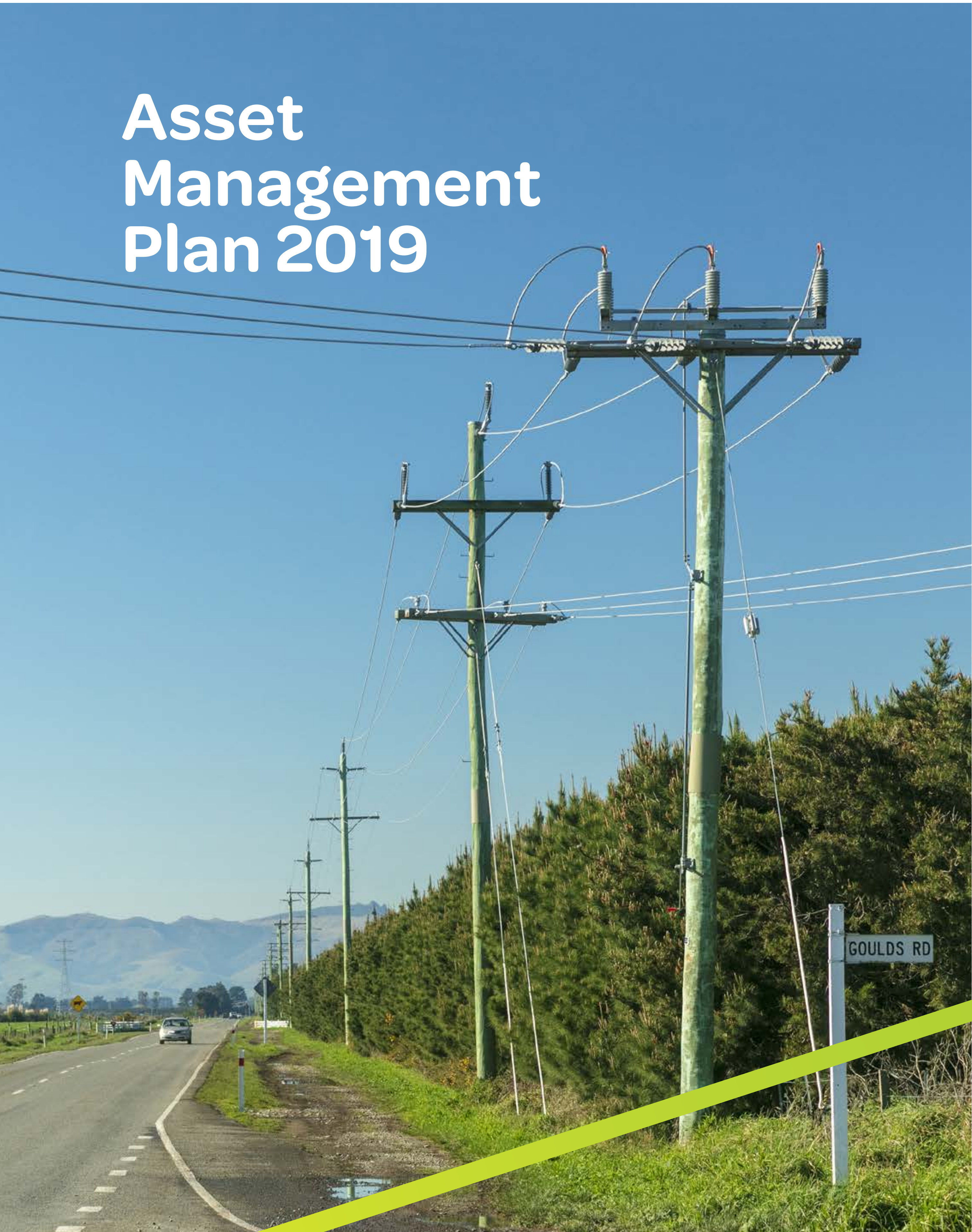
Orion New Zealand Limited
Asset Management Plan

Asset Management Plan 2019



Cover: This line of Orion poles sits at the corner of Ellesmere Junction Road and Gould Road in Springston, and was replaced and upgraded in 2016. For details of Orion's pole maintenance and replacement programme, see Section 7.

Orion’s Asset Management Plan outlines our commitment to powering the future electricity needs of every person, business, and organisation in the Central Canterbury region.

At its heart, this plan reflects our pledge to provide a reliable, resilient and safe electricity service to our more than 200,000 customers. It also fulfils our obligation to be a responsible steward of more than $1b of Orion assets owned by the community they serve.

In 2018 we completed our seven year earthquake recovery programme a year ahead of schedule. It is now time for us to look forward to how we play our part in this vibrant, exciting region. It’s also a pivotal time, with many looking to New Zealand’s 85% renewable electricity to help solve their carbon challenges; from transport to industrial processing. That necessarily places our quality energy platform at the very heart of our region.

This plan outlines how we will invest to maintain, grow and transform our network over the next 10 years. It is the start of an exciting new era as we help deliver sustainable, reliable and affordable solutions to our region’s energy and environmental needs.

Rob Jamieson
Chief Executive

Orion

Liability disclaimer

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

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

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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.

Contents

Contents continued

Figures

Figures continued

Tables

Tables continued

Tables continued

1 Executive summary

Photo: Orion rural Network Operator, Tony Smith, talks with local Springston dairy farmer. Tony is a member of our Field Response team of 18 who provide swift, on the spot investigation of network and customer faults, undertake emergency repairs and make the network safe for emergency services.

Introducing our 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 2019.

This plan is informed by Orion's Statement of Intent (SOI), by our Business Plan, our Business Strategy and our Vision and Values. This AMP is a realistic blueprint to deliver on our commitment to our customers and help us to remain one of the most reliable, resilient and efficient electricity networks in New Zealand.

We share who we are, what risks we face in managing our assets, what our customers are telling us, the condition of our assets and our distribution system, how we plan to care for and enhance them, and how we support the delivery of this. Our plans are discussed over a 10 year period from April 2019 until March 2029.

Orion provides an essential service, electricity, to a customer base of more than 200,000 Canterbury people living between the Waimakariri and Rakaia Rivers. Our customers use electricity to power their homes and run their businesses to provide services and produce products for the wider community.

At the heart of what we do is our desire to continue to deliver a safe, reliable and resilient electricity delivery at service levels and a cost that our customers feel is fair and reasonable. Increasingly we are seeing change in our industry and in customer expectations. As well as providing a service that is safe, reliable and resilient, we will also need to adapt our network so that it is flexible to meet changing customer needs and choices.

