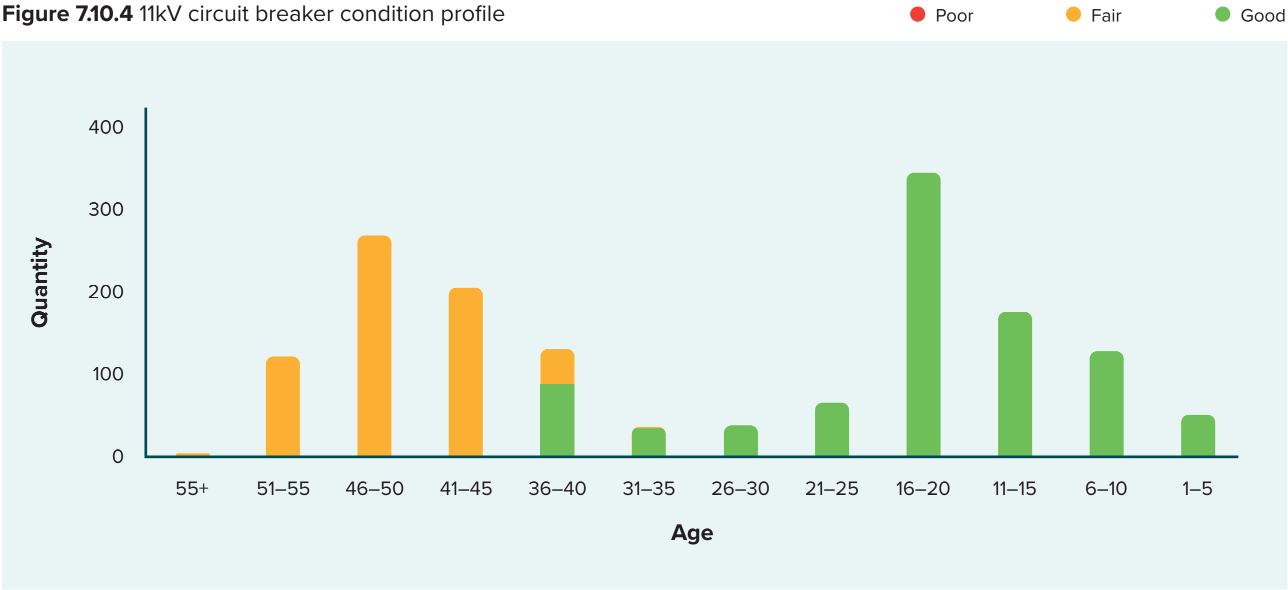


Figure 7.10.4 11kV circuit breaker condition profile



7.10.3.2 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 7.10.5.

Table 7.10.5 Performance of circuit breakers and switchgear

Voltage	Asset Type	Performance
66kV / 33kV	Substation disconnectors	Overall the performance level has been satisfactory. Some are experiencing performance issues due to misalignment. We are addressing this issue in our maintenance and replacement programmes.
66kV / 33kV / 11kV	Circuit breakers	The overall performance of our 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. As a result, in recent years several 66kV SF_6 circuit breakers have leaked and to overcome this issue we have replaced the gaskets. There is large population of aging oil filled 11kV circuit breakers in our substations. While their rate of failure is very low, a failure of these assets can be catastrophic in nature. This therefore presents a risk to maintenance personnel, as well as a significant impact on reliability should a failure occur. As a result of the critical nature of these assets, we are phasing out all oil filled circuit breakers as they reach their end of life.
33kV	Line ABI	Our remaining units are performing reliably with no recent failures. These are progressively being replaced by line circuit breakers 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	A particular model of ABI is reporting a high failure rate due to faulty insulators. Refer to Section 7.10.5.5 for the replacement programme.
	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. The defects are identified by routine inspection and testing and rectified as part of our maintenance 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.
	Oil switch, fused and non-fused	Oil switches have caused some problems periodically due to oil leaks and jammed operating mechanisms. Some of them also have design ratings that are below current standards. The use of oil as an insulating and switching medium introduces safety hazards that are not tolerable in modern equipment. For safety reasons, we are progressively replacing these switches.
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.

7.10.3.3 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 7.10.6 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 strategic drivers in Section 2.8.

Table 7.10.6 Circuit breakers and 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
Breaker contact surface degradation	Aging and corrosion high usage duty	Targeted testing and maintenance programme. 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
Electronic protection and control system	Aging and corrosion. Design and/or manufacturing quality, battery corrosion, moisture and contamination	Routine inspection, testing and maintenance and replacement if indicated
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

7.10.4 Maintenance Plan

We use both routine and reliability based inspection and maintenance for our circuit breaker 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 asset with poorer condition or reliability to maintain their performance and mitigate against failure. Our inspection testing and major maintenance are carried out at regular intervals as shown in Table 7.10.7. Note that partial discharge checks are carried out at different intervals depending on the age and location of the switchgear.

Table 7.10.7 Circuit breakers and switchgear maintenance plan

Asset	Maintenance activity	Frequency
Circuit Breaker	**Inspection or Testing** • Inspect • Thermal imaging to identify hotspots • Monitor levels of SF_6 and report any loss to atmosphere • Monitor partial discharge	1 month – Zone substation 6 months – Distribution substations 6 months – Outdoor ground mounted 12 months – Outdoor pole mounted circuit breakers 24 months – Outdoor pole mounted ABI (load-break types)
	Major Maintenance • Clean and lubricate • Repair or replace contacts, insulators and mechanisms • Profile tripping function • Service and replace oil/SF_6 • Battery replacement	Every 4 or 8 years – Zone substation 8 years – Distribution substations 4 years – Outdoor ground mounted 8 years – Outdoor pole mounted circuit breakers
66kV & 33kV Substation ABI	Inspect Maintain Infra-red camera hotspot scanning	2 monthly Every 4 years or 8 years depending on site Every 2 years
Other HV switchgear	Inspect Maintain as required	6 monthly
Low voltage switchgear	Inspect	At least 5 yearly

An annual forecast of operational expenditure in the Commerce Commission categories is shown in Table 7.10.8. 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 7.10.8 Circuit breakers and switchgear operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	260	260	260	260	260	260	260	260	260	260	**2,600**
Routine and corrective maintenance and inspections	1,205	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	**11,510**
Total	**1,465**	**1,405**	**1,405**	**1,405**	**1,405**	**1,405**	**1,405**	**1,405**	**1,405**	**1,405**	**14,110**

7.10.5 Replacement Plan

We have a proactive replacement programme for our circuit breakers and switchgear. 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.

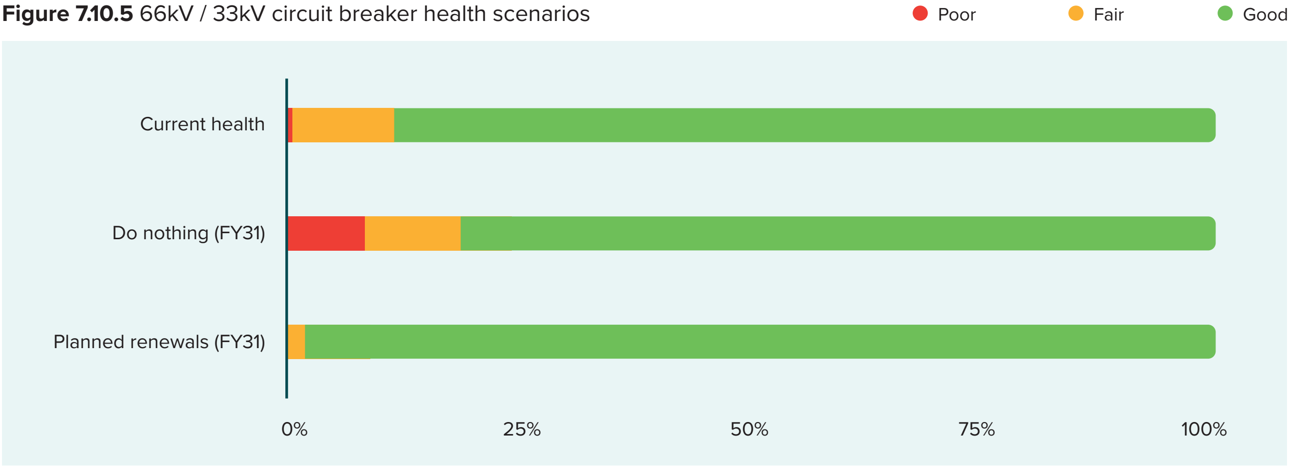
Safety issues are given a high weighting to ensure protection of the public, employees and service providers. Performance and asset condition are considered on an individual basis and are used to develop the replacement programme. The criticality and location, i.e., zone substation, is also considered 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 take into account 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 7.10.5).

Figure 7.10.5 66kV / 33kV circuit breaker health scenarios

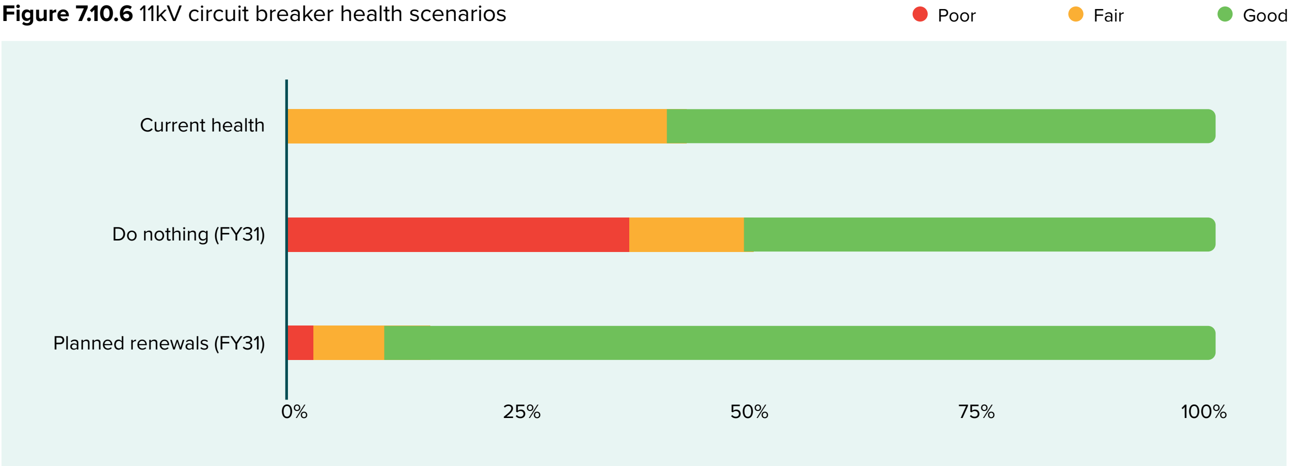


- **Do nothing scenario –** as a means of comparison, we looked at a theoretical scenario without a replacement programme. This showed the risk of a major failure of circuit breakers would increase. This poses a risk on safety of personnel and environmental impacts, which is considered to be unacceptable 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.

11kV circuit breakers

The scenario in Figure 7.10.6 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. Their replacement is an appropriate response to minimise the potential safety risks of ageing 11kV circuit breakers.

Figure 7.10.6 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 switchgear

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. Over half of the unfused MSUs will be replaced in the next 10 years. The age-based replacement rate will increase over the next two years to maintain the health and risk profile. We will also continue to replace our oil switches for safety reasons.

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 in poor condition will be replaced as part of the switchgear renewal works. It is anticipated that the replacement rate of LV switches will increase over the next two years and remain constant for the remainder of the 10 year period.

An annual forecast for our replacement capital expenditure in the Commerce Commission categories is shown in Table 7.10.9.

Table 7.10.9 Circuit breakers and switchgear replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Subtransmission	30	30	30	30	–	–	–	–	–	–	**120**
Zone substations	3,393	3,035	3,340	2,415	2,243	2,877	3,444	2,746	1,742	1,385	**26,619**
Distribution switchgear	4,993	7,035	7,360	7,805	8,220	8,095	7,715	7,795	7,375	7,375	**73,768**
Total	**8,416**	**10,100**	**10,730**	**10,250**	**10,463**	**10,972**	**11,159**	**10,541**	**9,117**	**8,760**	**100,507**

7.10.5.1 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).

7.10.6 Innovation

We replaced our ageing oil filled 11 kV indoor switchgear at our Hoon Hay zone substation with safe arc contained switchgear which contains no oil or gas, and requires minimal maintenance. The 30 new air-insulated switches are the first of their kind to be installed on our network and they replaced switchgear from the late 1960s and early 1970s with sophisticated equipment that meets modern performance, environment and safety standards.

We have 82 power transformers installed at zone substations, ranging from 2.5MVA to 60MVA.

7.11 Power transformers and voltage regulators

7.11.1 Summary

We have 82 power transformers installed at zone substations ranges from 2.5MVA to 60MVA. 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. We also have 15 regulators installed on the network to provide voltage stability which are in good condition.

7.11.2 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.

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.

Table 7.11.1 Power transformer quantities by type

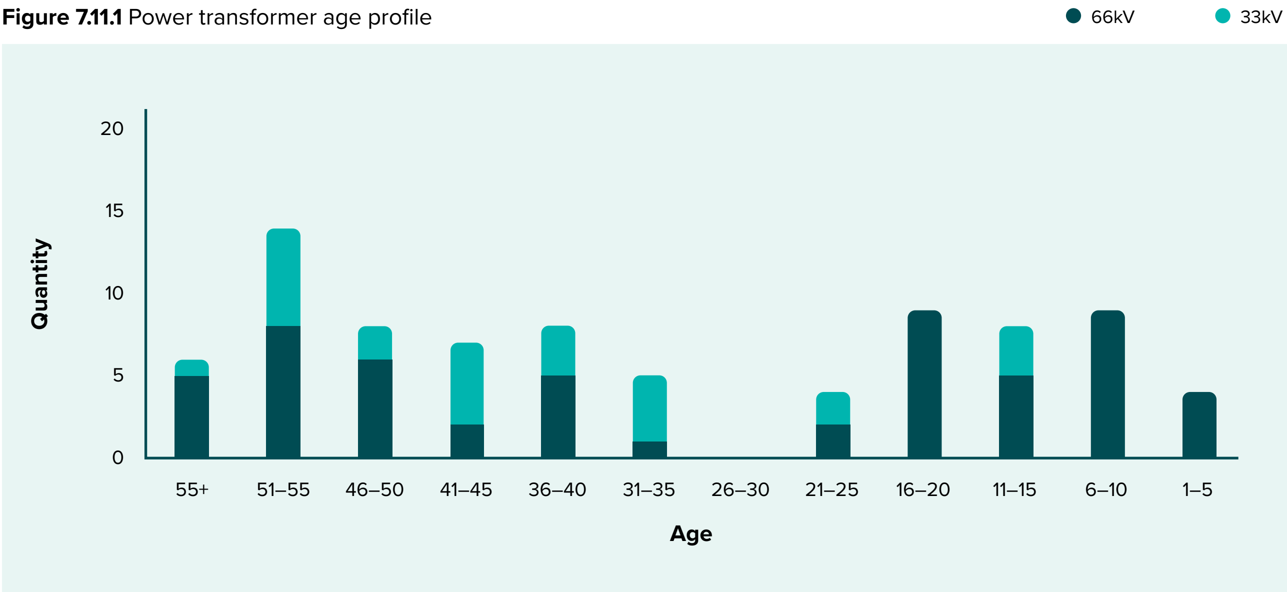
Nameplate Rating MVA	66kV	33kV
	Quantity	Quantity
30/60	2	
34/40	2	
30/36 (1Ø Banks)	5 (15)	
20/40	26	
20/30	2	
11.5/23	13	7
10/20		4
7.5/10	6	8
7.5		6
2.5		1
Total	**56 (66)**	**26**

7.11 Power transformers and voltage regulators continued

The age profile in Figure 7.11.1 shows that we have a proportion of our asset fleet that is older than the nominal asset life. The useful life of a transformer can vary greatly. Our transformers often operate well below their nominal capacity which can lengthen their asset 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. Some of our older transformers are scheduled for replacement later in this AMP period – see Section 7.11.5.

Figure 7.11.1 Power transformer age profile



Regulators
Our 11kV line voltage regulators are installed at various locations to provide capacity via voltage regulation.

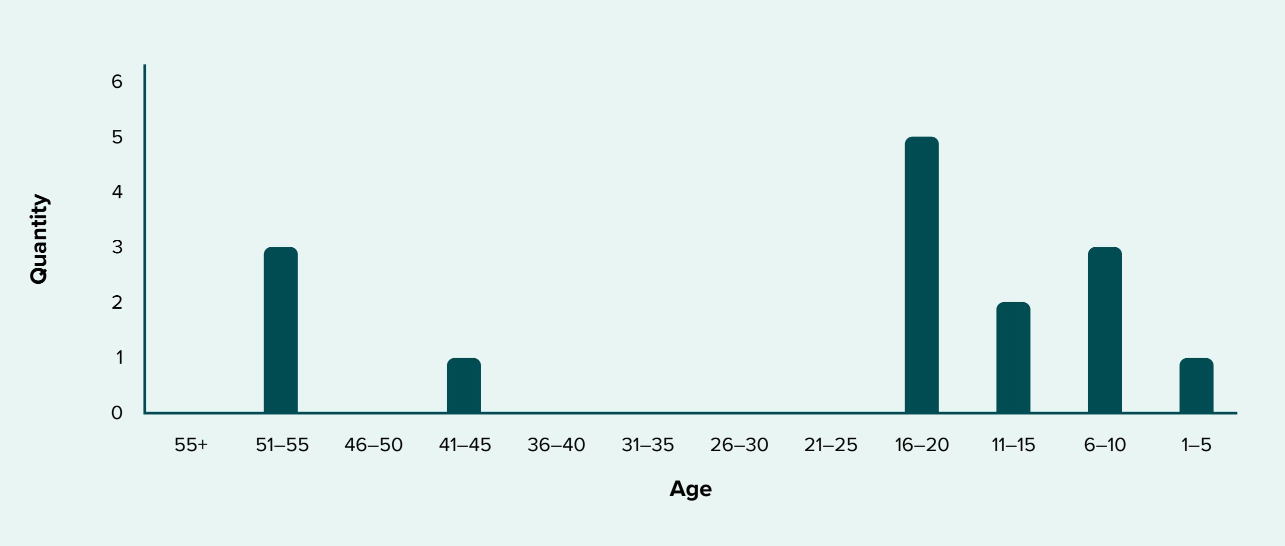
We use a wide range of ratings to cater for different load densities within our network. All regulators are oil-filled, with automatic voltage control by an on-load tap changer or induction. The quantities are listed in Table 7.11.2 and the age profile is shown in Figure 7.11.2.