Our asset management programme is driven by our Business Strategy, our Asset Management Policy and our Asset Management Strategy. It is implemented through a rigorous process informed by data and analysis.

Our Asset Management Strategy has six focus areas:

- Listening to our customers
- Continuous improvement to ensure a safe, reliable and resilient network and operations
- Being committed to continuous improvement in health and safety
- Minimising our impact on the environment
- Continually developing our capability as effective asset managers
- Enabling our customers to take advantage of future technologies

Over the next ten years we are forecasting total capital expenditure of $730m and operational expenditure of $677m. We plan to apply expenditure wisely, and provide our customers with genuine value for that money.

Where we've come from

It is now more than eight years since the Canterbury earthquakes and 2019 marks a turning point for Orion. From 2010 through to 2018 our attention was appropriately focussed on our region's recovery. In 2018 we completed our earthquake recovery programme, a year ahead of schedule.

We are proud of the way our people and network stood up to the challenges the earthquakes presented. Our strong history of focus on safety, reliability and resilience paid significant dividends and was key in contributing to our community's recovery.

New technologies, such as electric vehicles, batteries and solar power, have become part of our conversation and planning.

In that time there have been significant changes. Our region and city's geographical footprint has moved west and north, as our population grew and we abandoned the Christchurch residential red zones. With this has come development and growth across all categories of customer - residential, commercial and industrial. In addition, new technologies, such as electric vehicles, batteries and solar power, have become part of our conversation and planning.

Looking to the future

While this has been an exceptional time in our region and our country's recent history, our attention is now firmly on the future. We approach the next ten years from a solid foundation, with a network that is revitalised and resilient. We believe it is critical our historical focus on safety, reliability and resilience is not diminished and our investment in Orion's network and people continues to ensure we are well prepared for future challenges.

We approach the next ten years from a solid foundation, with a network that is revitalised and resilient.

Our legacy of innovating, proportionate risk management, adopting new technologies and asset management techniques along with a sustained focus on customer expectation and service will continue.

The need for continued investment

Orion's network needs to constantly evolve to respond to a changing environment and customer needs. Ongoing investment is critical and we strive to do this prudently and efficiently. We are thoughtful about the investments we make and how that impacts what our customers pay for our service. To find out what our customers expect of us, and where they want us to invest to support their vision for the future, we use a range of different methods of engagement.

These methods include 1:1 conversations, focus groups, customer workshops, telephone and on-line surveys and our Customer Advisory Panel.

To find out what our customers expect of us, and where they want us to invest to support their vision for the future, we use a range of different methods of engagement.

From a network development perspective many of our recent key projects in urban areas have been focused on shoring up our network's resilience. In our rural area we have seen significant customer growth and we have invested in new network assets to meet this. Undertaking major projects to address key customer needs for resilience and support growth are critical. We also need to ensure we maintain our network through robust asset lifecycle approaches and have dedicated more than $650m of combined operational and capital replacement expenditure to maintain our existing assets over the 10 year period of this plan.

Typically, network development requires significant investment and is undertaken in large stand-alone projects. Our choice of projects to undertake is informed by the needs of our customers and includes consideration of:

- Our "security of supply" standard – that is the levels of reliability and resilience we are looking to achieve
- Network utilisation
- Safety
- Growth or decline in demand

We consider different options to address the particular issue we face, which may include traditional network build or other options such as demand management or distributed generation. Once we have established the way forward we undertake a project prioritisation process to manage our programme of work. This is complex and involves weighing up multiple factors, including:

- Safety and urgency
- Customer needs, like reliability or specific connection upgrades or requirements
- Asset health, condition, criticality and maintenance needs
- Type of driver i.e. resilience, replacement, renewal, obsolescence etc
- Resource and seasonal timing of work
- Other works

Our performance is not delivered solely by our management of network assets but also by our attention to customer service, process improvements, people capability, and information management. Innovations and efficiencies in these areas also support overall outcomes for customers.

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Our obligation to be a responsible steward of more than $1b assets, ultimately owned by the community they serve, is front of mind. This year's plan sets a new direction for us for the next 10 years at a time when our region is experiencing sustained growth, customers are looking for choice and communities seek to decarbonise their energy consumption. It is driven by three factors that are pivotal to our industry, customers and our regional context:

- Growth
- Resilience, reliability and safety – particularly in the face of a predicted Alpine Fault earthquake in the next 50 years
- New technology

Our obligation to be a responsible steward of more than $1b assets, ultimately owned by the community they serve, is front of mind.

Growth

Our network is an essential partner in supporting the regeneration and growth of our region. Throughout our thinking about where we need to focus our investment runs a common theme: what's required to serve the unique needs of our region?

We have experienced recent unprecedented regional growth during a sustained period of increased building development and new customer connections. This means that in some areas our network capacity is at the upper levels of our security of supply standards. In response to that imperative, we have included plans to meet growing network demand, make upgrades to existing infrastructure, and provision work to power new businesses. These include:

- Investment to increase capacity in Belfast ($37.9m) to service existing customers, meet signalled industrial development, and residential growth in surrounding areas that has arisen and will continue as a result of significant investment by NZ Transport Agency in new road networks that strengthen direct links to the Christchurch Central Business District
- Investment to increase capacity and security of supply in the Selwyn District at a new Norwood GXP with subtransmission integration ($28.9m) to address rural township development in conjunction with commercial growth and signalled decarbonisation measures by cornerstone industrial customers

Our network is an essential partner in supporting the regeneration and growth of our region.

Reliability and Resilience and Safety

We are ever mindful of the need to maintain our existing assets. Our customers and the community depend on our service and we are focussed on providing a network that is reliable, resilient and safe. Orion's planning must incorporate preparation for our resilience in the face of significant high impact low probability events, such as an Alpine Fault earthquake, which has an estimated 30% chance of occurring in the next 50 years. We also take into account the impact on our reliability from day to day issues such as advancing asset age, vegetation and customer demand. Safety fundamentally underpins all we do. It is expressly included in our Asset Management Policy and Asset Management Strategy as one of the core principles that guide our investment and operational decisions.

We are ever mindful of the need to maintain our existing assets.

Our decisions about the quantity, timing and rate of asset replacement are informed by our diligent approach to risk management. Based on a whole of life assessment, we use condition based risk management of our existing assets which encompasses asset health, failure mode analysis and asset criticality. Managing our extensive asset fleet requires quality data to enable a robust understanding of asset condition, the environment assets operate in, who and how many customers they serve, and the relationship between these elements to support our decision making.

We use condition based risk management of our existing assets which encompasses asset health, failure mode analysis and asset criticality.

We pay close attention to our outage statistics to determine trends and patterns in asset behaviour and their contribution to outages. And we underpin our lifecycle management with on-going inspection, testing and monitoring regimes.

Our customers tell us they want us to maintain current levels of reliability, invest in resilience, and operate a safe network. To deliver on those expectations, our key areas of future investment, particularly for our poles, switchgear and cable assets, include:

- **Overhead lines** – overhead asset faults have the largest negative impact to our SAIDI/SAIFI performance. These assets can also pose a risk to public safety in the event of pole or conductor failure. To maintain our service levels we are planning to increase our pole replacement rate and maintain our overhead switchgear replacement plans. We will also continue our vegetation management programme. We have budgeted to spend $101m over the next 10 years on pole and conductor replacement to meet our reliability standard and ensure our network remains safe.
- **Circuit breakers and switchgear** – when switchgear fails the consequences can be significant. This can range from lengthy interruptions to our customers causing financial losses, to explosive failures that compromise the safety of our workers. We are continuing the replacement of our switchgear prioritising the poorest condition and critical sites first. We have budgeted to spend $90m on replacing aging circuit breakers and switchgear, including the introduction of automation, to ensure reliability and safety is not compromised.
- **Low voltage cables** – we have a programme to reduce risks associated with a historical practice where some LV supply fuses were installed in the customer meter box. This supply fuse relocation programme, which relocates the fuse to a distribution box on the property boundary is scheduled for completion in FY28. Our projected spend of $61m on this programme is dedicated to installing distribution boxes complete with fusing on the customer supply will provide better safety outcomes.
- **Subtransmission cables** – our 66kV oil filled cable joints are at risk of multiple failures in the event of the Alpine Fault rupturing. Joint failures could also cause the oil to spill into the environment. A lack of specialist skills would likely result in a lengthy repair time. We are currently reviewing our options for replacement and have allowed an expenditure of $24.7m towards the end of the plan to address this issue and improve the resilience of our network.

Preparing for a future of dynamic change, we are gearing up for new technology that is creating greater choice and opportunities for our customers.

New technology

Preparing for a future of dynamic change, we are gearing up for new technology that is creating greater choice and opportunities for our customers. Our customers are showing increasing interest in electric vehicles, generation and energy storage. Since 2013 we have seen a steady increase in solar connections. So far more than 2,500 of Orion's customers have installed solar generation with a small number incorporating battery storage. At present around 2,000 electric vehicles are operating in the Canterbury region and this is projected to significantly grow as global decarbonisation efforts increase, and vehicle prices are projected to come down.

The paradigm for electricity networks is changing from solely supplying energy in a one-way flow, to providing a two way platform for energy transfer.

To guide Orion's first steps in helping our customers take advantage of new technology and support our service delivery we will initiate a programme of targeted investment ($10m) to monitor our low voltage network. This will give us greater visibility of the effect of changing use on our low voltage system. As we see changing use impacting on the quality of our service we can anticipate the need for investment interventions at the right time.

Capital and operating expenditure

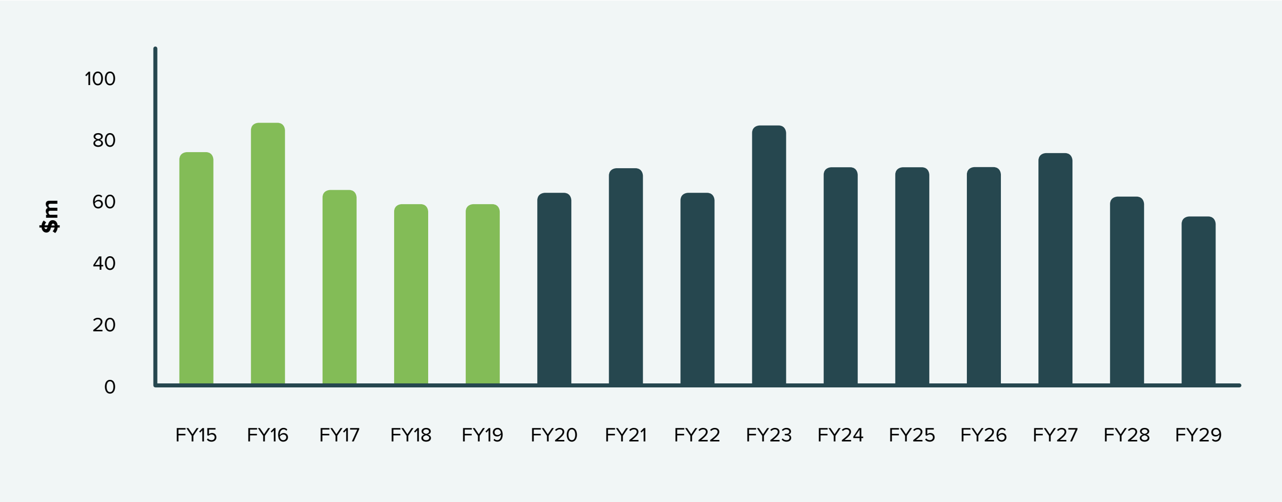
Capital expenditure

Our capital expenditure forecast shows a settling from the high level of FY16 when a number of post-earthquake major projects were completed. 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 the broad growth in residential connections over the post-earthquake years in certain locations. Our capex projections also support maintenance of safety levels and asset condition for asset fleets. The slight uplift in FY27 is due to work to replace a 66kV conductor link between Islington and Bromley GXPs.

Orion's top five capital projects and their drivers over this AMP period are listed in Table 1.1.

A list of our capital replacement projects and their drivers over the AMP period can be found in Table 1.2.