Our transformers often operate well below their nominal capacity which can lengthen their asset life.

Table 7.11.2 Regulator quantities by type

Nameplate Rating MVA	Quantity
20	3
4	11
1	1
Total	**15**

Figure 7.11.2 11kV regulator age profile



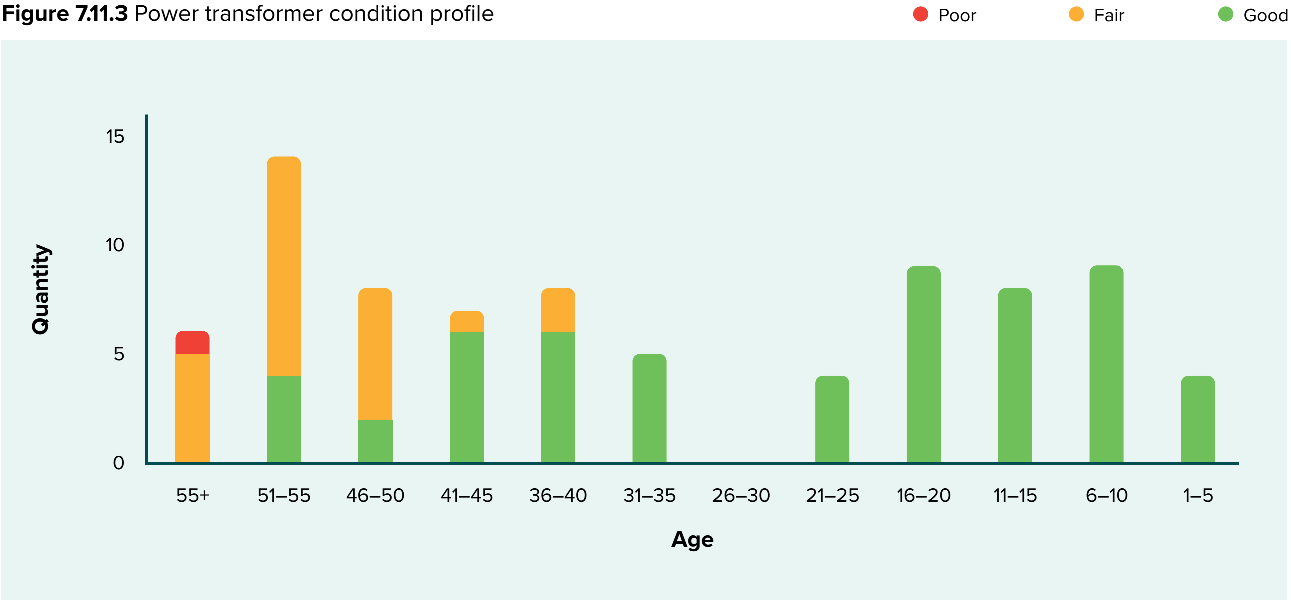
7.11.3 Asset health

7.11.3.1 Condition

Power transformer

The condition profile in Figure 7.11.3 shows that most of our transformers are in good condition. This is in part due to a number of refurbishments we have completed on many of our older power transformers. There are a small number in poor condition. These are single phase bank transformers at Addington substation. Our strategy to address these transformers is discussed further in this section.

Figure 7.11.3 Power transformer condition profile



Regulator

Three 20MVA regulators at Heathcote are an older design. They have been refurbished and are working satisfactorily. The condition of our other regulators is good.

7.11.3.2 Reliability

We set very high performance standards for power transformers. This is because we design for N-1 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.

7.11.3.3 Issues and controls

Table 7.11.3 lists the common causes of failure and the controls implemented to reduce their likelihood.

> **We set very high performance standards for power transformers.**

Table 7.11.3 Power transformer and regulator 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
		New transformers have thermally uprated papers
	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
	Cooling systems (valves, pumps and fans)	
Material degradation	Corrosion and moisture ingress due to deterioration of enclosure seals	Routine maintenance
		Monitor the moisture in the oil
		Condition the oil to remove moisture (Trojan machine)
		New transformer specifications have additional mitigations
		Refurbishment programme

7.11.4 Maintenance plan

Our maintenance activities shown in Table 7.11.4 are driven by a combination of time based inspections and reliability centred maintenance.

Table 7.11.4 Power transformer maintenance plan

Maintenance activity	Strategy	Frequency	
		Regulator	Power transformer
Inspection	Minor visual inspection and functionality check	6 monthly	2 monthly
Shutdown service	Detailed inspection and functional check	4 yearly	Annually
Oil diagnostics	DGA and oil quality tests	4 yearly	Annually
Oil treatment	Online oil treatment to reduce moisture levels	4 yearly	2 yearly or more often as required
Tap changer maintenance	Intrusive maintenance and parts replacement as per manufacturer's instructions	4 yearly	4 yearly for oil 8 yearly for vacuum
Level 1 and 2 electrical diagnostics	Polarisation index and DC insulation resistance DC Winding resistance, winding ratio test	4 yearly	4 or 8 yearly

7.11.4.1 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 7.11.5. Our forecasts are based on our assessment of transformer age, condition, and technical and financial feasibility.

Table 7.11.5 Power transformer and regulator operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	210	210	210	210	210	210	210	210	210	210	**2,100**
Routine and corrective maintenance & inspection	625	575	575	575	575	575	575	575	575	575	**5,800**
Asset replacement and renewal	820	530	240	-	-	-	-	-	-	-	**1,590**
Total	**1,655**	**1,315**	**1,025**	**785**	**785**	**785**	**785**	**785**	**785**	**785**	**9,490**

7.11 Power transformers and voltage regulators continued

7.11.5 Replacement plan

Our current replacement programme targets end of life zone substation power transformers. The programme as shown in Table 7.11.6 prevents failure rates and risk from materially increasing above current levels.

Table 7.11.6 Power transformer replacement plan

Zone substation	Details	Financial year planned
Spare	A new spare 33kV will be purchased which is intended for replacement of Shands Zone Sub T1 in FY27. By procuring this earlier we will have a contingency spare in case we find any problems during our refurbishment programme for our 33kV transformer fleet	FY23
Addington	Replace T6 and T7 transformer banks with one transformer. This transformer replacement timing is dependent on a wider network and site strategy to rationalise assets at the substation	FY28

Figure 7.11.4 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 7.11.4 Power transformer health scenarios

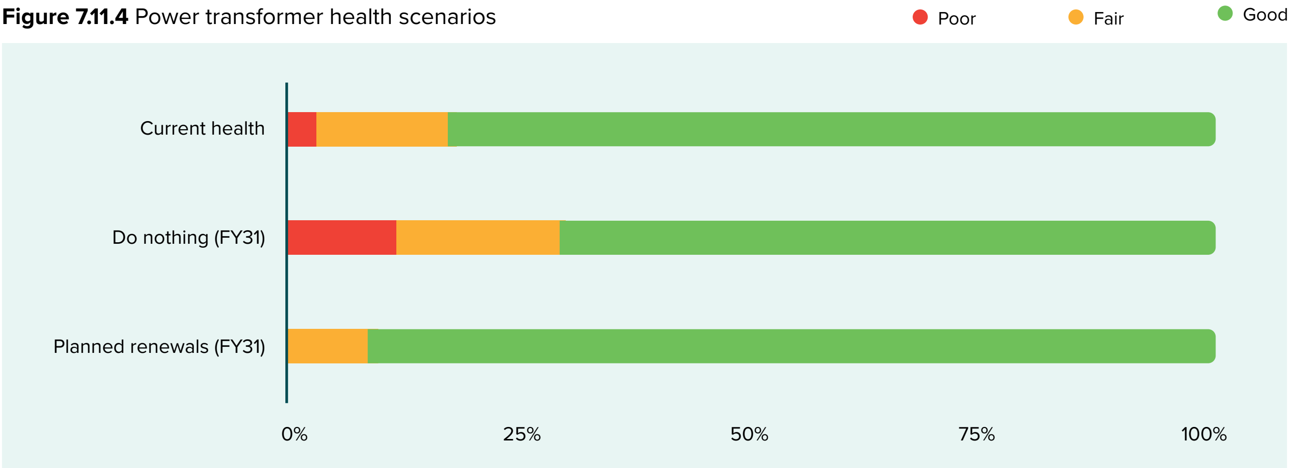


Figure 7.11.4 shows that the planned renewal scenario improves the overall condition scores of our transformer fleet. This is due to our ongoing refurbishment programme and replacement of our end of life single phase transformers. Comparing with the 'do-nothing' scenario shows that the proposed programme mitigates a substantial deterioration in asset condition. An annual summary of power transformer and regulator capital expenditure in the Commerce Commission categories is shown in Table 7.11.7.

Table 7.11.7 Power transformer and regulator replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Zone substation	600	1,270	300	-	-	-	2,600	-	-	-	**4,770**
Total	**600**	**1,270**	**300**	**-**	**-**	**-**	**2,600**	**-**	**-**	**-**	**4,770**

We have more than 11,000 distribution transformers installed on our network to transform the voltage from 11kV to 400V for customer connections.

7.12 Distribution transformers

7.12.1 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 good. We continue to maintain and replace our distribution transformers in accordance with our standard asset management practices.

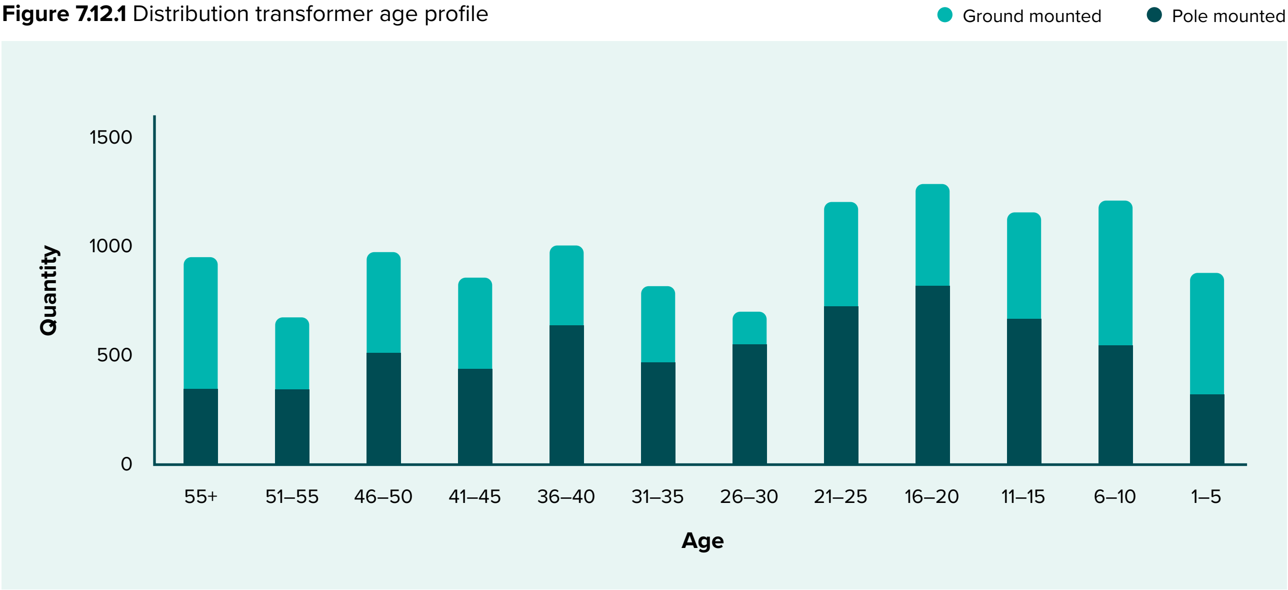
7.12.2 Asset description

Distribution transformers fall into two main categories: pole mounted or ground mounted. Pole mounted transformers range in rating from 15kVA – 300kVA. 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 7.12.1 shows the transformer quantities categorized by rating, and an age profile can be found in Figure 7.12.1.

Table 7.12.1 Distribution transformer quantities by type

Rating kVA	Ground mount	Pole mount
	Quantity	Quantity
5-100	398	6,081
150-500	4,289	363
600-1000	590	
1250-1500	31	
Total	**5,308**	**6,444**

Figure 7.12.1 Distribution transformer age profile



7.12.3 Asset health

7.12.3.1 Condition

As it can be seen in Figure 7.12.2 our ground mounted distribution transformers are in good 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 good condition and are inspected on site every six months.**

Figure 7.12.2 Distribution transformer condition profile

7.12.3.2 Reliability

The failure rate and contribution of SAIDI/SAIFI from distribution transformers is very low indicating that broadly, our current inspection, maintenance, and renewal strategies are effective. We continue to assess defects and failures, and assess our maintenance practices.

7.12.3.3 Issues and controls

Table 7.12.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.12.2 Distribution transformers failure controls

Common failure cause	Known issues	Control measures
Insulation failure	Heat	Maximum demand of larger ground mount transformers are regularly checked and replaced if overloading occurs
	Lightning	Surge arrestors fitted at cable terminations to the lines
Material degradation	Moisture ingress due to deterioration of enclosure seals Corrosion	Inspection, refurbishment and replacement programme

7.12.4 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 7.12.3.

Table 7.12.3 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 yearly	6 monthly
Workshop service	Detailed inspection and testing, assess and repair defects if economic to do so	As required	As required

An annual forecast of our operational expenditure on distribution transformers in the Commerce Commission categories is shown in Table 7.12.4.

Table 7.12.4 Distribution transformer operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Routine and corrective maintenance and inspections	260	260	260	260	260	260	260	260	260	260	**2,600**
Total	**260**	**260**	**260**	**260**	**260**	**260**	**260**	**260**	**260**	**260**	**2,600**

7.12.5 Replacement plan

Transformers taken out of the network due to capacity changes or faults are replaced where repair or maintenance proves uneconomic. An allowance has been made in the replacement budget to cover this. An annual summary of our distribution transformer replacement capital expenditure in the Commerce Commission categories is shown in Table 7.12.5.

Table 7.12.5 Distribution transformer replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Distribution substation and transformer	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	1,145	**11,450**
Total	**1,145**	**1,145**	**1,145**	**1,145**	**1,145**	**1,145**	**1,145**	**1,145**	**1,145**	**1,145**	**11,450**

7.12.5.1 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.

7.13 Protection systems

7.13.1 Summary

Our protection system consists predominately of digital Intelligent Electronic Devices (IED), a moderate quantity of electromechanical relays and a small number of 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.

7.13.2 Asset description

Protection systems are installed to provide automatic control to elements of our network and to protect it during power system faults. These systems protect all levels of the network including the low voltage system where fuses are used.

The digital electronic equipment that provides protection, control and metering functions is integrated into a single device. The functions performed by these micro-processor based devices are so wide they have been labelled IEDs.

The introduction of IEDs has allowed us to reduce costs by improving productivity and increasing system reliability and efficiency. The introduction of remote indication and control reduces labour requirements, engineering design, installation and commissioning. Operation of the system is based on existing skill sets and does not require any significant changes in the organisation.

Table 7.13.1 Relay types

Relay type	Quantity
Electro-mechanical	1,074
Micro-processor based (IED)	1,643
Total	**2,717**

7.13.3 Asset health

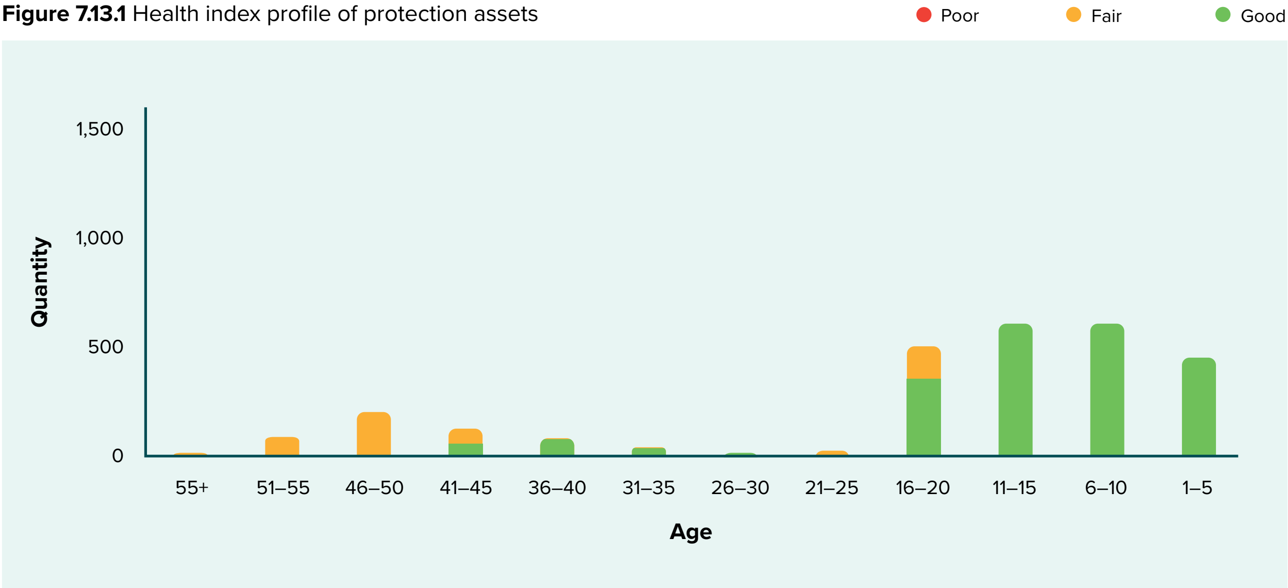
7.13.3.1 Condition

The factors that go into evaluating the health index are predominately the age but also include relay make/model failure rate, manufacturer's support and network suitability of adequacy of functions. Figure 7.13.1 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 'Fair' 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. It also is consistent with our risk appetite. Our intention with our maintenance and replacement programmes is to maintain our current asset condition and service levels.

Figure 7.13.1 Health index profile of protection assets



7.13.3.2 Reliability

Our protection systems contribute on average less than 1 per cent to SAIDI. Overall they have proven to be robust and are performing well by meeting service level targets. Examples of defects are loose termination wiring, intermittent relay faults and setting errors.

As a whole our older electro-mechanical 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 the protection system is around the ageing or obsolescence of equipment, support, parts and function. As the relays age their reliability diminishes.