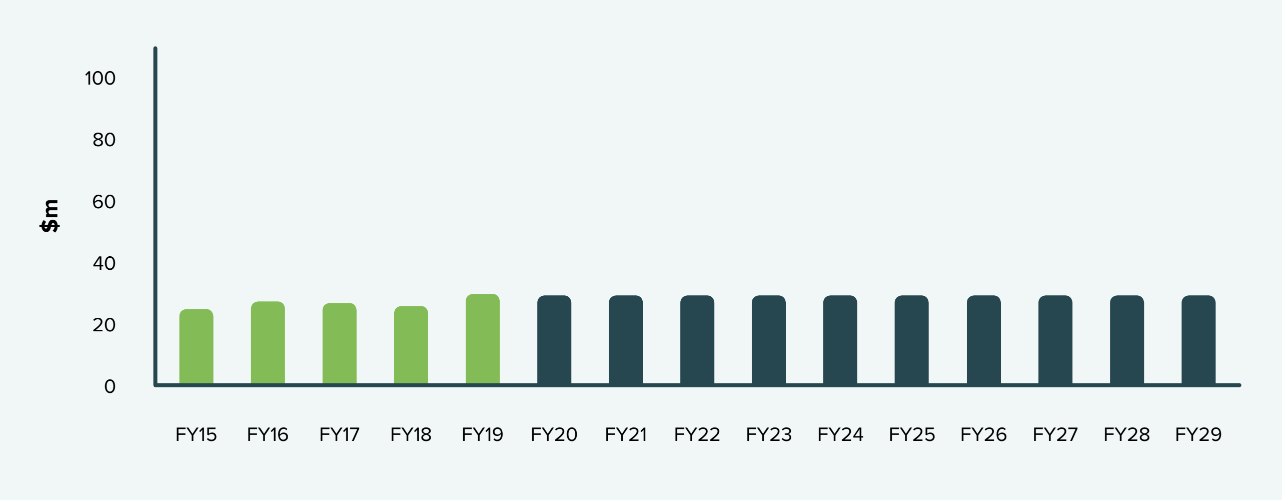
Figure 1.1 Total network capex (real) forecast ($000)



Operational expenditure

Our operating expenditure forecast shows an ongoing steady level of opex into the next 10 year period. We have taken into account 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.

Figure 1.2 Total network opex (real) forecast ($000)



A list of our maintenance projects and their drivers over the AMP period can be found in Table 1.3.

Strong asset management supported by people and systems

We are proud of how we performed as a business before and in the aftermath of the Canterbury earthquakes. We plan to continue to build on this performance legacy.

Our ability to deliver our AMP objectives relies on an appropriate level of capable, experienced and skilled resource – both within the Orion team, and via our service providers. We have spent 2018 repositioning our business through structure, roles and initiating cultural change to ensure we can both continue to keep delivering exceptional asset management and service while adapting and being more agile in our service delivery to meet our customers' needs for the future.

We are developing and maturing our systems and processes to ensure transparency, rich data for decision making, consistency and adaptability for the future. In particular we are extending our existing distribution management system to support further automation. Our asset management processes, standards, modelling, review and monitoring programmes are among the very best examples in New Zealand.

Our 2018 independent review of our asset management maturity supports these statements with our maturity across 19 aspects rated at Level 3, competent to excellent.

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

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.

AMP Section summary

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

Section 1: Executive summary

Our Introduction provides the context for this Asset Management Plan. Here we reflect on Orion's journey over the past eight years, the changing needs of our community, and the principles that guide our approach to managing our assets for the next 10 years.

Section 2: About our business

We deliver electricity to more than 202,000 homes and businesses in Christchurch and central Canterbury. In this section we explain how our asset management programme is driven by our Business Strategy, our Asset Management Policy and we set out the six areas of focus for our Asset Management Strategy.

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 FY18 and our targets for the planning period.

Section 5: About our network

This section details the configuration and history of our network, and our asset management process. Orion's network covers 8,000 square kilometres of diverse terrain, from Banks Peninsula and coastal Christchurch, to the remote high country in Arthur's Pass. By number of connections and energy delivered, Orion is the third largest electricity distribution network in New Zealand. 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.

A list of our capital replacement projects and our maintenance projects and their drivers over the AMP period can be found in Tables 1.2 and 1.3.

Section 7: Managing our assets

We take a whole of life approach to managing our assets. To drive that process, we develop maintenance plans and replacement plans for each asset class. 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 FY20 to FY29.

Section 10: Our ability to deliver

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

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

Table 1.1: Top five major capital projects and their drivers over the next ten years

Asset Management Focus Areas				Customer	Safe, reliable, resilient system				Environment	Future networks
Project	Project description	Capex forecast $000	Year	Load growth/ constraint	Safety	Asset health and criticality	Reliability	Resilience including Security of Supply	Environment	Future networks
New Belfast 66/11kV ZS and cables	A new substation and extension of the 66kV northern loop to supply load growth in northern Christchurch and address Region A security of supply gaps	**37,943**	FY20- FY24	✓				✓		
New Norwood Region B 220/66kV GXP and lines	New Region B GXP to increase resilience and support growth in Selwyn District and western Christchurch	**28,937**	FY22- FY23	✓				✓		
Lancaster ZS to Milton ZS 66kV link	A new circuit to increase security of supply for the CBD and reduce the consequence of a major outage at either Islington or Bromley GXP	**10,153**	FY27				✓	✓		
LV Monitoring	Installation of monitoring on our low voltage network	**9,931**	FY20- FY29	✓			✓			✓
New Burnham 66/11kV ZS	A new substation to supply load growth in Rolleston and shift load from Islington GXP to Norwood GXP	**7,994**	FY27	✓				✓		

Primary drivers   Secondary drivers

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

Asset Management Focus Areas			Customer	Safe, reliable, resilient system				Environment	Future networks
Network location	Project description	Capex forecast $000	Load growth/ constraint	Safety	Asset health and criticality	Reliability	Resilience including Security of Supply	Environment	Future networks
Overhead lines	Ongoing pole and conductor replacement, overhead to underground conversion and line switch replacement	**101,020**		✓	✓	✓			
Switches	This asset class replacement is driven by condition and risk. It also includes replacement of end of life LV panels	**90,068**		✓	✓	✓			
Underground	Replacement of cables and link boxes. It includes the supply fuse relocation programme which removes a legacy issue	**90,025**		✓			✓		
Protection	Work includes firmware upgrades, bus zone schemes, relay replacement/upgrades	**28,727**		✓	✓	✓			
Transformers	Replace end of life power transformers and faulty distribution transformers	**28,600**			✓	✓			
Management systems	System upgrade and enhancement. Purchase of spare parts for load control	**16,880**			✓	✓	✓		
Network property	This is for kiosk upgrade, convert pole structures with transformer to ground structure and battery	**10,500**				✓	✓		
Communications	Work includes radio/antenna/mast upgrade and fibre installation between zone substations	**5,475**			✓	✓			
Monitoring	Replace non-operational meters	**1,910**			✓	✓			