A few of our substations are still utilising inferior legacy bus-zone protection schemes. These have proven to be problematic due to poor design/implementation, ageing relays and spurious tripping. Some have been replaced and the remaining sites are programmed for replacement over the coming two years.

7.13.3.3 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 7.13.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.13.2 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
	Firmware and/or software	Up to date firmware upgrade and regular testing
	Setting and or setup error	Robust testing
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 rat traps in zone substations

7.13.4 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. Regulations require they are tested at least every five years. The frequency of inspection and maintenance by location is shown in Table 7.13.3.

Table 7.13.3 Protection maintenance plan

Location	Frequency
Zone substations	2 monthly inspection and 4 yearly maintenance/testing
Distribution substations	6 monthly inspection and 8 yearly maintenance/testing
Line circuit breaker	12 monthly inspection and 8 yearly maintenance/testing

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 7.13.4 in the Commerce Commission categories.

Table 7.13.4 Protection operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Distribution & LV Lines	405	405	405	405	405	405	405	405	405	405	**4,050**
Other network assets	400	400	400	400	400	400	400	400	400	400	**4,000**
Total	**805**	**805**	**805**	**805**	**805**	**805**	**805**	**805**	**805**	**805**	**8,050**

7.13.5 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.

We will continue to progress our bus zone protection upgrade to replace the legacy problematic systems currently in place. We plan to complete on average of two substations a year over the next two years. This is optimum in terms of our objective of sustaining the work load of our resources and service providers. 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 replacement expenditure in the Commerce Commission categories is shown in Table 7.13.5.

The cost is based on historical cost from our ongoing programmes. Although the relay replacement volume is relatively constant, the varying cost through the reporting period is due to the influence of our switchgear replacement schedule.

Table 7.13.5 Protection capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Zone substation	1,375	1,325	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	**16,300**
Distribution switchgear	275	400	305	300	345	335	260	310	250	210	**2,990**
Total	**1,650**	**1,725**	**2,005**	**2,000**	**2,045**	**2,035**	**1,960**	**2,010**	**1,950**	**1,910**	**19,290**

Our 1,052km of communication cables are predominantly multi-twisted-pair copper cables located in Region A.

7.14 Communication cables

7.14.1 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. These cables are in good condition and we have no specific maintenance or proactive replacement plan at this stage. 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.

7.14.2 Asset description

Our 1,052km 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.

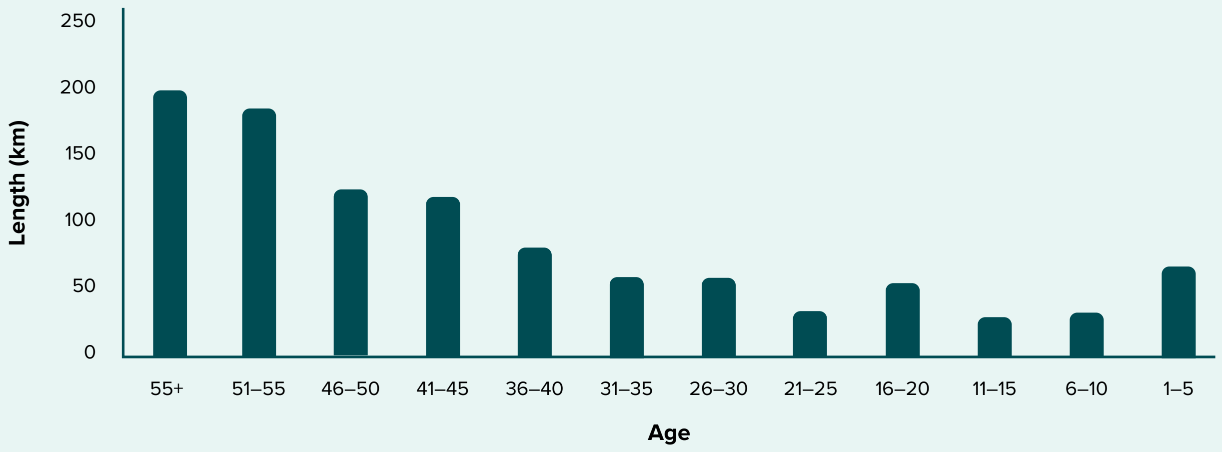
We install fibre optic communications cables, laid in ducts with all new subtransmission power cables. We also share Transpower's existing fibre-network ducts which provide us with fibre routes between our Control Centre at 565 Wairakei Rd and our zone substations. These fibre routes provide both protection signalling for various 66kV circuits, plus SCADA and other data communications.

When we require new communications routes associated with subtransmission cables or lines we now generally install fibre optic cables in ducts.

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 7.14.1. The average age of these cables is 40.

Figure 7.14.1 Communication cables age profile



7.14.3 Asset health

The overall condition of our communication cables is good. 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.

7.14.4 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 7.14.1.

Table 7.14.1 Communication cables operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	10	10	10	10	10	10	10	10	10	10	**100**
Routine and corrective maintenance & inspection	110	110	110	110	110	110	110	110	110	110	**1,100**
Total	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**1,200**

7.14.5 Replacement plan

Renewal of 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 7.14.2.

Table 7.14.2 Communication cables replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	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.

7.15 Communication systems

7.15.1 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 good condition and performing well. Additional control of the high voltage network and monitoring of the low voltage network is taking place. We are planning to upgrade our analog radios to digital. This will provide us with significantly increased signal strength on remote areas of the network.

We are planning to upgrade our analog radios to digital. This will provide us with significantly increased signal strength on remote areas of the network.

7.15.2 Asset description

7.15.2.1 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.
- **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.

7.15.2.2 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 7.15.1.

Table 7.15.2 shows the quantities of these assets by type.

Table 7.15.1 Data communication systems description

Asset	Nominal 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 between substations utilising copper communications where available. Various urban links are arranged in four rings to provide full 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 signalling. 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 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 7.15.2 Communication component quantities by type

Asset	Quantity
Cable modems	160
Voice radios	650 (includes service providers')
Cellular modems/HH PDA's	276
IP data radios	292
Radio antennae	550
Antenna cable	35
Communication masts	55
Routers/switches	2
Telephone switch	2

7.15.3 Asset health

7.15.3.1 Condition

Our new IP based equipment is on average no older than eight years and is in good condition. We have replacement programmes in place to replace technologies nearing the end of life.

7.15.3.2 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.

7.15.3.3 Issues and controls

Table 7.15.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.15.3 Communication systems failure controls

Common failure cause	Known issues	Control measures
Infrastructure component failure	Malicious damage (shooting antennae) Weather damage (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 Format Pluggable (OSFP) protocol (functional self-healing) Spares
	Human error	Training / certification Change Management
Systemic failure	Interference from third party equipment	Diversity of data/signal paths (rings) OSFP protocol (functional self-healing) Use of Licensed spectrum
	Rogue firmware updates	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 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	While we are researching our options, radio spectrum availability will dictate what can be achieved. We have researched and trialled alternative delivery technology which may drive our future directions

7.15.4 Maintenance plan

Regular inspections are carried out to ensure reliable operation of the communication systems. The plan is described in Table 7.15.4 and the associated expenditure in the Commerce Commission categories is shown in Table 7.15.5.

Table 7.15.4 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.	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	2 months
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 7.15.5 Communication systems operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	90	90	90	90	90	90	90	90	90	90	**900**
Routine and corrective maintenance and inspections	455	450	410	360	360	360	360	360	360	360	**3,835**
Total	**545**	**540**	**500**	**450**	**450**	**450**	**450**	**450**	**450**	**450**	**4,735**

7.15.5 Replacement plan

Because of the rapid improvement in technology, communications equipment has a relatively short life and equipment is not normally renewed but is replaced with more modern technologies. Our replacement plan over the AMP period is shown in Table 7.15.6 and the forecast expenditure in the Commerce Commission's categories can be found in Table 7.15.7.

Table 7.15.6 Communication system 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.
Hill top radio facility	Because of the expansion of both UHF radio protection linking and additional UHF PowerOn communications requirements, this facility is no longer fit for purpose. We will replace the facility with a self-supported support structure with antenna expansion capability and weather tight equipment housing structure.
Voice radios	After the successful trial of a digital radio system on the Banks Peninsula in FY20, we are now looking to upgrade our existing analog system over the next 3 years. The upgrade will significantly increase our signal strength 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 kept aside for such projects, with the majority going towards fibre installations. Currently there is no long-term plan for our comms architecture projects but going forward this is something we hope to develop.
Pole investigation	A number of our radio sites sit on top of steel octagonal poles. Recently, there have been reports of significant movement/vibration of these poles in windy conditions. After consultation with a specialist, we have decided that the best action is to replace these problematic poles before they start to fail.

Table 7.15.7 Communication system replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Zone substation	100	100	-	-	-	-	-	-	-	-	**200**
Other network assets	980	970	270	270	270	270	270	270	270	270	**4,110**
Quality of supply	110	110	110	110	105	105	70	70	70	70	**930**
Total	**1,190**	**1,180**	**380**	**380**	**375**	**375**	**340**	**340**	**340**	**340**	**5,240**

Because of the rapid improvement in technology, communications equipment has a relatively short life and equipment is not normally renewed but is replaced with more modern technologies.

Safety is a core driver for the use and development of our data management systems.

7.16 Advanced Distribution Management System (ADMS)

7.16.1 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 SAIDI key measures.

The network model used by PowerOn and the SCADA data that it relies on are currently limited to high voltage assets 11kV or more. Our expectation is that over the next five years we will extend the model to include low voltage assets. We also intend to introduce technology that will enable the ADMS to automatically operate network equipment or self-heal to restore supply to customers following an outage. Work underway includes a Switching Request Register (SRR) to improve service provider workflows.

7.16.2 Asset description

A ADMS is a suite of applications designed to monitor and control the distribution network and also to support decision making in the Control Room. ADMS comes in two systems: core system and ancillary system. See Table 7.16.1 for system descriptions.

Our future planning for the ADMS includes the installation of more remotely controlled switchgear and the use of the existing on-line load-flow analysis within the ADMS enables the implementation of an Adaptive Power Restoration Scheme (APRS). APRS is a ADMS application module that allows the ADMS to autonomously operate remote switching devices to isolate faults and reconfigure the network to restore supply. We will implement the SRR to improve service providers workflow.

We install new network remote terminal units when we build new sites with telemetry control. A move to implement low voltage monitoring and control will require substantial new investment.

The network model used by PowerOn and the SCADA data that it relies on are currently limited to high voltage assets 11kV or more. Our expectation is that over the next five years we will extend the model to include low voltage assets.

7.16 Advanced Distribution Management System (ADMS) continued

Table 7.16.1 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, 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 faults. 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	Field services operators are equipped with iPads and receive switching instructions directly from 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.

7.16.3 Asset health

7.16.3.1 Condition

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 their locations. The major RTU used is at end of life, and spares for some communication components and other parts are becoming very scarce. It is now important to provide a replacement strategy and delivery path for the older units.

7.16.3.2 Reliability

Generally the ADMS system runs at or near 100% reliability. There are some recent performance issues with the capacity, performance and/or availability of the ADMS and these are being addressed within our operational budgets to improve DMS operations, for example: user training, computer and network infrastructure, computer systems monitoring, settling-in time for new functionality, alarms reviews, commissioning practices.

7.16.3.3 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 7.16.2 describes the potential failure cause and mitigation controls.

> **Generally the ADMS system runs at or near 100% reliability.**

Table 7.16.2 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

7.16.4 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

The forecast expenditure in the Commerce Commission categories is shown in Table 7.16.3.

Table 7.16.3 ADMS operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	140	140	140	140	140	140	140	140	140	140	**1,400**
Routine and corrective maintenance and inspections	405	380	480	480	480	480	480	480	480	480	**4,650**
Total	**545**	**520**	**620**	**620**	**620**	**620**	**620**	**620**	**620**	**620**	**6,050**

7.16.5 Replacement plan

ADMS and RTU hardware capabilities, age and maintainability is reviewed annually and an assessment is made of equipment that needs to be programmed for replacement or renewal as mentioned in Section 7.16.3.1. An annual forecast of ADMS replacement capital expenditure in the Commerce Commission categories is shown in Table 7.16.4.

The expenditure is to support our plans for major upgrades for PowerOn in FY22 and FY26-FY27. The expenditure also allows for analytics, automated switching, and an LV model to be integrated into PowerOn over the next four years.

Table 7.16.4 ADMS replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Zone substation	20	230	230	230	230	10	-	-	-	-	**950**
Other network assets	1,500	1,430	750	1,050	1,650	1,600	100	100	100	130	**8,410**
Total	**1,520**	**1,660**	**980**	**1,280**	**1,880**	**1,610**	**100**	**100**	**100**	**130**	**9,360**

7.16.6 Innovation

We have applied a continuous improvement mind-set to our SCADA and network management systems which has, through the addition of new platforms and modules, improved our capability to operate our network. This efficiency improvement links to our safe, reliable, resilient system, health and safety, capability and future network asset management strategic drivers.

Customers benefit from enhanced and cost effective service delivery when we use state of the art systems and approaches to management of demand and system coordination to minimise capital expenditure on our network, and anticipate and maximise our response to system issues.

Our load management systems control electrical loads predominantly by injecting frequency signals over the electricity network.

7.17 Load management systems

7.17.1 Summary

Our load management systems control electrical loads predominantly by injecting frequency signals over the electricity network. The system is made up of various electrical plant and hardware/software platforms.

We will soon be undertaking a review of our current load management system architecture. This will look at how we control future Distributed Energy Resource Management (DERM) and consider integration of alternative metering sources further down the network including our protection relays, LV monitors and possibly LV smart meters. It is envisaged that any future change will transfer the load management functionality into our DMS system.

We are also actively involved in industry groups that are researching alternative technologies for DERM control.

7.17.2 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 7.17.1.

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, used for controlling 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. For example, in 2018 we converted Springston substation with a new 66/11kV transformer, 11kV switchgear and 11kV 317Hz decabit ripple plant. The existing 33kV plants remain in service to provide ripple control to the remaining 33kV substations.

Table 7.17.1 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. The master station consists of two redundant servers on dedicated hardware.	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. It is made up of multiple small injection plants connected to the zone substation feeders.	27
Ripple injection system Zellweger Decabit 317Hz	The Decabit system operates predominately within our Region B network. A number of ripple plants provide injection at zone substation feeders. The main reason for separate systems is the historical merger between distribution authorities and their separate ripple plant types.	17

7.17 Load management systems continued

7.17.3 Asset Health

7.17.3.1 Condition

The condition of the load management system is described in Table 7.17.2.

Table 7.17.2 Load management system condition

Asset	Description	Condition
Orion load management master station	The hardware and software is heading towards sunset status, with no future path provided by the manufacturer. The upgrade installed in 2017 is running, but shows some issues as part of settling in. Communications links to end-point RTUs are showing a number of small issues.	Fair
Upper South Island load management system	This system was installed 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 on the 66kV system were installed from FY04, and some components are approaching the expected useful life of 15 years. The units have been reliable to date and spare parts are available.	Good
Ripple injection system – Region B 317Hz system	The 11kV and 33kV ripple plant injection controllers are approaching their expected service life. The manufacturer no longer supports the controller type used on the 33kV ripple plants. These units have been reliable to date and there is a complete spare plant and controller if failures occur.	Fair
Measurements	The provision of resilient (i.e., redundant) load measurement is good at most sites but has deteriorated post earthquake. Light sensing for accurate timing of street lights has deteriorated to only a single measurement point.	Fair

7.17.3.2 Reliability

Overall our load management systems are achieving the required load shedding performance required to maintain service levels and to limit tariffs. No failures have occurred at peak times

7.17.3.3 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 7.17.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.17.3 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 area available on sunset operating system

7.17.4 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 7.17.5.

Table 7.17.4 Load management system maintenance plan

Asset	Maintenance activity	Frequency
Master station	Supplier review	Annually
Ripple plant	Shutdown clean, inspect and test	Annually

Table 7.17.5 Load management operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	35	35	35	35	35	35	35	35	35	35	**350**
Routine and corrective maintenance and inspections	385	325	325	325	325	325	325	325	325	325	**3,310**
Total	**420**	**360**	**360**	**360**	**360**	**360**	**360**	**360**	**360**	**360**	**3,660**

7.17.5 Replacement plan

Load management master stations
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 will consider ongoing resources and the cost of Orion 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 work based on the review is currently planned to be carried out in FY23 and FY24.

Ripple plant and controllers
We have budgets to replace components that fail. Components have different expected lives of between 15 and 40 years. The replacement expenditure in the Commerce Commission categories is shown in Table 7.17.6.

Table 7.17.6 Load management system replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Zone substation	160	160	160	160	160	160	160	160	160	-	**1,440**
Other network assets	20	770	770	70	-	570	70	70	70	-	**2,410**
Total	**180**	**930**	**930**	**230**	**160**	**730**	**230**	**230**	**230**	**-**	**3,850**

7.17.5.1 Disposal

We will retire the 33kV ripple injection plants at Moffett and Hornby substations in the near future. This will provide spares for the remaining plants at Springston and Hororata.

We manage all types of works activity using purpose-built in-house developed applications which populate a single works data repository.

7.18 Information systems

7.18.1 Summary

Our Asset Management Information Systems (AMIS) hold information about our electricity network assets and support our business processes in managing assets. Our AMIS are performing well as they are regularly maintained and frequently upgraded.

7.18.2 Asset description

The majority of our primary asset information is held in our asset database and Geographic Information System (GIS). We hold information about our network equipment from GXP connections down to individual LV pole level with a high level of accuracy. In addition to these asset registers we also hold detailed information regarding customer connections in our Connections Register and track the process of asset creation and maintenance in our Works Management system.

Geographic Information System (GIS) – Orion's GIS records our network assets according to their location, type and electrical connectivity. It interfaces with other information systems such as substation asset attribute data stored in our asset register. GeoMedia specialises in reporting and analysing geographic data. In particular, GeoMedia easily combines core GIS and third party datasets such as aerial imagery for both Orion and service provider and consultant use.

Various GIS viewer technologies enable Orion to deliver 'fit for purpose' geographic asset information within Orion premises, or off site via a secure website. In areas where internet coverage is limited, GIS datasets may be stored directly on a laptop device.

Asset database – EMS Basix, provides a central resource management application that holds details of key asset types with their current location/status. The assets covered include land, substations and all our major equipment including HV cables with less strategic types being added over time. Schedules extracted from this database are used for preventative maintenance contracts and it archives any inspection/test data gathered during the contract.

Works Management – We manage all types of works activity using purpose-built in-house developed applications which populate a single works data repository. The applications are optimised for different types of work including new connections management, general network jobs and emergency works. When a job is created in Works Management a companion job is also automatically created in the financial system (NAV) to track job related invoices.

Connections Register – Our in-house developed Connections Register holds details of all installation control points (ICP) on our network. This is linked with the industry registry. Links with our GIS systems enable accurate derivation of GXP information by ICP and the association of ICP with an interruption. Interruptions are now routinely traced within the GIS using the in-built connectivity model, and accurate information about the number of customers and interruption duration are recorded.

7.18.3 Asset health

GIS – Our GIS has adequate capacity and performance for the time frame of this plan.

Asset database – We use the most current available version of EMS Basix. We use only a subset of the capabilities of the EMS Basix database which can be applied to Works Management as well as asset tracking. The performance and capacity of the upgraded system is adequate for the time frame of this plan.

Works Management – This application was subject to a review in FY17. We found the underlying database to be sound from both an architecture and overall performance perspective. The user facing components of this system however, which are based on aging technology, are rapidly becoming unsupportable and will be refreshed over the next 12 months. The performance and capacity of the database is adequate for the time frame of this plan.

Connections Register – Its capacity and performance are adequate for the period of this plan if there are no further major changes required. The Connections Register has been modified significantly since its establishment in FY00, to support a range of new business processes. This system has however reached a "tipping point" and without a change to its underlying architecture, there is a high degree of risk in developing it further.

7.18.4 Maintenance plan

General – All our systems are supported directly by our Information Solutions team with vendor agreements for third tier support where appropriate.

License costs provide a degree of application support but are substantially 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. Our experience has been that significant support is required for the vendor to accomplish an upgrade and these costs are reflected as capital projects in our budgets.

Software releases and patches are applied to systems as necessary and only after testing. Production systems are subject to business continuity standards which include:

- an environment that includes development, test and production versions
- mirroring of systems between two facilities to safeguard against loss of a single system or a complete facility
- archiving to tapes which are stored off site at a third party
- change management processes
- least privilege security practices

GIS – this is supported directly by the Orion Information Solutions team with backup from the vendor. Support hours are pre-purchased as part of an annual maintenance agreement.

Asset database – EMS Basix and related computer infrastructure are supported directly by the Orion Information Solutions team.

Other systems – All other systems are supported directly by the Orion Information Solutions team. Some recoveries are made from salaries to capital.

An annual forecast of information system operational expenditure is shown in Table 7.18.1.

Table 7.18.1 Information system operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Routine and corrective maintenance and inspections	355	355	455	455	455	455	455	455	455	455	**4,350**
Total	**355**	**355**	**455**	**455**	**455**	**455**	**455**	**455**	**455**	**455**	**4,350**

7.18.5 Replacement plan

The replacement expenditure in the Commerce Commission's categories can be found in Table 7.18.2.

Table 7.18.2 Information systems replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Other network assets	70	550	40	190	40	40	40	40	40	40	**1,090**
Total	**70**	**550**	**40**	**190**	**40**	**40**	**40**	**40**	**40**	**40**	**1,090**

Our maintenance plan has been effective in keeping our standby generators in good condition.

7.19 Generators

7.19.1 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.

7.19.2 Asset description

We have 15 diesel generators as shown in Table 7.19.1. 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. The 110kVA unit is attached to the remote TDC (Transportable Data Centre). A 550kVA unit is attached to our main office building with and the other 550kVA unit is installed at Connetics yard in the Waterloo 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 are at Papanui. The 11kVA and 30kVA which have no synchronising gear are at Papanui. In addition, we have a new 66kVA which will be trailer mounted

Table 7.19.1 Generator types

Voltage	Type	kVA					Total	Avg age
		8 - 30	66 - 110	330 - 440	550	2,500		
400V	Mobile		2	2	1		5	9
	Building generators		2				2	
	Emergency standby	2		1	3		6	
11kV	Large generators					2	2	6
Total							**15**	

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)

7.19.3 Asset health

There have been no major mechanical issues with the generators. Our generators are in good condition.

Table 7.19.2 Generator conditions by type

Voltage	Type	Condition
400V	**Mobile**	Good condition
	Building generators	Good condition
	Emergency standby	Good condition
11kV	**Building generators**	Good condition

7.19.3.1 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.

7.19.4 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 7.19.3.

Table 7.19.3 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
Large generators (11kV, 2,500kVA)	Battery charger, alternator 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 yearly To be contracted out for the warranty period of five years.

An annual forecast of generator operational expenditure in the Commerce Commission categories is shown in Table 7.19.4.

Table 7.19.4 Generator operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Service interruptions and emergencies	-	-	-	-	-	-	-	-	-	-	**-**
Routine and corrective maintenance and inspections	40	40	40	40	40	40	40	40	40	40	**400**
Total	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**400**

7.19.5 Replacement plan

When a generator gets to the end of its economic life, analysis will be done to see if it will be replaced. The 440kVA generator has done 6,600 hours and is 13 years old. When it gets to 10,000 hrs we will assess whether it is more economic to do major maintenance or replace it with a new unit. We are planning to replace trailer mounted units to truck mounted. The replacement expenditure is covered in Section 8.7 – vehicles. Expenditure has been allocated for controller and AVR replacement from FY22 – FY27.

7.19.5.1 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.

7.19.6 Innovation

Most of our generators have been fitted with SCADA which provides alarming and monitoring. Reverse synchronising has been fitted 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 drastically improved customer service by reducing restoration times.

We have also fitted a Statcom to one truck and are planning on fitting to others. 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 drastically improved customer service by reducing restoration times.

Table 7.19.5 Generators capital expenditure (real) - $,000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Other network assets	20	20	20	20	20	20	-	-	-	-	**120**
Total	**20**	**20**	**20**	**20**	**20**	**20**	**-**	**-**	**-**	**-**	**120**

Since 2000, we have replaced most of our monitoring assets and the majority are in good condition and overall meet all our service level targets.

7.20 Monitoring and Power Quality

7.20.1 Summary

Our monitoring assets are comprised of high voltage (11kV), GXP and power quality metering. Since 2000, we have replaced most of our monitoring assets and the majority are in good condition and overall meet all our service level targets.

7.20.2 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 7.20.1 Monitoring quantities by type

Asset	Quantity	Nominal asset life	% of population
Current Transformers	49	40	50%
Voltage Transformers	36	40	37%
Quality Meters	13	15	13%
Total	**98**		

7.20.3 Asset health

7.20.3.1 Condition

We will be including metering as part of our condition-based risk management model in the near future. Generally, all metering equipment is in good condition.

7.20.3.2 Performance

Our monitoring assets overall have proven to be robust, are performing well and are meeting all the service level targets. 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.

7.20.3.3 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.

7.20.4 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 7.20.2 and the associated expenditure in the Commerce Commission's categories is shown in Table 7.20.3. Variations in operational expenditure are mainly due to the expected increase in LV monitoring costs and the number of HV meter sites tested each year.

Table 7.20.2 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 7.20.3 Monitoring operational expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Routine and corrective maintenance and inspections	245	150	85	100	105	140	160	170	170	170	**1,495**
Total	**245**	**150**	**85**	**100**	**105**	**140**	**160**	**170**	**170**	**170**	**1,495**

7.20.5 Replacement plan

Table 7.20.4 shows the replacement capex in the Commerce Commission's categories. The expenditure is based on replacing end of life meters and metering equipment as well as faulty ferroresonance capacitor banks over the next 10 years.

Table 7.20.4 Monitoring replacement capital expenditure (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Other network assets	20	20	20	20	20	20	20	20	20	20	**200**
Quality of supply	100	75	75	75	75	40	40	40	40	40	**600**
Total	**120**	**95**	**95**	**95**	**95**	**60**	**60**	**60**	**60**	**60**	**800**

8

Supporting our business

Photo: Sina Rollo, Customer Support team member.

Contents

8.1 Introduction

In this section we describe the work of the teams in Orion that together, enable our business to function. We set out what each team does, the number of people involved, and our operational and capital expenditure forecast for each team. We also describe the business information systems that support our administrative functions, and the fleet of vehicles we use to do our work and engage with the community.

8.2 Gearing up for the future

Our engagement with customers, as described in Section 4, has informed how we need to prepare for their future needs. Our customers want a safe, reliable, resilient network and one that is built ready for them to take advantage of new technologies. To deliver this, we have increased resources in our information solutions team to support business process and systems development, and position Orion appropriately to meet our customers' present and future expectations.

Our strategic focus on long term capability means we have reviewed and begun to reshape our approach to works delivery. These refinements will ensure we are able to deliver the initiatives and projects in this AMP and into the future.

Business model and capability evolution complements our ability to support a future that calls for us to have more knowledge of our network and the ability to operate with greater agility, be more customer responsive, and plan with flexibility for new technology that's opening up a world of options for us and our customers. These changes will enable us to efficiently and cost effectively build the solutions for a more connected and interactive future.

In early 2020 we appointed a Group Transformation Lead and a Strategy Programme Lead to deliver on our Purpose and progress our strategic objectives at pace. In mid 2020, we appointed a Future Network Strategic Lead to bring momentum to this key strategic driver of our AMP.

These organisational changes and other initiatives to support our community's evolving needs, delivery of the projects in this AMP and our increased focus on preparing for the future will result in a gradual increase in FTEs over the regulatory period.

The additional roles that will contribute to improvements to better meet our operational needs and our customers' expectations are in the following work streams:

- **Customer and stakeholder** – we are adding specialist dedicated resources to open up new channels to engage with our customers and progress our customer centred service design
- **Works delivery** – we have instigated an alliance project management office with our primary service delivery partner, Connetics, to support our ability to efficiently deliver as described in Section 10, and ensure a safe and quality outcome for our customers and the wider community

These changes will enable us to efficiently and cost effectively build the solutions for a more connected and interactive future.

8.3 System operations and network support

The systems operations and network support functional area covers the teams managing our network, including our Customer Support team and office-based system operations teams. Around three quarters of our people are in this functional area.

8.3.1 Infrastructure management

This team is responsible for the overall direction and management of our infrastructure group.

8.3.2 Network management

Our network team is responsible for planning our network, managing our assets and packaging network programmes. This group also consists of the asset data systems team and the Orion Development Programme, Technical.

There are four teams in the group:

Network lifecycle & development team:

- 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
- develops an annual work plan and ensures progress against the plan is updated regularly
- forecasts changes in customer behaviour and demand
- identifies network constraints and develops network and non-network solutions
- provides the planning interface with Transpower
- documents our network development plans and forecasts
- monitors and analyses the impact of emerging technology
- responsible for production of the Asset Management Plan

Network programme team:

- identifies required works and develops 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

Asset information 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

Orion Development Programme, Technical:

- this programme mentors and develops our people as they progress through their focussed training – see 8.4.1

8.3.3 Network operations

Our network operations team includes our control centre, operations improvement, field response, and network access teams.

Control centre 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

Operations improvement team:

- provides strategic direction in the operations area from identification, business case through to delivery of processes and projects that will deliver customer or safety enhancements
- delivers customer centric solutions and planning relating to how we operate the network
- coordinates the release of network equipment to service providers, while maintaining network security
- liaises with all parties to minimise planned outage frequency, size and duration
- allocates operators and generators to planned works
- notifies retailers to inform customers of planned power outages

Field response team:

- 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
- reviews applications and issues, as appropriate, close approach permits 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

- provides service providers and public safety advice and education for others who are working close to or around Orion assets
- provides stand-overs for safety on excavations or other work conducted by third parties on Orion's sub-transmission asset

8.3.4 Customer and stakeholder – customer support team

Our customer support team is a key point of contact for our customers. The team:

- operates 24/7 and responds to approximately 2,500 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

8.3.5 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
- 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

8.3.6 Works delivery team

We are currently transitioning to a Primary Service Delivery Partner (PSDP) model where the majority of the current delivery functions for Orion projects and programmes of work will be undertaken by the project management office within the PSDP. It is proposed that Connetics will undertake the role as the PSDP.

Orion will continue to be directly responsible for functions including:

- management of Orion's property assets, from kiosks to substations to office buildings
- our vegetation management programme that has a key role in customer education and interaction

8.3.7 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 SL 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

8.3.8 Procurement and land services team

This team 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. The team consists of our procurement and land services teams.

Procurement team:

- ensures appropriate contracts are in place for timely delivery of network services
- recommends appropriate contract models and frameworks
- ensures clear and unambiguous contract documentation for contract implementation
- ensures fair and reasonable contract management processes are implemented and maintained
- provides independent support for contract implementation, including:
  - contract tendering
  - support, monitoring and auditing of contract systems – including safety, quality assurance, service provider performance etc.

  - approving correct service provider payments and appropriate delegated authorities
  - third party recovery where appropriate

Land services team:

- provides land and legal services for property acquisitions and disposals and the registration of interests, for example electrical easements
- provides services for the preparation and execution of property access agreements
- provides guidance on the Resource Management Act and local government compliance
- provides environmental and compliance advice related to land functions
- provides investigation services for third party damage

8.3.9 Quality, health, safety and environment (QHSE) team

The QHSE team ensures we work safely and our community can be confident Orion contributes to a safe and healthy environment. The team:

- provides governance over and continuous improvement of the Orion QHSE systems
- provides general QHSE advice to business and other stakeholders as required
- administers Vault, our safety information management system
- leads the QHSE audit program and delivers process assurance
- leads significant investigations
- coaches our Incident Cause Analysis Method (ICAM) investigation team and builds competency
- coordinates QHSE training initiatives
- provides QHSE assurance to Orion, board and management and the Electricity Engineer’s Association

8.3.10 System operations and network support expenditure forecast

The forecast for our operational expenditure for the activities of each of these teams in FY22 dollar terms is shown in Table 8.3.1.

Notes to expenditure:

- our most significant operational expenditure in these teams is remuneration for our employees.
- this chart does not include operational expenditure on our network assets
- it also does not include the following, consistent with the operational expend forecasts that are shown in non-network operational expenditure schedule 11b in Appendix F:
  - pass-through costs, such as local authority rates and industry levies
  - depreciation
  - transmission purchases

Table 8.3.1 System operations and network support (real) – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Infrastructure management	1,335	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	**13,368**
Network management	3,009	3,137	3,104	3,076	2,950	3,025	3,004	2,973	2,948	2,948	**30,174**
Network operations	6,874	6,882	6,873	6,882	6,891	6,900	6,909	6,918	6,937	6,946	**69,012**
Customer support	628	628	628	628	628	628	628	628	628	628	**6,280**
Engineering	1,949	1,964	1,964	1,964	1,964	1,964	1,964	1,964	1,964	1,964	**19,625**
Works delivery	2,485	2,469	2,469	2,469	2,469	2,469	2,469	2,469	2,469	2,469	**24,707**
Customer connections	1,969	1,969	1,969	1,969	1,969	1,969	1,969	1,969	1,969	1,969	**19,690**
Procurement and property services	1,090	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	**10,306**
Quality, health, safety and environment	842	827	827	827	827	827	827	827	827	827	**8,285**
Asset storage	720	720	720	720	720	720	720	720	720	720	**7,200**
Less capitalised internal labour	(3,206)	(3,538)	(3,278)	(3,032)	(3,275)	(3,067)	(3,031)	(2,619)	(2,127)	(2,098)	**(29,271)**
Total	**17,695**	**17,419**	**17,637**	**17,864**	**17,504**	**17,796**	**17,820**	**18,210**	**18,696**	**18,734**	**179,376**
Totals from 1 April 2020 AMP	**18,985**	**19,005**	**19,015**	**19,030**	**19,045**	**19,065**	**19,075**	**19,090**	**19,105**	**n/a**	**n/a**

8.4 Future Capability Development

8.4.1 Orion Development Programme, Technical

We apply a structured approach to training future leaders for the industry through a four year programme that develops participants' practical and theoretical understanding of engineering. We generally aim to have 8 participants in the programme at any one time.

Of our current permanent staff, 19 people are graduates of our Development Programme, Technical. The cost of participants is covered in Table 8.3.1 under network management.

This innovation contributes to delivery of our asset management strategy focus on developing our capability as asset managers, and embracing the opportunities of future networks. Our customers benefit from our sustainable approach to building capability that ensures we remain effective stewards of our assets, now and into the future.

8.4.2 Orion Development Programme, Graduate

For the first time, in 2020 we initiated the Orion Development Programme, Graduate, and took on a university graduate to complete a two-year placement rotation through various areas of our business.

8.4.3 Energy Academy

New Zealand's energy sector is changing and with it the need for developing future capabilities that are flexible and adapt as things evolve. Through a new initiative called the Energy Academy, Orion Group is stepping up to be part of changes in capability development to ensure people in our industry are "match fit".

Orion and our subsidiary Connetics are collaborating with others across the industry to look at:

- how different parts of the industry share their knowledge
- how the industry recognises and rewards achievement
- how to ensure the industry has a strong supply of diverse workers who are excited about future opportunities in the energy sector
- reimagining the current system to provide meaningful, long term careers for people in the energy sector

8.5 Business support

Around one quarter of our people work in this functional area.

8.5.1 Leadership team

The leadership team sets the direction of the company, provides overall company leadership and oversees key stakeholder interaction.

This team also leads the Group strategy development, transformation strategy and implementation.

8.5.2 People and capability

This team provides strategic, tactical and operational support and advice to the business in the people/HR space, including payroll and wellbeing.

By supporting our leaders and managers to build capability we seek to achieve the best organisational results through our people

8.5.3 Strategic services

Strategic services ensures we have the operating model and processes in place to deliver on our Group Strategy. This includes providing the people and systems capability to ensure we have a network fit for the future. This team works across the organisation to ensure we can efficiently and effectively meet our customer's needs and expectations now and into the future.

8.5.4 Finance

This team is responsible for financial reporting and administering Orion's internal audit programme. 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.

8.5.5 Information solutions

This team is responsible for delivering our information systems, including all information technology infrastructure.

We operate maintenance agreements for larger corporate systems, financials, document management, payroll, and productivity software. Our agreements cover on-premise systems that are normally supported directly by our own people as well as off-premise, cloud based systems.

We review all software agreements annually.

Our information solutions team is in-sourced and salaries are the largest single component of its operational expenditure. Team members are divided evenly among IT services and infrastructure, system development and business change, and the administration of the real time systems which are used to operate Orion's electricity network.