Primary drivers   Secondary drivers

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

Asset Management Focus Areas			Customer	Safe, reliable, resilient system				Environment	Future networks
Asset class	Work description	Opex forecast $000	Load growth/ constraint	Safety	Asset health and criticality	Reliability	Resilience including Security of Supply	Environment	Future networks
Overhead lines		**81,510**		✓ Primary	✓ Secondary	✓ Secondary			
Network property		**21,830**			✓ Primary				
Underground		**60,650**			✓ Primary	✓ Secondary		✓ Secondary	✓ Secondary
Management systems (MS)		**15,505**		✓ Primary		✓ Secondary			
Switches	Asset monitoring, inspections and maintenance	**12,600**			✓ Primary	✓ Secondary			
Transformers	Response to emergencies and supply interruptions	**8,450**			✓ Primary	✓ Secondary		✓ Secondary	✓ Secondary
Communications		**9,825**			✓ Primary	✓ Secondary			
Protection		**7,900**		✓ Primary	✓ Secondary	✓ Secondary			
Monitoring		**2,715**			✓ Primary	✓ Secondary			
Generators		**600**			✓ Primary	✓ Secondary			
Overhead lines	Vegetation management	**39,500**		✓ Secondary		✓ Primary			
Overhead lines	Improvements to maintain safety of poles and integrity of overhead components	**11,990**		✓ Primary		✓ Secondary			
Underground	Monitoring to maintain capacity and security of underground system	**4,870**	✓ Secondary			✓ Secondary	✓ Primary		
Power transformers	Refurbish, maintain key components of transformers to maintain or extend asset life	**2,000**			✓ Primary	✓ Secondary	✓ Secondary		
Network property	Improvements to maintain integrity of property protecting network assets	**1,850**			✓ Primary				

Primary drivers | Secondary drivers

2

About our business

Photo: Christchurch's revitalised Oxford Terrace where bars and restaurants along the banks of the Avon River are alive with people and electricity at night.

Contents

2.1 Purpose of our AMP

Our AMP sets out Orion's asset management practices for its electricity distribution business. We update and publish our 10 year AMP in March each year.

This AMP looks ahead for the 10 years from 1 April 2019. Our main focus is on the first 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 the changing needs 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. 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.

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.

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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 senior 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.

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 202,000 homes and businesses.

Under economic regulation we will transition from our current customised price-quality path (CPP), to a one-year default price-quality path (DPP) in FY20. We will then be subject to a five-year DPP reset for FY21 to FY25.

Rapidly changing technologies are providing opportunities for our customers to produce, store, and consume electrical energy rather than simply consuming energy provided to them. This change has the potential to alter the demands on our network assets and the services our customers require. Our assessment is that while requirements will change, our customers will continue to rely upon our network services for the foreseeable future.

Electricity distribution is an essential service that underpins regional, community and economic wellbeing. Orion takes pride in stewardship of our assets for the long term benefit of customers and the wider community.

2.3 Our local context

It is more than eight years since the 2010 and 2011 Canterbury earthquakes and our region is now a place of transformation, embracing change and innovation. We completed our earthquake recovery programme a year ahead of our 2019 target. Our work to restore and rebuild electricity services to earthquake damaged Christchurch has delivered a revitalised and more resilient network.

Our region is now looking to the future, and Christchurch is heralded as the "City of Opportunity".

Growth in the region, particularly new subdivisions, has seen Orion welcome more than 9,000 new customers to our network over the past three years. Building and maintaining our infrastructure to support that growth is a priority. So too is helping business and the wider community realise the benefits of New Zealand's sustainable energy resource.

2.4 Our business strategy

This AMP is underpinned by our Statement of Intent (SOI) and by our Business Plan, which sets out Orion's business strategy and the Vision and Values we work by. These are summarised in the following sections. Our AMP is consistent with and supports both our Statement of Intent and our Business Plan, although the scope of our business strategy is wider than our AMP.

2.4.1 Statement of Intent

Our SOI sets out our overall strategic/corporate objectives, 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.

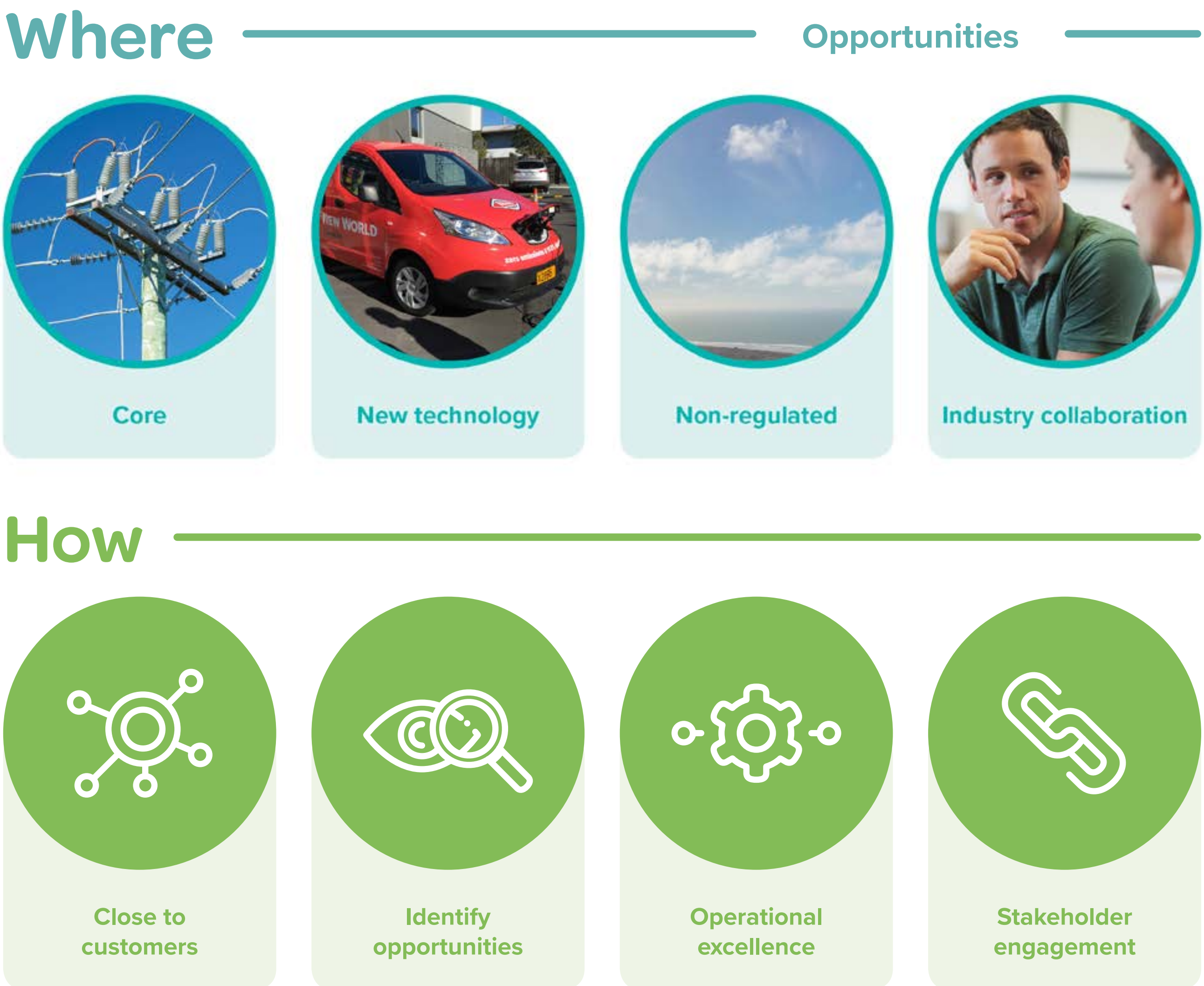
Our SOI notes that Section 36 of the Energy Companies Act stipulates that our principal objective shall be to operate as a successful business.