Led by the Future Networks Strategic Lead the team is also is responsible for the design and delivery of Orion's future network operating model and for leading the business in understanding Distribution System Operation (DSO) and the opportunities it presents.

The Future Networks Strategic Lead also directs the work of cross functional teams that investigate, prototype and recommend solutions that affect the operation of the future network.

8.5.6 Commercial

This team's responsibilities include pricing, regulation, billing and future development. This team leads:

- our engagement with and submissions to the Commerce Commission, Electricity Authority and other industry regulators
- our network delivery pricing approach and billing to retailers and major customers

8.5.7 Customer and stakeholder

This team is responsible for engaging with our community 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

This team leads Orion's focus on sustainability:

- understanding our carbon footprint
- directs our sustainability activity on both our network and in the wider community in support of addressing climate change opportunities and issues
- builds sustainability partnerships in the community

The team also focuses on improving our customer service:

- understands our customers' needs
- co-creates service offerings with our customers and partners
- facilitates customer inspired conversations about future power options

8.5.8 Board

We have a board of six non-executive directors, with extensive governance and commercial experience.

8.5.9 Insurance

We purchase insurance to transfer specified financial risks to insurers. The fees forecast are shown in Table 8.5.1.

8.5.10 Business support operational expenditure forecast

The forecast for the activities of each of these teams in FY22 dollar terms can be found in Table 8.5.1.

8.5 Business support continued

Table 8.5.1 Business support operational expenditure – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Senior leadership	3,483	3,483	3,483	3,483	3,483	3,483	3,483	3,483	3,483	3,483	**34,830**
People and capability	1,259	1,259	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	**11,670**
Strategic services	2,537	2,537	2,537	2,537	2,537	2,537	2,537	2,537	2,537	2,537	**25,370**
Finance	1,262	1,255	1,305	1,263	1,265	1,295	1,265	1,255	1,313	1,255	**12,733**
Information solutions	4,261	4,182	4,182	4,182	4,182	4,182	4,182	4,182	4,182	4,182	**41,899**
Commercial	1,811	1,795	1,820	1,775	1,775	1,775	1,775	1,775	1,775	1,775	**17,851**
Customer and stakeholder	3,245	3,293	3,293	3,293	3,293	3,293	3,293	3,293	3,293	3,293	**32,882**
Insurance	2,569	2,641	2,735	2,832	2,932	3,035	3,141	3,250	3,362	3,477	**29,974**
Corporate property	1,257	963	963	963	963	963	963	963	963	963	**9,924**
Vehicles	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	**(12,110)**
Less capitalised internal labour	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	**(11,000)**
Total	**19,373**	**19,097**	**19,151**	**19,161**	**19,263**	**19,396**	**19,472**	**19,571**	**19,741**	**19,798**	**194,023**
Totals from 1 April 2020 AMP	**17,425**	**17,520**	**17,560**	**17,627**	**17,750**	**17,738**	**17,856**	**17,962**	**17,941**	**n/a**	**n/a**

Notes to Table 8.5.1:

- The Property expenditure shown here is before any depreciation expense is recognised as depreciation does not form part of business support operational expenditure.
- The Fleet surplus shown above excludes depreciation expense and insurance.

Table 8.5.2 Board of directors' fees and expenses

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Board of directors' fees and expenses	446	446	446	446	446	446	446	446	446	446	**4,460**
Total	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**4,460**
Totals from 1 April 2020 AMP	**445**	**445**	**445**	**445**	**445**	**445**	**445**	**445**	**445**	**445**	**4,450**

8.5.11 Business support capital expenditure forecast

Our capital expenditure forecasts for non-network assets are detailed in Appendix F, Schedule 11a. Specific comments about the composition and management of our most significant non-network assets, buildings, corporate information systems and vehicles, follow in Sections 8.7 to 8.8.

8.6 Corporate properties

8.6.1 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.
- **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.

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, which is able to provide back-up power.

As part of our Pandemic Response Plan, and to support protocols we put in place during COVID-19 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.

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

8.6.2 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
- rust and rot
- extreme weather conditions
- fire
- graffiti

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. These include:

Our property assets must meet the following criteria:

- grounds maintenance
- building services maintenance
- graffiti removal

Our budgeted maintenance costs are in Section 9.2.1.

8.6.3 Replacement plan

We have no replacement plan for our corporate properties. These assets are maintained to ensure they provide the required levels of performance. Our budgeted replacement costs are in Section 9.2.4 — Capex — Non network.

8.7 Corporate information systems

8.7.1 Asset description

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 deliver services on a system hosted by a third party where appropriate, such as our PayGlobal payroll system and parts of our website. This category 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.
- **Desktop/laptop clients and operating systems** – our choice of operating system and desktop software capacity/performance are adequate for the period 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 period 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 period of this plan.
- **Financial Management Information System (FMIS)** – our FMIS (Microsoft Nav) delivers our core accounting functions which includes general ledger, debtors, creditors, job costing, fixed assets and tax registers.

8.7.2 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 and software releases and patches are applied to systems as necessary and only after testing.

Production systems are subject to business continuity standards which include:

- an environment that includes development, test and production versions
- mirroring of systems between two facilities to safeguard against loss of a single system or a complete facility
- archiving to tapes which are stored off site at a third party
- change management processes
- least privilege security practices

Our budgeted maintenance costs are shown in Section 9.2.1.

8.7.3 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.

All project costs are capitalised, including around $0.3m of software development labour per annum.

Our budgeted replacement costs are shown in Section 9.2.4.

8.8 Vehicles

8.8.1 Asset description

We own 102 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 36% 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.

8.8.2 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.

Our budgeted maintenance costs are in Section 9.2.3.

Around 36% of our passenger fleet has electric drive capability.

8.8.3 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.

Our budgeted replacement costs are in Section 9.2.4.

8.8.3.1 Creation/ acquisition plan

The aim is to have the right vehicle and driver to 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

8.8.3.2 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
Electric Vehicle (EV)	7	6 years
Plug-in Hybrid EV (PHEV)	20	6 years
Other	49	4 years on average (earlier for high km's)
Total	**102**	

9

Financial forecasting

$272m

Network operating expenditure

$378m

Non-network operating expenditure

$746m

Capital expenditure

Photo: Orion’s network extends out to sea, lighting up New Brighton Pier.

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.

9.1.1 Opex – network

Table 9.1.1 Opex network – $000

Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Subtransmission overhead lines	985	1,810	1,680	1,775	2,015	2,335	2,280	2,330	2,315	2,265	**19,790**
11kV overhead lines	7,330	7,110	8,010	8,110	7,510	6,710	6,710	6,710	7,510	7,510	**73,220**
400V overhead lines	4,620	4,410	3,610	3,610	3,510	4,310	4,310	4,310	3,510	3,510	**39,710**
Storms	245	245	245	245	245	245	245	245	245	245	**2,450**
Earths	355	325	300	275	295	335	325	300	275	295	**3,080**
Subtransmission underground cables	640	540	540	140	140	140	140	140	140	140	**2,700**
11kV underground cables	2,100	2,100	2,100	2,100	2,150	2,150	2,150	2,150	2,150	2,150	**21,300**
400V underground cables	2,895	2,895	2,895	2,895	2,895	2,895	2,895	2,895	2,895	2,895	**28,950**
Communication cables	120	120	120	120	120	120	120	120	120	120	**1,200**
Asset information	355	355	455	455	455	455	455	455	455	455	**4,350**
Monitoring and Power Quality	245	150	85	100	105	140	160	170	170	170	**1,495**
Protection	805	805	805	805	805	805	805	805	805	805	**8,050**
Communication systems	545	540	500	450	450	450	450	450	450	450	**4,735**
Control systems	545	520	620	620	620	620	620	645	620	620	**6,050**
Load management	420	360	360	360	360	360	360	360	360	360	**3,660**
Switchgear	1,465	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	**14,110**
Transformers	1,915	1,575	1,285	1,045	1,045	1,045	1,045	1,045	1,045	1,045	**12,090**
Substations	855	715	715	715	715	715	715	715	715	715	**7,290**
Generators (fixed)	40	40	40	40	40	40	40	40	40	40	**400**
Buildings and enclosures	1,200	1,200	1,200	1,200	1,350	1,350	1,350	1,350	1,350	1,350	**12,900**
Grounds	455	455	455	455	455	455	455	455	455	455	**4,550**
Total	**28,135**	**27,675**	**27,425**	**26,920**	**26,685**	**27,080**	**27,035**	**27,095**	**27,030**	**27,000**	272,080
Totals from 1 April 2020 AMP	**27,065**	**26,852**	**26,072**	**25,806**	**25,818**	**25,838**	**25,858**	**25,647**	**25,618**	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	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
System interruptions and emergencies	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	**82,000**
Vegetation	4,520	4,300	4,400	4,500	4,000	4,000	4,000	4,000	4,000	4,000	**41,720**
Routine & corrective maintenance and inspections	12,940	13,335	13,395	13,430	13,525	13,920	13,885	13,890	13,825	13,795	**135,940**
Asset replacement and renewals	2,475	1,840	1,430	790	960	960	950	1,005	1,005	1,005	**12,420**
Total	**28,135**	**27,675**	**27,425**	**26,920**	**26,685**	**27,080**	**27,035**	**27,095**	**27,030**	**27,000**	**272,080**
Totals from 1 April 2020 AMP	**27,065**	**26,852**	**26,072**	**25,806**	**25,818**	**25,838**	**25,858**	**25,647**	**25,618**	**n/a**	**n/a**

9.1.3 Opex contributions revenue

Table 9.1.3 Opex contributions revenue – $000

Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
USI load management	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	**(1,000)**
Network recoveries	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	**(10,000)**
Total	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(11,000)**
Totals from 1 April 2020 AMP	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**n/a**	**n/a**

9.1.4 Capex summary

Table 9.1.4 Capex summary – $000

Category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Customer connections/ network extensions	11,664	9,553	9,257	9,257	9,257	9,257	9,257	9,257	9,257	9,257	**95,273**
Asset relocations	2,620	6,420	6,620	1,500	1,250	1,250	1,700	1,400	1,400	1,400	**25,560**
HV minor projects	5,200	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	**36,700**
LV projects	1,070	1,054	1,350	1,330	1,561	1,586	1,803	1,774	350	350	**12,228**
HV major projects	20,795	23,504	18,327	18,382	21,268	10,810	16,753	10,544	5,344	5,286	**151,013**
Replacement	31,521	36,381	35,441	34,951	37,569	43,298	35,873	33,051	28,482	27,885	**344,452**
Capitalised internal labour	3,206	3,538	3,278	3,032	3,274	3,067	3,031	2,619	2,127	2,098	**29,270**
Total	**76,076**	**83,950**	**77,773**	**71,952**	**77,679**	**72,768**	**71,917**	**62,145**	**50,460**	**49,776**	**694,496**
Totals from 1 April 2020 AMP	**67,415**	**99,846**	**71,962**	**67,111**	**77,151**	**65,948**	**63,224**	**53,316**	**52,763**	**n/a**	**n/a**

9.1 Network expenditure forecasts continued

9.1.5 Capital contributions revenue

Table 9.1.5 Capital contributions revenue – $000

Category	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**Total**
Asset relocations	(1,781)	(4,581)	(4,741)	(915)	(790)	(790)	(1,105)	(865)	(865)	(865)	**(17,298)**
Customer connections / network extensions	(1,119)	(952)	(892)	(880)	(880)	(880)	(880)	(880)	(880)	(880)	**(9,123)**
Total	**(2,900)**	**(5,533)**	**(5,633)**	**(1,795)**	**(1,670)**	**(1,670)**	**(1,985)**	**(1,745)**	**(1,745)**	**(1,745)**	**(26,421)**
Totals from 1 April 2020 AMP	**(7,335)**	**(4,609)**	**(1,627)**	**(1,490)**	**(1,970)**	**(1,970)**	**(3,955)**	**(1,790)**	**(1,490)**	**n/a**	**n/a**

9.1.6 Capex – Customer connections / network extension

Table 9.1.6 Capex – Customer connections / network extension – $000

Category	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**Total**
General connections	4,723	3,627	3,478	3,478	3,478	3,478	3,478	3,478	3,478	3,478	**36,174**
Large connections	1,754	1,344	1,284	1,284	1,284	1,284	1,284	1,284	1,284	1,284	**13,370**
Subdivisions	2,592	1,987	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	**19,779**
Switchgear purchases	847	847	847	847	847	847	847	847	847	847	**8,470**
Transformer purchases	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	1,748	**17,480**
Total	**11,664**	**9,553**	**9,257**	**9,257**	**9,257**	**9,257**	**9,257**	**9,257**	**9,257**	**9,257**	**95,273**
Totals from 1 April 2020 AMP	**9,185**	**9,185**	**8,895**	**8,895**	**8,895**	**8,895**	**8,895**	**8,895**	**8,895**	**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	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**Total**
FY22 AMP	2,620	6,420	6,620	1,500	1,250	1,250	1,700	1,400	1,400	1,400	**25,560**
Contributions	(1,781)	(4,581)	(4,741)	(915)	(790)	(790)	(1,105)	(865)	(865)	(865)	**(17,298)**
Total	**839**	**1,839**	**1,879**	**585**	**460**	**460**	**595**	**535**	**535**	**535**	**8,262**
Totals from 1 April 2020 AMP	**870**	**410**	**410**	**285**	**405**	**405**	**735**	**585**	**285**	**n/a**	**n/a**

9.1.8 Capex – replacement

Table 9.1.8 Capex – replacement – $000

Project	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Subtransmission overhead lines	820	1,260	990	1,025	1,080	3,480	980	3,480	980	980	**15,075**
11kV overhead lines	6,225	6,896	8,896	9,406	11,336	13,846	14,244	13,020	12,510	12,510	**108,889**
400V overhead lines	830	830	440	440	440	395	395	395	320	320	**4,805**
Subtransmission underground cables	50	50	50	50	50	50	50	50	50	50	**500**
11kV underground cables	300	300	100	100	100	100	100	100	100	100	**1,400**
400V underground cables	7,165	7,220	7,220	7,220	7,220	7,320	1,500	570	570	570	**46,575**
Communication cables	80	80	80	80	80	80	80	80	80	80	**800**
Monitoring and Power Quality	120	95	95	95	95	60	60	60	60	60	**800**
Protection	1,650	1,725	2,005	2,000	2,045	2,035	1,960	2,010	1,950	1,910	**19,290**
Communication systems	1,190	1,180	380	380	375	375	340	340	340	340	**5,240**
Control systems	1,520	1,660	980	1,280	1,880	1,610	100	100	100	130	**9,360**
Asset management systems	70	550	40	190	40	40	40	40	40	40	**1,090**
Load management	180	930	930	230	160	730	230	230	230	-	**3,850**
Switchgear	8,416	10,100	10,730	10,250	10,463	10,972	11,159	10,541	9,117	8,760	**100,508**
Transformers	1,745	2,415	1,445	1,145	1,145	1,145	3,745	1,145	1,145	1,145	**16,220**
Substations	810	810	810	810	810	810	660	660	660	660	**7,500**
Generators (fixed)	20	20	20	20	20	20	-	-	-	-	**120**
Buildings and enclosures	180	110	80	80	80	80	80	80	80	80	**930**
Grounds	150	150	150	150	150	150	150	150	150	150	**1,500**
Total	**31,521**	**36,381**	**35,441**	**34,951**	**37,569**	**43,298**	**35,873**	**33,051**	**28,482**	**27,885**	**344,452**
Totals from 1 April 2020 AMP	**30,292**	**33,535**	**33,480**	**37,527**	**36,720**	**42,194**	**33,999**	**28,432**	**26,509**	**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	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Subtransmission	900	1,340	1,070	1,105	1,130	3,530	1,030	3,530	1,030	1,030	**15,695**
Zone Substation	5,998	6,470	6,080	4,855	4,683	5,097	8,254	4,956	3,952	3,435	**53,780**
Distribution & LV Lines	6,090	6,761	8,661	9,171	11,101	11,566	12,189	10,965	10,380	10,380	**97,264**
Distribution & LV Cables	715	770	570	570	570	670	670	670	670	670	**6,545**
Distribution substations & transformers	1,555	1,555	1,555	1,555	1,555	1,555	1,405	1,405	1,405	1,405	**14,950**
Distribution Switchgear	5,793	7,960	8,190	8,630	9,090	8,955	8,275	8,405	7,925	7,885	**81,108**
Other network assets	3,345	4,425	2,455	2,205	2,585	3,070	1,050	1,050	1,050	1,010	**22,245**
Quality of Supply	135	110	110	110	105	105	70	70	70	70	**955**
Other reliability safety and environment	6,990	6,990	6,750	6,750	6,750	8,750	2,930	2,000	2,000	2,000	**51,910**
Total	**31,521**	**36,381**	**35,441**	**34,951**	**37,569**	**43,298**	**35,873**	**33,051**	**28,482**	**27,885**	**344,452**
Totals from 1 April 2020 AMP	**30,292**	**33,535**	**33,480**	**37,527**	**36,720**	**42,194**	**33,999**	**28,432**	**26,509**	**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.

Table 9.2.1 System operations and network support – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Infrastructure management	1,335	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	**13,368**
Network management	3,009	3,137	3,104	3,076	2,950	3,025	3,004	2,973	2,948	2,948	**30,174**
Network operations	6,874	6,882	6,873	6,882	6,891	6,900	6,909	6,918	6,937	6,946	**69,012**
Customer Support	628	628	628	628	628	628	628	628	628	628	**6,280**
Engineering	1,949	1,964	1,964	1,964	1,964	1,964	1,964	1,964	1,964	1,964	**19,625**
Works delivery	2,485	2,469	2,469	2,469	2,469	2,469	2,469	2,469	2,469	2,469	**24,706**
Customer connections	1,969	1,969	1,969	1,969	1,969	1,969	1,969	1,969	1,969	1,969	**19,690**
Procurement and property services	1,090	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	1,024	**10,306**
Quality, health, safety and environment	842	827	827	827	827	827	827	827	827	827	**8,285**
Asset storage	720	720	720	720	720	720	720	720	720	720	**7,200**
Less capitalised internal labour	(3,206)	(3,538)	(3,278)	(3,032)	(3,275)	(3,067)	(3,031)	(2,619)	(2,127)	(2,098)	**(29,271)**
Total	**17,695**	**17,419**	**17,637**	**17,864**	**17,504**	**17,796**	**17,820**	**18,210**	**18,696**	**18,734**	**179,375**
Totals from 1 April 2020 AMP	**18,985**	**19,005**	**19,015**	**19,030**	**19,045**	**19,065**	**19,075**	**19,090**	**19,105**	**n/a**	**n/a**

9.2.2 Board of directors' fees and expenses

Table 9.2.2 Board of directors' fees and expenses – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Board of directors' fees and expenses	446	446	446	446	446	446	446	446	446	446	**4,460**
Total	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	4,460
Totals from 1 April 2020 AMP	**445**	**445**	**445**	**445**	**445**	**445**	**445**	**445**	**445**	n/a	n/a

9.2 Network expenditure forecasts continued

9.2.3 Business support

Table 9.2.3 Business support – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Senior leadership	3,483	3,483	3,483	3,483	3,483	3,483	3,483	3,483	3,483	3,483	**34,830**
People and capability	1,259	1,259	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	**11,670**
Strategic services	2,537	2,537	2,537	2,537	2,537	2,537	2,537	2,537	2,537	2,537	**25,370**
Finance	1,262	1,255	1,305	1,263	1,265	1,295	1,265	1,255	1,313	1,255	**12,733**
Information solutions	4,261	4,182	4,182	4,182	4,182	4,182	4,182	4,182	4,182	4,182	**41,899**
Commercial	1,811	1,795	1,820	1,775	1,775	1,775	1,775	1,775	1,775	1,775	**17,851**
Customer and stakeholder	3,245	3,293	3,293	3,293	3,293	3,293	3,293	3,293	3,293	3,293	**32,882**
Insurance	2,569	2,641	2,735	2,832	2,932	3,035	3,141	3,250	3,362	3,477	**29,974**
Corporate property	1,257	963	963	963	963	963	963	963	963	963	**9,924**
Vehicles	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	(1,211)	**(12,110)**
Less capitalised internal labour	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	**(11,000)**
Total	**19,373**	**19,097**	**19,151**	**19,161**	**19,263**	**19,396**	**19,472**	**19,571**	**19,741**	**19,798**	**194,023**
Totals from 1 April 2020 AMP	**17,425**	**17,520**	**17,560**	**17,627**	**17,750**	**17,738**	**17,856**	**17,962**	**17,941**	**n/a**	**n/a**

9.2.4 Capex non-network

Table 9.2.4 Capex non-network – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Plant and vehicles	1,176	1,565	954	1,146	1,179	1,072	1,786	998	809	1,141	**11,826**
Information technology	5,130	3,693	1,517	1,738	1,787	783	1,553	950	895	920	**18,966**
Corporate properties	789	290	291	292	293	794	295	296	297	298	**3,935**
Tools and equipment	634	457	417	417	442	407	407	407	407	407	**4,402**
Capitalised internal labour	1,100	1,122	1,151	1,179	1,209	1,240	1,271	1,304	1,337	1,370	**12,283**
Total	**8,829**	**7,127**	**4,330**	**4,772**	**4,910**	**4,296**	**5,312**	**3,955**	**3,745**	**4,136**	**51,412**
Totals from 1 April 2020 AMP	**4,648**	**5,962**	**2,950**	**3,676**	**3,165**	**2,606**	**4,471**	**2,531**	**2,713**	**n/a**	**n/a**

9.3 Total capital and operations expenditure

Table 9.3.1 Total capital and operations expenditure – $000

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total
Capital expenditure	84,904	91,077	82,103	76,724	82,589	77,064	77,229	66,100	54,204	53,912	**745,906**
Operational expenditure	65,649	64,637	64,659	64,391	63,898	64,718	64,773	65,322	65,913	65,978	**649,938**
Total	**150,553**	**155,714**	**146,762**	**141,115**	**146,487**	**141,782**	**142,002**	**131,422**	**120,117**	**119,890**	**1,395,844**
Totals from 1 April 2020 AMP	**135,983**	**138,630**	**138,004**	**133,695**	**143,374**	**131,640**	**130,929**	**118,991**	**118,585**	**n/a**	**n/a**

9.4 Changes from our previous forecasts

Overall, there has been a small increase of $5m in the cost of labour to maintain and replace our overhead and substation assets. This is less than 1% of the total network opex and capex forecast.

9.4.1 Opex – network

Our opex forecast is broadly consistent with last year's forecasts with the exceptions of:

- Overhead system – increase of $6.5m due to our improved pole inspection process and targeted vegetation trimming projects
- Switchgear, transformers and substations – adjustment of $2m to reflect more proactive work being carried out doing the maintenance rounds of these asset classes

9.4.2 Capex – asset replacement

Our replacement programme is also broadly consistent with last year's forecast with these significant exceptions:

- Overhead system – increase of $4.7m due to new programme to upgrade LV conductors and expected increase in the number of proactively replacing defective poles due to the improved pole inspection process
- Switchgear – increase of $3m due to our new LV panel replacement programme and $7m due to refinement of circuit breaker unit cost per job based on recently completed jobs
- Secondary system – decrease of $4.6m due to our identification of opportunities to align protection projects

9.4.3 Connections / extensions

We anticipate that the surge in new residential housing will continue into next year, so we have increased our FY22 forecast connection budget by $2.1m.

9.4.4 Asset relocations

Underground conversions are carried out predominantly in conjunction with road works undertaken at the direction of Selwyn District Council, Christchurch City Council and/or the NZ Transport Agency. The increase this year is due to new projects identified by road authorities and our desire to make economical use of these opportunities.

9.4.5 HV minor projects

Due to two large customer driven reinforcement projects we have increased the FY22 HV minor project budget to $5.2m, while the FY23 – 31 years remain at a constant $3.5m.

9.4.6 LV projects

No change from the 2020 AMP forecast.

9.4.7 Major projects

Although the network connections and extensions budget has remained relatively stationary due to no forecast increases in the connection numbers, we have observed that the underlying growth in existing as well as large scale commercial and industrial connections has eroded our capacity at a subtransmission level. This has triggered the need to include the extension of our subtransmission network and the construction of new zone substations into our forecast expenditure.

Other alterations from the last year's 2020 AMP Update are driven by the requirement to coordinate projects around Christchurch City Council and Waka Kotahi (NZ Transport Agency) works as well as balancing contractor resource.

The changes include:

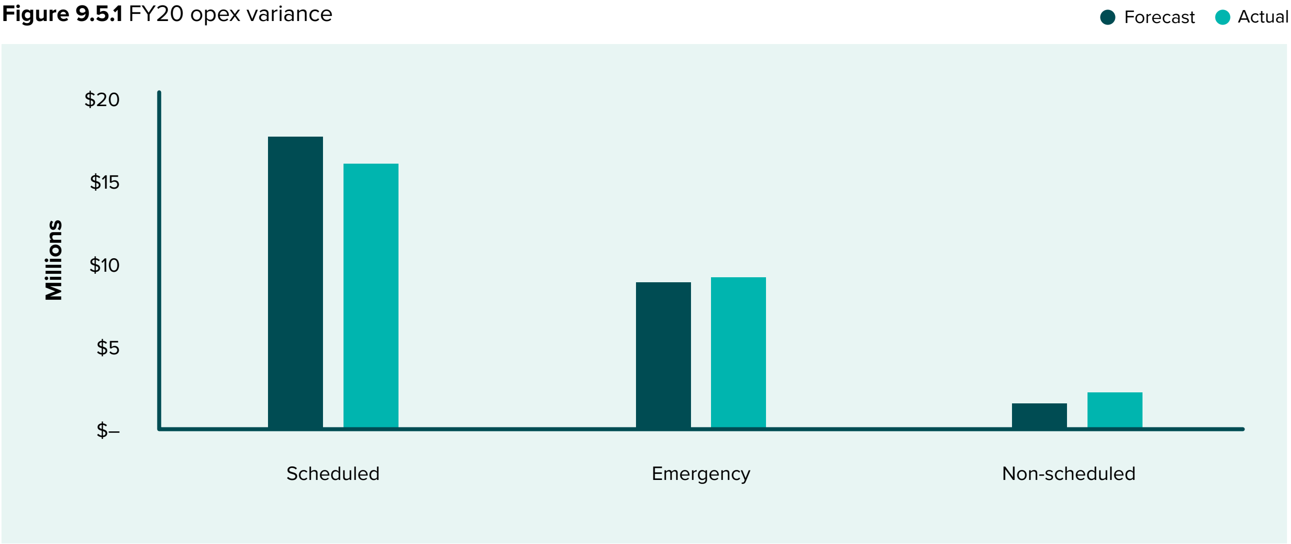
- Construction of the Belfast ZS to Papanui ZS 66kV cable in FY22 – 23 (Project 942) instead of the Belfast ZS to McFaddens ZS cable 66kV links (Project 491) due to the timing of the Christchurch Northern Motorway completion. Project 491 is now forecast for construction in FY27 – 28
- A large industrial customer capacity upgrade requiring the addition of a 66/11kV transformer at Norwood ZS in FY24 – 25 (Project 1070)
- Upgrade of the 66/11kV transformer at Springston ZS to meet the growth of Lincoln township and the University (Project 1099)
- Construction of the 23MVA rated Greenpark ZS to replace the 10MVA Lincoln ZS in FY28 – 29 to support the growing Lincoln township from the east (Project 842). There are also several enabling projects to reinforce the subtransmission supply to the new ZS
- Redevelopment of the Shands Rd ZS site as part of the enveloping industrial subdivision. This project is timed to coincide with the 11kV and 33kV switchgear replacement at Shands Rd ZS

9.5 Expenditure variation

9.5.1 Network opex variation

Our maintenance costs for FY20 were $28.0m, compared with our budget forecast of $28.7m. The main reason for the under-expenditure of $0.7m is in scheduled works due to service providers unable to complete works due to planning/resource issues. The network opex breakdown is shown in Figure 9.5.1.

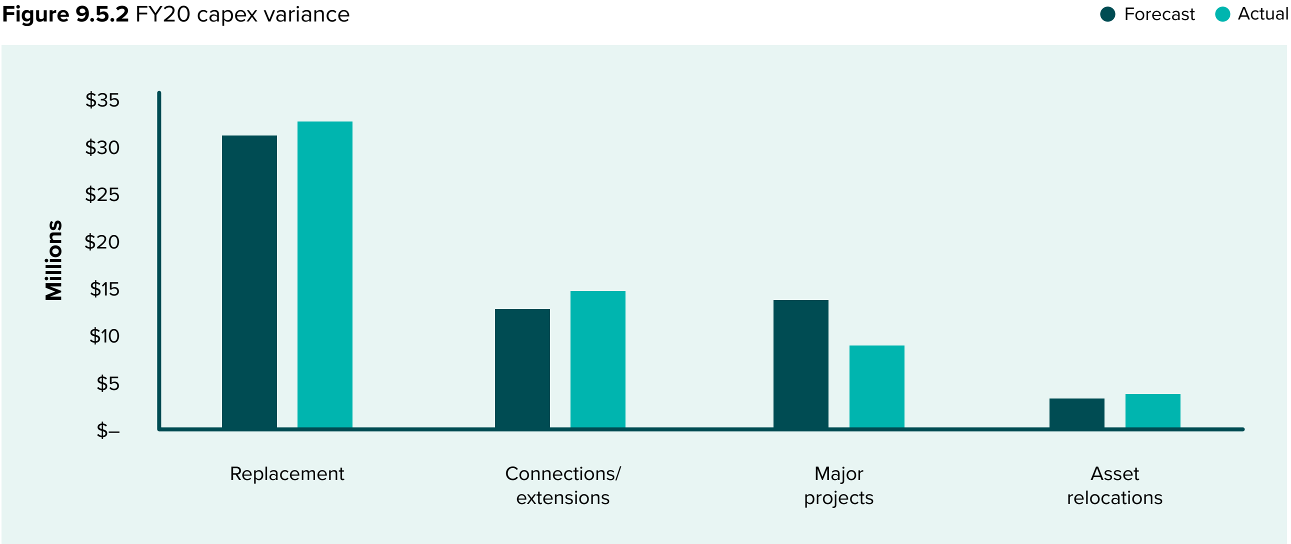
Figure 9.5.1 FY20 opex variance



9.5.2 Network capex variation

Our network capex actuals for FY20 were $60.5m, compared with our budget forecast of $61.5m. The breakdown is shown in Figure 9.5.2.

Figure 9.5.2 FY20 capex variance



Overall there was an under-expenditure of $1m.
This is made up of:

- $4.8m under-spent in major projects due deferment by one year of works associated with Belfast Zone Substation
- $1.7m over-spent due to higher than expected costs in the customer connections area
- $1.7m over-spent in replacement largely due to increase in labour cost for circuit breaker installation
- $0.4m over-spent in asset relocations mainly due to carry-over work from previous year, driven by NZ Transport Agency

10

Our ability to deliver

Photo: Connetics' Tony Williamson and Ventia crew working at Hawthornden substation to reconfigure the power supply from our Islington Zone substation.

Contents

10.1 Introduction

This section describes our:

- 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 on time
- approach to works prioritisation and optimising resources

10.2 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 service – we engage them for specified scopes of work or for contracts over specific periods to meet the needs of our AMP objectives.

The key objective of our contractual relationships is to actively specify, monitor and control the contract to ensure that services and materials are delivered on time, at an agreed cost and to specified requirements. Our contracts are founded on AS/NZS standard conditions for capital, maintenance, and emergency works contracts.

Our Service Providers Specification (NW73.10.15) sets the procurement framework for authorised service providers to meet our AMP 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 become 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 suppliers 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.

10.3 Contract delivery

We are transitioning away from a lowest conforming tender model to a Primary Service Delivery Partner (PSDP) contracting model. Connetics will undertake the role of the PSDP and will contract for services from other contracting companies to ensure that we can deliver on our AMP and maintain the resilience in our service providers.

The new contracting model will be operational by October 2021 and will position Orion to more effectively and efficiently meet the following outcomes:

- 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
- serve the Orion Group purpose of powering a cleaner and brighter future for our communities

This model will ensure a suitable platform to achieve future sustainability, continued investment in people, capability and competence and ensure that our service providers have a dedicated focus on health, safety, quality and the environment.

Our Procurement and Land Services team will maintain the contract and service level measures that are in place with Connetics.

Our Works Programming team are responsible for ensuring that our works are being delivered in a way that achieves long term value for our customers. They will do this by monitoring and approving pricing as well as the service levels being achieved. They are supported as appropriate by our operational and engineering teams.

Our Works Management information management system supports the above processes – including tenders, contracts, audit information and financial tracking.

10.3.1 Works programme

Our customer initiated projects are prioritised by our project prioritisation process, set out in Section 6. Our replacement and maintenance programmes are set out in Section 7.

10.3.2 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 AMP objectives. Our Procurement Policy outlines our strategic approach to procurement. Our key network risks and our proposed procurement 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 and 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 flexible contract options and conditions.

We aim to have fair and transparent procurement processes that are free from fraud and impropriety, and which are sustainable from economic, risk, legal, society, and environmental perspectives. We do this 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
- following good procurement practice
- continuous improvement
- ensuring sustainable value-add

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 staff to expediently deliver our AMP plan and objectives, including budgeted and unbudgeted expenditure. It also details authority limits for asset disposals, and research and development.

10.3.3 Tenders

Tenders are our preferred method of engagement for the supply of equipment and specialist services.

We assess tenders for equipment supply following a robust assessment of process using weighted attributes such as price, technical support, experience and reputation.

For the delivery of our planned and unplanned works we will utilise our Primary Service Delivery Partner (PSDP), Connetics, to plan and procure the delivery of work from Connetics or a number of other service providers through a dedicated arms-length Project Management Office (PMO).

The PMO will use a fair price methodology for assessing and awarding works and apply unit rates where work is repeatable.

We aim to maintain the relationships we have 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.

10.3.4 Resourcing

Our ability to deliver our AMP objectives relies on an appropriate level of competent, experienced and skilled resource – both within the Orion team, our PSDP and their service providers. The availability of sufficient and competent resources is essential to the delivery of our planned capital and operational expenditure, our response to customer initiated upgrades, and our ability to respond to network faults, emergencies and natural disasters.

We will proactively work with our PSDP to assess the levels of 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 resource that can be quickly redirected to areas of greater need following High Impact Low Probability events.

> **The availability of sufficient and competent resources is essential to the delivery of our planned capital and operational expenditure, our response to customer initiated upgrades, and our ability to respond to network faults, emergencies and natural disasters.**

Our Works General Requirements places certain overarching requirements on our service providers:

- work shall be carried out safely, time mannerly 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 requirements for urgent work – for example, due to weather events, network failure or safety reasons. In this document, we mandate and 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

Where economically justified, we plan our activities to incentivise our service providers to grow and maintain the delivery resources we need:

- internal resources – the Orion team and its structure are described in Section 8 of this AMP. Section 8 of this AMP also provides comprehensive overviews and the responsibilities of each business support area and how their capabilities help deliver our AMP objectives
- service providers – we manage our service provider resources by 'smoothing' 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

10.3.5 Delivery

We deliver our programme of scheduled and emergency works using our PDSP framework, our service providers, and our in-house team based in our Christchurch office.

Our infrastructure management team is responsible for works planning and delivery of our annual work plan, supported as appropriate by our other teams. They use our robust contract delivery processes to safely construct, maintain and renew our network to achieve our expected service levels. Our other in-house teams, as shown in Section 8 of this AMP, provide and administer the vital business and information support functions which enable the successful delivery of our works programme.

Our focus on continuous improvement means we are always looking for ways to refine and improve our delivery processes for the benefit of all stakeholders.

We provide a highly responsive service to our customers and community in terms of managing situations where our network capacity in localised areas may be constrained or compromised by other parties, and by providing the ability for customers to connect to our network, or alter their connection type or capacity, in a timely manner.

10.3.6 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 as per NW72.20.05 (Contract Performance).

Our key objective when monitoring contract performance is continuous improvement including:

- enhanced collaborative and positive relationships with 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

Our historic approach to contract delivery was a successful model for Orion for a number of years. However, the extraordinary time following the Canterbury earthquakes masked some issues with this model. Our focus has always been on continuous improvement, and our PSDP model will deliver long term value to our customers and our stakeholders.

10.3.7 Conclusions on our ability to deliver our forecast work programme

Historically we have been confident in our ability to deliver our forecast opex and capex programmes as detailed in our AMP.