Our SOI has a number of performance targets each year related to:

- network development
- network reliability
- health and safety
- environment
- community and employment
- financial

Our AMP targets are consistent with and support our SOI targets, although the scope of our SOI targets is wider than in our AMP.

Figure 2.4.1 Business Strategy framework



2.4.2 Business strategy

Orion's business strategy is set out in our Business Plan. At a summary level, our strategy is to focus on:

- as our key priority, our core electricity distribution business
- the opportunities and challenges of new technologies and their integration into our core business
- profitable non-regulated activities – including through our subsidiary, Connetics
- opportunities for collaboration and efficiencies with other industry players

We'll continue to strive to be an industry leader with strong credibility.

Our business strategy creates value by maintaining the relevance and value of our core network investment through a deep understanding of customer technology trends and embedding emerging technology within our core business activity. This is complemented by opportunities in profitable non-regulated activity and industry collaboration. Various initiatives support these aims and are grouped under four objectives:

- close to customers
- identify opportunities
- operational excellence
- stakeholder engagement

The strategy framework, Figure 2.4.1, summarises this approach.

Context for this strategy includes:

- ongoing growth and regeneration in the region
- giving customers a voice in our asset management decision making
- we are in the midst of a global energy transformation
- significant new technologies are emerging, enabling households, businesses and the industry to rethink traditional notions of energy
- the opportunity for realising a more sustainable energy future for New Zealand
- the regulatory regime – principally the price-quality control regime
- increasing opportunities for collaboration, and creating opportunities with other electricity networks

2.4.3 Vision and Values

Orion's Vision and Values express how we conduct our business, and underpin all we do.

Vision

Connecting communities, igniting innovation

Our Values

Connect
We build real relationships with our customers and stakeholders so we can better power, energise and connect our communities.

Create
We are big picture thinkers and our innovation and agility enable us to identify opportunities, exercise sound judgment and learn continuously.

Collaborate
We work together, building on our strengths, our initiative and our commitment to ensure our communities trust us, our business is successful and our people and environment are valued.

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 Senior Leadership Team and Board.

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 2018 our board reviewed and approved, in principle, business cases for the first stages of these two projects:

- a **new substation at Belfast** and associated interconnection work across a number of stages proposed for the period FY20 to FY24. More detail on these projects can be found in Table 6.6.2 and Table 6.6.3. Project numbers 925, 929, 926, 924, 937, 491, 945, 942
- 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 6.6.4 and Table 6.6.3. Project numbers 940, 946, 931, 939, 941

2.5 Asset management plan development process continued

Also during 2018 our board reviewed three high value AMRs:

- 11kV overhead lines. See Section 7.5
- Protection. See Section 7.13
- Switchgear. See Section 7.10

As part of our internal audit programme, during 2019 we will commission Deloitte to undertake an audit focussed on the criteria we use for evaluating and prioritising projects.

This audit is expected to provide insights that will help us to further refine our internal processes around economic justification, work planning and prioritisation.

Based on our current approach we anticipate that during FY20 and FY21 the board will review and / or approve eight or more business cases and a minimum of four AMRs.

Figure 2.5.1 AMP development process

AMP development process

	Our board	Our management	Our customers
Strategy Ensure alignment of strategy between Stakeholders and customer expectations and across SOI, Business Plan, Asset Management Policy and Strategy	Board approves SOI, and business plan Reconfirm asset management focus areas with board (April)	Corporate strategy sessions (November) 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 service level assumptions (April) Progress update on AMP (June)	Review actual vs forecast expenditure, review asset failure modes & report on reliability performance, calibrate/update CBRM (June) Assess network and non-network alternatives. Assess load/growth	Stakeholder consultation Incorporate customer feedback in economic analysis (June)
AMR/Business cases Ensure data, systems, analysis tools, capability and engineering judgement result in appropriately documented efficient and prudent investment decisions	Key AMRs and business case as required (June and August) Ensure appropriate resource and capability	Create/update AMRs and business case (May and August) Network asset budget challenge (August)	Incorporate customer expectations
AMP Effectively communicate our expenditure plans, both short and long term, in away that demonstrates our best practice stewardship of the electricity distribution system	AMP review, challenge and sign off AMP/expenditure (November)	Signal key AMP improvements, and key expenditure step changes/ additions to board (November) Publish AMP. AMP presentation to staff (April)	Incorporate customer expectations