The key reasons for this are:

- our plan is for a relatively smooth opex and capex spend over the next five to ten years – this provides certainty for our 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
- we have a partnership approach with service providers and by sharing our long term proposed works programme with them, they are able to plan ahead to resource to meet our needs
- we are continuing to invest in the capability of the Orion team

The impact of the global COVID-19 pandemic on supply chains, in particular manufacturing and shipping, and the possibility of further regional and/or national lockdowns means there is some emerging uncertainty that we have to manage and mitigate. Currently we are experiencing some delays in long lead time equipment, but these delays will not have a major impact on our 10 year programme. We continue to monitor the situation and assess the impact on our short to medium term programme and manage as appropriate.

We are aware other external factors could change the above conclusions. For example, other EDBs around New Zealand are starting to increase their own opex and capex and so this will cause a strain on available resource. The only sustainable resolution to this increased demand is to increase the supply of skilled people. As an EDB, our key risk management approach to this issue is to clearly signal our forecast work programme so that service providers have the certainty they need to continue to invest.

Through our Energy Academy initiative, we are also exploring options to increase wider industry training and competence development.

Connetics' base at Waterloo Business Park.

Appendices

Photo: Orion and Connetics team members reviewing infrastructure maps.

Contents

Appendix A Glossary of terms

ABI: Air Break Isolator, a pole mounted isolation switch. Usually manually operated.

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.

Alternating current (AC): 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.

Ampere (A): unit of electrical current flow, or rate of flow of electrons.

Bushing: an electrical component that insulates a high voltage conductor passing through a metal enclosure.

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.

Capacitance: the ability of a body to store an electrical charge.

CBRM (condition based risk management): CBRM is 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.

Circuit breaker (CB): 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.

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: the Commerce Act (Orion New Zealand Limited Customised Price-Quality Path Determination 2013) in effect for FY15 to FY19. This determination applies to Orion, and replaces all terms of the Orion DPP Determination as they apply to Orion.

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.

DIN: Deutsches Institut für Normung, the German Institute for Standardisation. Equipment manufactured to these standards is often called 'DIN Equipment'.

Distributed/embedded generation (DG): a privately owned generating station connected to our network.

Distribution substation: is either a building, a kiosk, an outdoor substation or pole substation taking its supply at 11kV and distributing at 400V

EA Technology Ltd: is an international consultancy based in the UK. They were appointed as peer reviewers to the Auckland CBD cable failure ministerial enquiry and subsequently engaged by us to review our 66kV cable network.

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.

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.

Grid exit point (GXP): a point where Orion's network is connected to Transpower's transmission network.

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.

High voltage (HV): 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.

kVA: the kVA, or Kilovolt-ampere, output rating designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.

Appendix A Glossary of terms continued

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.

Lifelines project: an engineering study into the effects of a natural disaster on Christchurch city undertaken in the mid 1990s.

Line circuit breaker (LCB): 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'.

Low voltage (LV): 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.

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.

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.

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.

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

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.

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 About our business
	5 About our network
	8 Supporting our business
3. Assets covered	5 About our network
	7 Managing our assets
4. Service levels	4 Customer experience
5. Network development plans	6 Planning our network
	9 Financial forecasting
	10 Our ability to deliver
6. Lifecycle asset management planning (maintenance and renewal)	7 Managing our assets
	9 Financial forecasting
	10 Our ability to deliver
7. Risk management	3 Managing risk
8. Evaluation of performance	2 About our business
	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								🟩		🟩					

Appendix D Specifications and standards (assets) continued

		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							🟩								

Appendix D Specifications and standards (assets) continued

		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								🟩							

Appendix D Specifications and standards (assets) continued

		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
Asset management reports	**Document ID**															
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 NZ Ltd – AMP planning period: 1 April 2021 – 31 March 2031

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 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	9,635	15,121	10,104	10,352	11,083	10,361	10,565	10,774	10,987	11,204	11,426
11	System growth	10,136	18,172	12,934	9,775	14,880	17,259	7,479	13,377	11,909	6,843	5,757
12	Asset replacement and renewal	28,026	25,468	30,971	30,766	30,833	34,376	39,310	38,259	36,769	31,966	31,863
13	Asset relocations	4,161	2,735	6,791	7,126	1,646	1,399	1,427	1,979	1,662	1,694	1,728
14	Reliability, safety and environment:											
15	Quality of supply	5,646	7,281	16,561	14,904	9,796	12,327	10,783	12,374	6,948	4,369	5,606
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	7,333	7,298	7,693	7,266	7,409	7,555	9,986	3,410	2,374	2,421	2,469
18	**Total reliability, safety and environment**	12,979	14,578	24,253	22,170	17,205	19,882	20,770	15,784	9,321	6,790	8,075
19	**Expenditure on network assets**	64,937	76,075	85,053	80,189	75,648	83,277	79,551	80,172	70,647	58,498	58,848
20	Expenditure on non-network assets	6,955	8,829	7,248	4,479	5,034	5,281	4,690	5,946	4,455	4,273	4,741
21	**Expenditure on assets**	71,892	84,904	92,301	84,668	80,682	88,558	84,241	86,118	75,102	62,771	63,589
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	4,047	2,900	5,606	5,808	1,887	1,790	1,826	2,213	1,984	2,023	2,063
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
27	**Capital expenditure forecast**	67,845	82,004	86,695	78,860	78,795	86,768	82,415	83,905	73,118	60,748	61,526
29	Assets commissioned	67,145	87,004	86,575	78,713	78,533	86,397	82,021	83,271	72,618	60,220	60,921
32		**$000 (in constant prices)**										
33	Consumer connection	9,635	15,121	9,973	10,040	10,541	9,664	9,664	9,664	9,664	9,664	9,664
34	System growth	10,136	18,172	12,766	9,481	14,154	16,098	6,841	12,000	10,475	5,903	4,869
35	Asset replacement and renewal	28,026	25,468	30,569	29,839	29,327	32,065	35,958	34,319	32,344	27,574	26,951
36	Asset relocations	4,161	2,735	6,702	6,911	1,566	1,305	1,305	1,775	1,462	1,462	1,462
37	Reliability, safety and environment:											
38	Quality of supply	5,646	7,281	16,346	14,455	9,318	11,499	9,864	11,100	6,112	3,769	4,742
39	Legislative and regulatory	-	-	-	-	-	-					
40	Other reliability, safety and environment	7,333	7,298	7,593	7,047	7,047	7,047	9,135	3,059	2,088	2,088	2,088
41	**Total reliability, safety and environment**	12,979	14,578	23,939	21,502	16,365	18,546	18,999	14,159	8,200	5,857	6,830
42	**Expenditure on network assets**	64,937	76,075	83,950	77,773	71,952	77,679	72,768	71,917	62,145	50,459	49,776
43	Expenditure on non-network assets	6,955	8,829	7,127	4,330	4,772	4,910	4,296	5,312	3,955	3,745	4,136
44	**Expenditure on assets**	71,892	84,904	91,077	82,103	76,724	82,589	77,064	77,229	66,100	54,204	53,912
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and DSM, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion	4,161	2,735	6,702	6,911	1,566	1,305	1,427	1,979	1,662	1,694	1,728
49	Research and development	585	856	839	1,096	1,075	1,316	1,290	1,517	1,487	-	-
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 NZ Ltd – AMP planning period: 1 April 2021 – 31 March 2031

51		Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52	For year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	131	312	541	697	901	1,109	1,322	1,540	1,761
55	System growth	-	-	168	295	727	1,160	638	1,377	1,433	940	887
56	Asset replacement and renewal	-	-	402	927	1,506	2,311	3,352	3,939	4,425	4,393	4,912
57	Asset relocations	-	-	88	215	80	94	122	204	200	233	266
58	Reliability, safety and environment:											
59	Quality of supply	-	-	215	449	479	829	919	1,274	836	600	864
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	100	219	362	508	851	351	286	333	381
62	**Total reliability, safety and environment**	-	-	314	668	841	1,337	1,771	1,625	1,122	933	1,245
63	**Expenditure on network assets**	-	-	1,103	2,417	3,696	5,598	6,783	8,255	8,503	8,038	9,072
64	Expenditure on non-network assets	-	-	121	149	262	371	394	634	500	528	605
65	**Expenditure on assets**	-	-	1,224	2,566	3,958	5,969	7,177	8,889	9,003	8,566	9,677
68	**11a(ii): Consumer Connection**											
69	*Consumer types defined by EDB (see note)*	**$000 (in constant prices)**										
70	General Connections	3,792	4,931	3,787	3,631	3,631	3,631					
71	Large Customers	1,332	4,775	1,403	1,716	2,217	1,340					
72	Subdivisions	2,098	2,706	2,074	1,984	1,984	1,984					
73	Switchgear	839	884	884	884	884	884					
74	Transformers	1,574	1,825	1,825	1,825	1,825	1,825					
76	**Consumer connection expenditure**	9,635	15,121	9,973	10,040	10,541	9,664					
77	*less* Capital contributions funding consumer connections	995	1,119	952	892	880	880					
78	**Consumer connection less capital contributions**	8,640	14,002	9,021	9,148	9,661	8,784					
79	**11a(iii): System Growth**											
80	Subtransmission	121	6,231	7,716	3,977	3,652	4,546					
81	Zone substations	7,037	9,873	2,143	1,537	6,534	7,586					
82	Distribution and LV lines	-	-	-	-	-	-					
83	Distribution and LV cables	2,025	1,591	494	313	313	313					
84	Distribution substations and transformers	-	-	-	-	-	-					
85	Distribution switchgear	-	-	253	-	-	-					
86	Other network assets	954	477	2,160	3,654	3,654	3,654					
87	**System growth expenditure**	10,136	18,172	12,766	9,481	14,154	16,098					
88	*less* Capital contributions funding system growth	-	-	-	-	-	-					
89	**System growth less capital contributions**	10,136	18,172	12,766	9,481	14,154	16,098					
90												

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 NZ Ltd – AMP planning period: 1 April 2021 – 31 March 2031

91		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
92	For year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
93	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
94	Subtransmission	954	940	1,399	1,117	1,154	1,180
95	Zone substations	8,128	6,262	6,755	6,348	5,069	4,889
96	Distribution and LV lines	5,394	6,358	7,058	9,042	9,575	11,589
97	Distribution and LV cables	711	746	804	595	595	595
98	Distribution substations and transformers	1,710	1,623	1,623	1,623	1,623	1,623
99	Distribution switchgear	5,348	6,047	8,310	8,550	9,010	9,490
100	Other network assets	5,781	3,492	4,620	2,563	2,302	2,699
101	**Asset replacement and renewal expenditure**	28,026	25,468	30,569	29,839	29,327	32,065
102	*less* Capital contributions funding asset replacement						
103	**Asset replacement and renewal less capital contributions**	28,026	25,468	30,569	29,839	29,327	32,065
107	**11a(v): Asset Relocations**						
108	*Project or programme*	**$000 (in constant prices)**					
109	NZTA	210	574	887	887	835	574
110	Christchurch City Council	700	960	1,169	1,169	261	261
111	Selwyn Disrtict Council	315	887	157	365	157	157
112	Developer / 3rd party	2,937	313	4,489	4,489	313	313
113	Ōtākaro	-	-	-	-	-	-
115	All other projects or programmes – asset relocations						
116	**Asset relocations expenditure**	4,161	2,735	6,702	6,911	1,566	1,305
117	*less* Capital contributions funding asset relocations	3,052	1,781	4,581	4,741	915	790
118	**Asset relocations less capital contributions**	1,109	954	2,121	2,170	651	515
122	**11a(vi): Quality of Supply**						
123	*Project or programme*	**$000 (in constant prices)**					
124	Coleridge reliability improvement	-	355	-	-	-	-
	Darfield reinforcement	-	-	713	-	-	-
	LV monitoring	585	856	839	1,096	1,075	1,316
	Northern Christchurch	514	5,929	7,356	-	-	-
	Region A 66kV resiliency	821	-	7,323	13,244	8,128	10,073
	Hawthornden tee-off	2,986	-	-	-	-	-
	Region B subtransmission	33	-	-	-	-	-
125	Comms associated with Entec line switches	110	115	115	115	115	110
126	Low voltage correction	-	26	-	-	-	-
127	Akaroa township	344	-	-	-	-	-
128	Rolleston security improvements	174	-	-	-	-	-
130	All other projects or programmes – quality of supply						
131	**Quality of supply expenditure**	79	7,281	16,346	14,455	9,318	11,499
132	*less* Capital contributions funding quality of supply		-	-	-	-	-
133	**Quality of supply less capital contributions**	5,646	7,281	16,346	14,455	9,318	11,499

Schedule 11a. Report on forecast capital expenditure continued

Company name: Orion NZ Ltd – AMP planning period: 1 April 2021 – 31 March 2031

135 136	For year ended	Current year 31 Mar 21	CY+1 31 Mar 22	CY+2 31 Mar 23	CY+3 31 Mar 24	CY+4 31 Mar 25	CY+5 31 Mar 26
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme*	**$000 (in constant prices)**					
139	N/A						
140							
141							
142							
143							
145	All other projects or programmes – legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme*	**$000 (in constant prices)**					
153	Papanui 11kV reconfiguration	-	-	295	-	-	-
154	LV ties replacement with Krone	252	251	251	-	-	-
155	Supply Fuse Relocation Programme	7,081	7,047	7,047	7,047	7,047	7,047
156							
157							
159	All other projects or programmes – reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	7,333	7,298	7,593	7,047	7,047	7,047
161	*less* Capital contributions funding reliability, safety		-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	7,333	7,298	7,593	7,047	7,047	7,047
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme*	**$000 (in constant prices)**					
169	Plant and vehicles	1,460	1,176	1,565	954	1,146	1,179
170	Information technology	4,330	6,230	4,815	2,668	2,917	2,996
171	Corporate land and buildings	442	789	290	291	292	293
172	Tools and equipment	723	634	457	417	417	442
173			-	-	-	-	-
175	All other projects or programmes – routine expenditure	-	-	-	-	-	-
176	**Routine expenditure**	6,955	8,829	7,127	4,330	4,772	4,910
177	**Atypical expenditure**						
178	*Project or programme*						
179	N/A						
180							
181							
182							
183							
185	All other projects – atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
188	**Expenditure on non-network assets**	6,955	8,829	7,127	4,330	4,772	4,910

Schedule 11b. Report on forecast operational expenditure continued

Company name: Orion NZ Ltd – AMP planning period: 1 April 2021 – 31 March 2031

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 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	7,922	8,200	8,335	8,515	8,706	8,902	9,103	9,308	9,518	9,733	9,953
11	Vegetation management	4,000	4,520	4,371	4,569	4,778	4,342	4,440	4,540	4,643	4,748	4,855
12	Routine and corrective maintenance and inspection	12,634	12,940	13,555	13,908	14,258	14,682	15,451	15,759	16,116	16,407	16,674
13	Asset replacement and renewal	2,465	2,475	1,870	1,485	839	1,042	1,066	1,078	1,167	1,193	1,220
14	**Network Opex**	27,021	28,135	28,132	28,477	28,581	28,969	30,059	30,686	31,443	32,080	32,702
15	System operations and network support	18,962	17,695	17,732	18,370	19,049	19,120	19,895	20,386	21,351	22,419	22,995
16	Business support	17,573	19,819	19,763	20,120	20,494	20,953	21,452	21,909	22,419	22,987	23,458
17	**Non-network opex**	36,535	37,514	37,495	38,490	39,543	40,073	41,347	42,295	43,770	45,406	46,453
18	**Operational expenditure**	63,556	65,649	65,627	66,967	68,124	69,042	71,406	72,981	75,213	77,486	79,155
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	7,922	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
23	Vegetation management	4,000	4,520	4,300	4,400	4,500	4,000	4,000	4,000	4,000	4,000	4,000
24	Routine and corrective maintenance and inspection	12,634	12,940	13,335	13,395	13,430	13,525	13,920	13,885	13,890	13,825	13,795
25	Asset replacement and renewal	2,465	2,475	1,840	1,430	790	960	960	950	1,005	1,005	1,005
26	**Network opex**	27,021	28,135	27,675	27,425	26,920	26,685	27,080	27,035	27,095	27,030	27,000
27	System operations and network support	18,962	17,695	17,419	17,637	17,864	17,504	17,796	17,820	18,210	18,696	18,734
28	Business support	17,573	19,819	19,543	19,597	19,607	19,709	19,842	19,918	20,017	20,187	20,244
29	**Non-network opex**	36,535	37,514	36,962	37,234	37,471	37,213	37,638	37,738	38,227	38,883	38,978
30	**Operational expenditure**	63,556	65,649	64,637	64,659	64,391	63,898	64,718	64,773	65,322	65,913	65,978
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and DMS, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Insurance	2,245	2,569	2,641	2,735	2,832	2,932	3,035	3,141	3,250	3,362	3,477
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	135	315	506	702	903	1,108	1,318	1,533	1,753
43	Vegetation management	-	-	71	169	278	342	440	540	643	748	855
44	Routine and corrective maintenance and inspection	-	-	220	513	828	1,157	1,531	1,874	2,226	2,582	2,879
45	Asset replacement and renewal	-	-	30	55	49	82	106	128	162	188	215
46	**Network Opex**	-	-	457	1,052	1,661	2,284	2,979	3,651	4,348	5,050	5,702
47	System operations and network support	-	-	313	733	1,185	1,616	2,099	2,566	3,141	3,723	4,261
48	Business support	-	-	220	523	887	1,244	1,610	1,991	2,402	2,800	3,214
49	**Non-network opex**	-	-	533	1,256	2,072	2,860	3,709	4,557	5,543	6,523	7,475
50	**Operational expenditure**	-	-	990	2,308	3,733	5,144	6,688	8,208	9,891	11,573	13,177

Schedule 12a Report on asset condition

7					Asset condition at start of planning period (percentage of units by grade)							
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%	1%	15%	39%	45%	-	3	1%
11	All	Overhead Line	Wood poles	No.	2%	5%	23%	15%	56%	-	3	12%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	12%	47%	40%	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	100%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	13%	86%	1%	-	3	13%
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	-	-	-	11%	89%	-	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.	-	1%	9%	56%	34%		3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100%	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	4%	43%	46%	7%	-	3	21%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	40%	5%	55%	-	3	17%
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.	-	-	8%	3%	89%	-	4	6%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	29%	5%	66%	-	4	19%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	