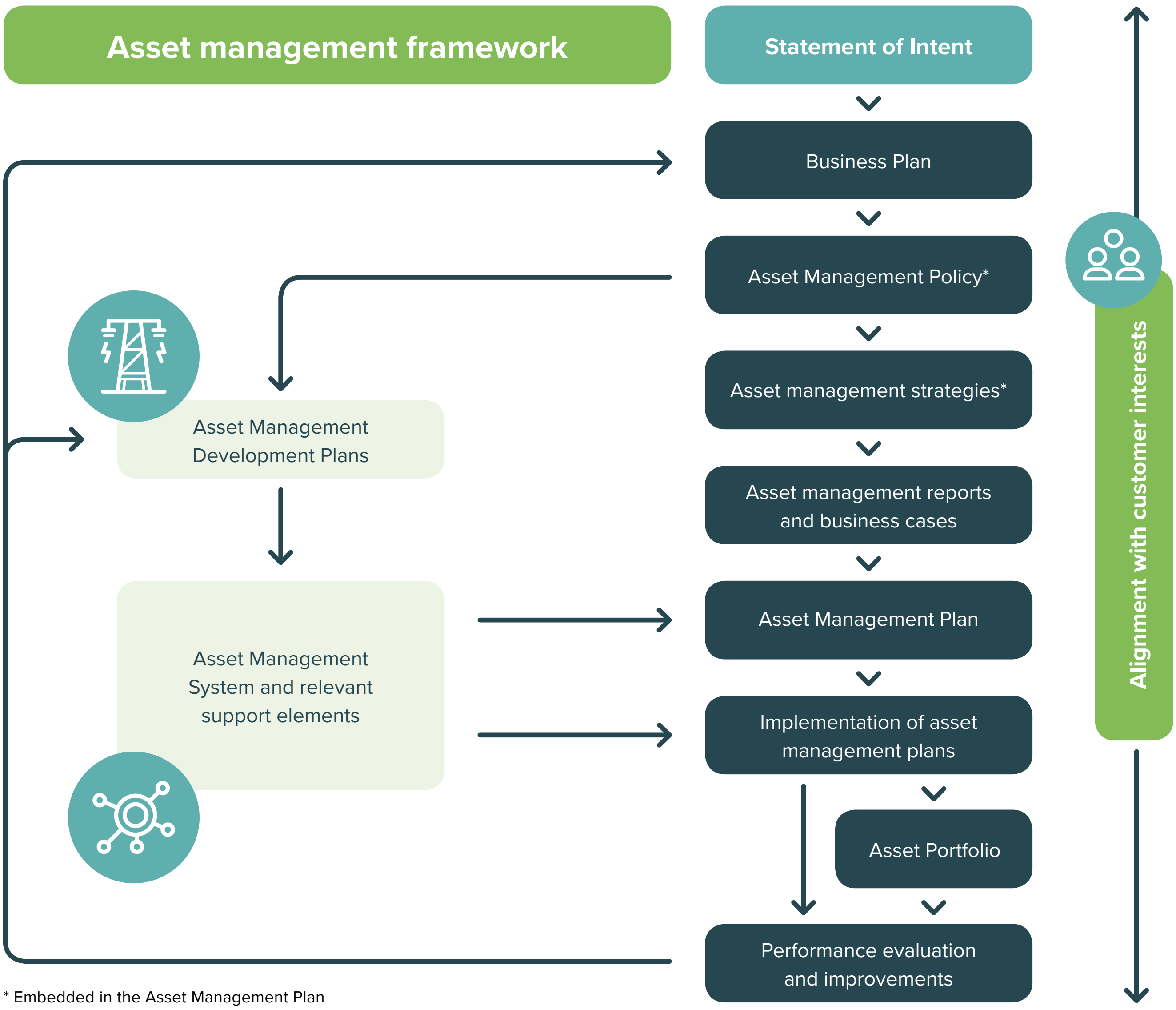
2.6 Asset management framework

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

- our decisions, plans, and actions are in alignment with our vision, values, and corporate goals
- 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 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

We use good asset management practices to consistently deliver a safe, reliable, resilient and sustainable electricity service that meets our customers' needs. We are committed to regular review of our processes and systems to ensure continual improvement.

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

- provide a safe, resilient, reliable and sustainable electricity service
- 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
- identify and manage risk in a cost-effective manner
- identify and evaluate relevant information in a cost-effective and timely manner
- recruit, develop and retain competent and motivated people
- build effective relationships with relevant stakeholders – including customers
- comply with relevant regulatory requirements
- be open to the benefits and opportunities that new technology can provide

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

- how our AMP fits with our wider governance 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

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

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

2.8 Asset management strategy

This section sets out our asset management strategy. The strategy describes the principles that guide us in making our day to day investment and operational decisions. It ensures our decisions, plans and actions are consistent with our Vision and Values, and our actions work efficiently and effectively towards achieving our Business Plan as well as our Asset Management Policy objectives. This is achieved through setting asset management focus areas and specific focus area objectives as described later in this section. We also set strategic initiatives, over and above our day to day activities to respond to change and continually improve our performance for the long-term benefit of our customers and stakeholders.

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 defines how we will continually improve and evolve our capability to meet the needs of our customers.

2.8 Asset management strategy continued

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 around six focus areas as shown and described in Figure 2.8.1.

Figure 2.8.1 Our areas of asset management focus

Close to customers & key stakeholders

Customers & key stakeholders
Being close to our customers by providing services they value and maintaining the trust necessary to retain our social license to deliver our services

Operational excellence

Safe, reliable, resilient system
Continually improving our activities associated with risk management planning, operating, maintaining and constructing the network

Health & safety
Keeping the public, our service providers and employees free from serious harm

Environment
Supporting sustainability by using resources wisely and actively seeking to reduce waste and the release of pollutants

Capability
Continually developing our capability as effective asset managers, skillful at utilising our assets to achieve our corporate vision and objectives and meet the expectations of stakeholders

Identify opportunities

Future networks
Being an enabler and embracing the significant technological change that is affecting the way that energy is being produced, stored and utilised

To deliver on our purpose, for each area of focus we have set objectives, principles and established initiatives that support achievement of our objectives.

2.8 Asset management strategy continued

2.8.1 Customers

Purpose: To ensure we deliver a service customers want and value, that meets their expectations. We will do this by:

- achieving our performance targets as set out in our Statement of Intent
- actively seeking to understand and meet our customers' needs now and in the future
- continually improving our customer engagement and our customer service
- being socially responsible in our actions

Focus area objectives: To achieve these goals, we have set focus area objectives, principles and supporting initiatives.