Schedule 12a Report on asset condition continued

36					Asset condition at start of planning period (percentage of units by grade)							
37 38	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	1%	11%	43%	45%	-	3	4%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	7%	37%	56%	-	3	9%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	-	-	12%	24%	64%	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	0%	1%	99%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	18%	51%	30%	1%	3	-
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.	1%	3%	10%	46%	40%	-	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	53%	11%	36%	-	4	24%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1%	3%	9%	53%	34%	0%	2	5%
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.	-	0%	30%	17%	52%	1%	4	10%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	1%	13%	23%	63%	-	3	7%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	23%	21%	56%		3	5%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	27%	-	73%		3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0%	1%	16%	45%	38%		3	1%
55	LV	LV Line	LV OH Conductor	km	-	0%	8%	61%	30%	0%	3	-
56	LV	LV Cable	LV UG Cable	km	-	-	0%	13%	87%	0%	3	0%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km						100%	1	-
58	LV	Connections	OH/UG consumer service connections	No.			5%	85%	10%		1	6%
59	All	Protection	Protection relays (electromechanical, solid state)	No.	-	-	19%	21%	60%		3	27%
60	All	SCADA and communications	SCADA and comms equipment operating as a single system	Lot	-	12%	27%	28%	33%	0%	3	64%
61	All	Capacitor Banks	Capacitors including controls	No.					100%		2	-
62	All	Load Control	Centralised plant	Lot	-	-	11%	68%	20%		3	3%
63	All	Load Control	Relays	No.						100%	1	-
64	All	Civils	Cable Tunnels	km					100%		3	-

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	16	30	N-1	16	54%	30	63%	No constraint within +5 years	
10	Addington 11kV #2	19	30	N-1	19	63%	30	64%	No constraint within +5 years	
11	Armagh	17	40	N-1	17	43%	40	53%	No constraint within +5 years	Central City Rebuild expected to give large load increase over next few years
12	Barnett Park	8	15	N	8	55%	15	56%	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	Bromley	30	60	N-1	30	50%	60	52%	No constraint within +5 years	
14	Dallington	27	40	N-1	27	69%	40	70%	No constraint within +5 years	
15	Fendalton	35	40	N-1	35	87%	40	86%	No constraint within +5 years	
16	Halswell	20	23	N-1	20	87%	23	94%	No constraint within +5 years	Install 3rd transformer when needed
17	Hawthornden	31	40	N-1	31	78%	40	81%	No constraint within +5 years	
18	Heathcote	22	40	N-1	22	56%	40	58%	No constraint within +5 years	
19	Hoon Hay	32	40	N-1	32	79%	40	74%	No constraint within +5 years	
20	Hornby	16	20	N-1	16	80%	20	85%	No constraint within +5 years	
21	Ilam	7	11	N-1	7	66%	11	69%	No constraint within +5 years	
22	Lancaster	19	40	N-1	19	48%	40	50%	No constraint within +5 years	
23	McFaddens	34	40	N-1	34	84%	40	86%	No constraint within +5 years	
24	Middleton	26	40	N-1	26	66%	40	70%	No constraint within +5 years	
25	Milton	35	40	N-1	35	87%	40	96%	No constraint within +5 years	Load transfer to Addington when needed
26	Moffett	14	23	N-1	14	59%	23	71%	No constraint within +5 years	
27	Oxford Tuam	12	40	N-1	12	31%	40	39%	No constraint within +5 years	
28	Papanui	36	48	N-1	36	74%	48	86%	Other	Install new Belfast zone substation to alleviate 11kV constraint which also avoids emerging transformer constraint
29	Prebbleton	7	15	N	7	47%	15	49%	No constraint within +5 years	
30	Rawhiti	27	40	N-1	27	67%	40	67%	No constraint within +5 years	
31	Shands	13	20	N-1	13	66%	20	88%	No constraint within +5 years	
32	Sockburn	22	29	N-1	22	77%	29	81%	No constraint within +5 years	
33	Waimakariri	23	40	N-1	23	57%	40	58%	No constraint within +5 years	
34	Annat	4	-	N	3	-	-	-	No constraint within +5 years	
35	Bankside	6	-	N	4	-	-	-	No constraint within +5 years	
36	Brookside 66kV	9	-	N	6	-	-	-	No constraint within +5 years	
37	Darfield	6	-	N	4	-	-	-	No constraint within +5 years	
38	Diamond Harbour	2	-	N	2	-	-	-	No constraint within +5 years	
39	Dunsandel	17	23	N-1	12	74%	23	74%	No constraint within +5 years	
40	Duvauchelle	4	8	N-1	4	57%	8	56%	No constraint within +5 years	
41	Greendale	6	-	N	5	-	-	-	No constraint within +5 years	
42	Highfield	9	-	N	6	-	-	-	No constraint within +5 years	
43	Hills	7	-	N	5	-	-	-	No constraint within +5 years	
44	Hororata	9	-	N	6	-	-	-	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
45	Killinchy	9	-	N	6	-	-	-	No constraint within +5 years	
46	Kimberley	15	23	N-1	10	63%	23	63%	No constraint within +5 years	
47	Larcomb	14	23	N-1	10	61%	23	75%	No constraint within +5 years	
48	Lincoln	10	10	N-1	7	105%	10	115%	Transformer	Constraint to be resolved by transfers to Springston zone substation
49	Little River	1	-	N	1	-	-	-	No constraint within +5 years	
50	Motukarara	4	8	N-1	4	47%	8	47%	No constraint within +5 years	
51	Rolleston	12	10	N-1	8	117%	10	107%	Transformer	Constraint to be resolved by transfers to Weedons & Highfield
52	Springston 66/11kV	7	-	N	5	-	10	114%	No constraint within +5 years	Staged upgrade to 2 x 10MVA transformers
53	Te Pirita	7	-	N	5	-	-	-	No constraint within +5 years	
54	Weedons	12	23	N-1	8	52%	23	63%	No constraint within +5 years	

Schedule 12c Report on forecast network demand

		Number of connections					
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by* consumer type						
9		*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	For year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
11	*Consumer types defined by EDB**						
12	Streetlighting	33	25	25	25	25	25
13	General	5,425	5,045	3,345	2,845	2,845	2,845
14	Irrigation	4	10	10	10	10	10
15	Major Customer	8	20	20	20	20	20
16	Large Capacity	-	-	-	-	-	-
17	**Connections total**	5,470	5,100	3,400	2,900	2,900	2,900
18							
19	**Distributed generation**						
20	Number of connections	520	560	560	560	560	560
21	Capacity of distributed generation installed in year (MVA)	6	7	7	7	7	7
22	**12c(ii) System Demand**						
23							
24	**Maximum coincident system demand (MW)**						
25	GXP demand	623	621	634	642	653	660
26	*plus* Distributed generation output at HV and above	1	1	1	1	1	1
27	**Maximum coincident system demand**	624	622	635	643	655	661
28	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	624	622	635	643	655	661
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	3,443	3,478	3,513	3,548	3,583	3,619
32	*less* Electricity exports to GXPs	-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation	11	11	12	13	14	15
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**	3,454	3,489	3,525	3,561	3,597	3,634
36	*less* Total energy delivered to ICPs	3,312	3,346	3,380	3,415	3,450	3,486
37	**Losses**	142	143	145	146	147	148
38							
39	**Load factor**	63%	64%	63%	63%	63%	63%
40	**Loss ratio**	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%

Schedule 12d Report forecast interruptions and duration

8		*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	For year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
10	**SAIDI**						
11	Class B (planned interruptions on the network)	9.4	9.8	10.1	10.5	10.9	10.9
12	Class C (unplanned interruptions on the network)	67.6	70.0	69.0	69.0	69.0	69.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.04	0.04	0.04	0.04	0.04	0.04
15	Class C (unplanned interruptions on the network)	0.83	0.83	0.83	0.82	0.82	0.82

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	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 2019 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. The AM Policy has not been modified in the last 12 months and is still published within the 2019 AMP.	Widely used asset management practice standards require an organisation to document, authorise and communicate its asset management policy (e.g., as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3.75	The Orion NZ Asset Management Strategy is imbedded within the AMP 2019 document in section 2.8. Orion's Asset Management Strategy has six stated focus areas: 1. Listening to our customers 2. Continuous improvement to ensure a safe, reliable and resilient network and operations 3. Being committed to continuous improvement in health and safety 4. Minimising our impact on the environment 5. Continually developing our capability as effective asset managers 6. Enabling our customers to take advantage of future technologies The AM Strategy has not been modified in the last 12 months and is still published within the 2019 AMP.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (e.g., as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.

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. Whilst the policy has not changed, the asset management practise within the policy has been updated (see below) and shows greater engagement.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The asset management policy, cautious approach to risk and clear understanding of why Orion was using its assets in this manner were spread well through the organisation and its contractors.
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. Specific asset management practises (i.e. Reporting & capturing suspect poles) are well understood by the staff running the process. Recent changes to structure and staffing levels reflect the importance placed on these linkages.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. Some processes are functional but are not documented formally.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Documented info
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?	3.75	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	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management.	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3.75	The 2019 AMP sets out Orion's asset management policy, strategy, practices and expenditure forecasts for the next 10 years from 1 April 2019. This current 372 page document has been substantially updated from the last AMP and is of very high quality. The current AMP is a condensed 78-page 2020 AMP Update which covers the Orion NZ updated strategy, practices, programme of work and expenditure forecasts for the next 10 years from 1 April 2020 to 31 March 2030. The 2020 AMP Update is to be read in conjunction with the previous more detailed 2019 AMP.	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?	3.75	The current 2020 AMP Update which covers the Orion NZ updated strategy, practices, programme of work and expenditure forecasts for the next 10 years from 1 April 2020 to 31 March 2030. The 2020 AMP Update is to be read in conjunction with the previous more detailed 2019 AMP. Both AMP's are 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?	3.75	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.

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
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. Asset management strategy is evident in the discussions and decision-making process. It was clearly articulated and there was understanding "around the table."	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The Strategic Asset Management documentation is articulated and well understood, but not full documented.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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. Orion AMP is published and available via Web. The AMP is used for capital projects and planning. Business Case submissions to the Board revolve around the AMP	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. Broad circulation of capital projects/operations.
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. Yes and delegations documented.	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	Documented info
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)	3.75	The condensed version of the 2020 AMP Update has enable a more cost effective review process, which has focused on upcoming and future asset improvement areas.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	4	" 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	"The following aspects of Structure and Leadership have been noted this year. Growth of the team structure Clarity of roles and learnings being embedded – i.e. on poles. Garry Heyes – Procurement & Property Services Manager Network Infrastructure, now settling into his new role and using his past experience to drive improvement within his portfolio. Alasdair Reid – Engineering Manager is now spreading his influence, both in an engineering and a asset management focus. New people in key roles where gaps were previously noted, or inputs required Increased leadership involvement in industry wide initiatives.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets e.g., para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.

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
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. Orion have documented the changed organisation structure, their function and Job Description, along with their delegated authority.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	"Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place. Disaster response plans are in place and are comprehensive. Active progress on security of stores has been evidenced."	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. With learnings from the earthquakes, Orion has implemented a new IL 4 building which houses the staff and control room, along with a second containerised control room with associated generation to ensure a hot switch with zero delay in the event of a disaster. Mechanisms and operations are in place for this change, and are tested regularly - next scheduled IS/IT test October 2018"
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. Appointed staff have a job description and delegation with a clear understanding of what they are doing. Whilst not everyone articulated their purpose in terms of the asset management strategy and plan, none communicated process or actions that did not support them."	"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	Documented info
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	"Orion NZ ensures staff are made aware of the current Asset Management Framework by talking at meetings, presenting to staff at all staff sessions, AMP 101 sessions and also "lunch and learns" sessions. Their core contractors have also had the AMP shared with them as well as an understanding of how to read it.	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 year it is noted that more members of the Orion NZ Senior Leadership Team (SLT) have increased their awareness and activity in asset management improvement and awareness activities. 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 (e.g., PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-about would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	4	Orion NZ 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 NZ is striving to achieve	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (e.g., PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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
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. Management was in the process of changing resources to meet the changed demands of the regions development. New structures were in place and financial delegations updated (but planned for review in the near future for escalation.)"	"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. Clear understanding across various departments and levels on asset management approach and criteria."	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	"The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	"Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system. Orion are the first responder, but all field works are undertaken by pre-qualified and assessed contractors via a controlled access process."	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. There was some evidence that the contractors understood Orion's asset management focus, but mostly an understanding of how they had to comply with Orion's technical specification, maintenance, assessments and works via the competency assessment and access controls."

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Documented info
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 NZ is assisting core contractor organisations to development entry level staff in roles aligned with Orion NZ's asset management improvement initiatives. During our discussion with Orion NZ, WSP were given a presentation on a new initiative which Orion NZ and Connectics are developing together. A Training Academy Presentation was delivered to WSP. It is hoped that this new training initiative pilot will lead to other EDB's joining in and developing this industry specific training programme. This is a training area that does not exist currently for EDB's and both organisations have taken this leadership role to ensure core industry training options can be developed for the future.	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?	3.75	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 NZ's PowerOn application, while competency management processes are carefully documented.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (e.g., PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3.75	"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 NZ'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.

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
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). Staff training was clearly demonstrated and EAC/PHC were tracked and recorded, both for staff and approved contractors with substation/asset access."	"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. Competency against job descriptions are recorded and reviewed along with delegations when promotions or re-organisations are undertaken,"	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	"Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements. Competency against job descriptions are recorded and reviewed along with delegations when promotions or re-organisations are undertaken."	"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	Documented info
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?	3.5	"Powerful Future" has also been shared to seek opinion and input from staff. As part of this, members of the leadership team are presenting the asset management plan. This has been supplemented with a quarterly contract review meeting with contractors providing an interactive session for feedback.	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 NZ have made significant improvements and updates to many of their asset related document e.g. 18 Asset Management Reports, on various asset topic were updated in the past 12 months.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (i.e., the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (e.g., s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3.25	The AMP details the broad range of information and applications in place to support Orion NZ'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 NZ have in the past, chosen "best of breed" (as opposed to an integrated system) and this is considered appropriate for this organisation as it has been well integrated. However due to data governance improvement requirements, new technology will be required in the future.	"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.

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
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. Clear evidence of communications and understanding"	"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. Very active documentation and drive to document and review"	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The asset management policy is well recorded and documented - it is being actively reviewed and revised to suit the changing needs of the region and stakeholders. This was pro-active in approach and not left to lag."
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. Documented and available - A clear concise summary would be very useful."	"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	Documented info
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?	3.25	Orion NZ's aim is to seamlessly gather, store and package specifically requested field findings in their Asset Register from various asset and maintenance inspections. Basix offers this additional functionality and whilst currently under development, progress is being made towards autonomously storing data and photographs from the field to enable the packaging of specific works based on priority, location and asset type. The potential for greater visibility and reporting capability is a significant driver towards the success of this initiative.	"The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (e.g., s 4.4.6 (a), (c) and (d) of PAS 55)."	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3.25	"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."	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?	3.5	"In the past Orion NZ has engaged a consultant to develop 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 continues to be developed. The CBRM model is one of the tools used to inform our 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 (e.g., para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/ or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/ or procedure(s) as a result of incident investigation(s). Risk registers and assessments.

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
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 IS system is secure and well backed-up. GIS and BASIX were active and appeared accurate on the specific assets we sampled."	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. No integrated management system, but the level of IS/IT was very appropriate for the size of Orion's organisation"
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. Users were enthusiastic about the system and the fact that their feedback was taken into consideration."	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. Feedback was received and incorporated into the change of various key reports, such as suspect pole reports, to ensure better information was received. Disposed assets information was retained and was searchable so that past trends could be reviewed against current issues."
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. Risk management was clearly articulated from all aspects, including technical, operational, sub-contracts and financial/administrative and procurement."	"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	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?	4	Orion is looking at improvement opportunities to improve workflow processes to ensure consistency across the business.	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?	4	"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 (e.g., PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives
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 NZ 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. 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 (18 of these AMR documents were updated in the past year).	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (e.g., PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3.5	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.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (e.g., as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.

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. Clear thought had been given to the risk process in related fields such as procurement and how this responded to legal and easement/access/maintenance and subsequent operational safety and reliability."
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. Complied"	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. Orin reviewed their compliance in detail, including giving clear responsibility to one person in each key department who advised the Board on their obligations and potential impacts (not just financial or PR risk.)"
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. Orion are actively reviewing asset operational life with respect to their environment. They have reviewed defects and unplanned outages with respect to age of asset and are clearly aware of the issues."	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. Have started down the path of correlation of trends against previous decisions/designs and are beginning to modify the process accordingly. We would expect this to be a 3.5 or 4 at next assessment"
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. Industry and process are mature against the regions background of upheaval and now steady state growth."	"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	Documented info
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3.5	Project works and maintenance activities continue to be closely managed by Orion staff to ensure agreed standards are maintained. Orion NZ have recently 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.	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?	3.5	"Major failures and incidents are investigated on a case by case basis and escalated to senior management for review. 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 customers. 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))?	3.5	"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 (e.g., the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.

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. This was met but not yet exceeded, although pockets of excellence were in evidence"	"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. Yes and currently under review to match the new structure. This is a positive mark of an active 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."
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. There is evidence of sufficient internal checking (such as authorising beyond the financial limits specified) but this is not embedded in the system and relies on another internal person to pick this up. Whilst documents indicate a review procedure and some meetings have a review function, this is frequently carried out in an informal manner. In many ways this is appropriate to the organisation size/culture but could be difficult to transfer."	"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	Documented info
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
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?	3.5	"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?	3.5	Orion NZ 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.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (e.g., by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

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
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. Active PM and CM process which has been effectively used to detect unplanned outage trends."	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. No planned maintenance system per se – everything is run on a calendar system and not tracked on hours run/load levels or switching cycles – although some of these factors are taken into account."
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. CI is active"	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. Orion operate sin a conservative industry and their operation of assets within definite tolerances reflects this (Not sweating assets) but they are improving through the changes of process and procedure."
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. Staff are frequently sent to various asset management seminars with engagement with EEA, EA and CIGRE. This is very similar to other lines companies who are acutely aware of ComCom focus on AMMAT."	"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 2022

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 FY22 to FY31 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 FY24, extrapolated by PwC to FY31
- non-network labour – NZIER forecasts to FY24, extrapolated by PwC to FY31
- other – NZIER producer price index (PPI) forecasts to FY25, extrapolated by PwC to FY31.

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, Jane Taylor and Bruce Gemmell, 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. 3. 2021 Date
Director	19. 3. 2021 Date

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