Focus area objective	Guiding principle
Work with our customers to obtain mutually beneficial outcomes in their long term interest.	We will identify and implement ways to improve our customers' experience, and stream-line the delivery of our services.
Provide services that our customers value.	We will regularly engage with our customers to understand how they value our services. We will tailor our price service level offering to meet our customers' expectations.
Meet customer expectations for levels of service.	We will manage our assets and operations to meet both regulatory requirements and customer expectations.
Seek to understand and predict future customer requirements and trends.	We are in a time of rapid technological change that is affecting how our customers produce, manage and consume energy. These changes and regional growth will alter the services our customers require and the assets we must provide to support this need. We will seek to understand and where possible, be ready to enable our customers to take advantage of new technologies, and customer trends.
Provide cost reflective and service based pricing for network access.	In the future, customers will interact with our distribution asset in new ways. Our pricing may need to evolve to reflect this while recovering prudent and efficient income sufficient to manage the asset sustainably.

Initiatives:

- complete a review of our customer facing business processes and implement improvements to enhance customer experience and operating efficiency
- develop and implement a formalised stakeholder and customer engagement plan
- undertake a programme of customer engagement to seek out our customers' views and give them a voice in our decision making
- complete our reliability management and forecasting strategy and implement actions
- monitor and regularly report on emerging customer energy production, storage, and consumption trends
- develop a network pricing roadmap and seek industry and customer engagement
- continue to engage regularly with our major customers to understand their business plans around decarbonisation and growth, and how these might impact our network planning

2.8.2 Safe, reliable, resilient system

Purpose: A safe, reliable and resilient system means delivering our services effectively and efficiently and making decisions that are in the long-term interests of our customers, while maintaining a financially sustainable business. We will do this by prudently and efficiently:

- innovating and continually improving the efficiency and effectiveness of our operations and service delivery
- investing in and setting target levels for the safety, reliability and resilience of our electricity distribution network through our network design and operation
- recovering our costs, including an appropriate return on investment
- identifying and managing our key risks including safety
- complying with relevant legislation, regulation, and planning requirements

Focus area objectives: To achieve these goals, we have set the following focus area objectives, principles and supporting initiatives.

Focus area objective	Guiding principle
Develop the network to provide capability, flexibility, and resilience at optimal lifecycle cost.	The future network must provide required capability while retaining flexibility to respond to changing customer requirements and resilience to cope with network events or natural disasters.
Apply a balanced risk vs cost approach to making asset maintenance and renewal decisions.	Maintenance and renewal activities manage risk arising from asset deterioration and ensure continuing fitness for purpose and legal compliance. We will treat asset maintenance and renewal activities as an investment that is justified through risk assessment and by benefits to customers and community as measured by risk.
Develop the network using a suite of standardised asset building blocks.	Standardisation of network equipment and designs provides lifecycle benefits arising from volume and consistency. Benefits include reduced procurement costs, minimisation of installation defects, reduced operation risk and the development of organisational experience to effectively manage the asset over its lifecycle.
Network innovation.	We apply 'best practice principles' in our network design and operation. This includes adopting and harnessing advances in technology where this can cost effectively improve our service performance in both our network and its supporting systems.

Initiatives:

- continue to restore resilience in the network and ensure that the network architecture provides sufficient resiliency and flexibility alongside other needs
- continue to improve use of condition and risk management tools for planning maintenance and renewal investments
- monitor technology developments in terms of capability and lifecycle costs. Where promising, conduct trials with a view to developing standardised solutions for implementation

2.8.3 Health, safety and wellbeing

Purpose: We aim to have safe work sites and a safe network for our employees, service providers, visitors, customers, and the public. We take a risk based approach to health and safety and balance the potential for harm with the value that our services provide to our customers and the community.

Focus area objectives: To achieve this goal we have set the following asset management objectives, principles and supporting initiatives.

Focus area objective	Guiding principle
Keep all our communities and people healthy and safe.	Providing electricity to the community by its nature presents hazards that could cause harm to the public, our service providers, and our people. This potential for harm is balanced by the benefits that electricity provides to our community both economic and in terms of people welfare. We will proactively identify and understand risk and optimise opportunities to reduce the potential for harm while retaining and enhancing the benefit of our service to society.

Initiatives:

- enhance our risk management framework to provide consistent management of risks and risk mitigation measures
- embed safety by design principles into our business as usual decision making including, network architecture, design, procurement, construction, maintenance and operation
- complete safe work practice reviews of construction and maintenance activities
- continue our active wellbeing programme

We will proactively identify and understand risk and optimise opportunities to reduce the potential for harm while retaining and enhancing the benefit of our service to society.

2.8.4 Environment

Purpose: We are committed to environmental sustainability, and supporting the New Zealand Government in achieving their commitment to reduce carbon emissions via the 2016 Paris Agreement. We strive to be sustainable by using our resources wisely and actively seeking to reduce waste and the release of pollutants. More than 90% of our carbon footprint comes from network losses and the carbon embedded in our network assets. By reducing system peaks through effective customer demand side management, we can reduce network losses and the need to acquire more assets. We will also adopt and enable use of electric vehicles to reduce the carbon emissions associated with transport.

Focus area objectives: To achieve these goals, we have set the following asset management objectives, principles and supporting initiatives.

Focus area objective	Guiding principle
Avoid unnecessary environmental harm due to our activities.	We will manage our activities, with the aim of causing no lasting harm to the environment. We will select assets, adopt work practices, and maintain the condition of our network to minimise waste, the release of pollutants and disruption to the natural environment.
Facilitate a low carbon future.	We will facilitate a low carbon future by being a facilitator of new energy technology. We will continue to reduce our carbon footprint by taking account of electrical losses when we design and operate our network. We will value the role that customer demand management plays in reducing the capacity needs of our network.
Manage risk of SF_6.	We recognise the environmental risks of SF_6 and will consider alternative equipment solutions wherever reasonably practicable.

Initiatives:

- maintain the viability of our customer demand management capability – see DSO initiative under the future network focus area
- continue to collaborate with partners to install public electric vehicle chargers around our region
- continue to seek opportunities to promote the adoption of electric vehicles, and ensure that our network is ready for charging loads
- develop distributed generation connection guidelines to facilitate the connection of embedded low carbon generation

We strive to be sustainable by using our resources wisely and actively seeking to reduce waste and the release of pollutants.

2.8.5 Capability

We will continually improve our capability to deliver our services effectively and efficiently, and with the required degree of dependability and resilience. We recognise the role that systems such as those defined by ISO 55000 can play in providing assurance and managing risk. While we do not seek formal accreditation to this standard now, we will adopt good practice principles and align our processes wherever this adds value for our customers.

Focus area objectives: We have set the following asset management objectives, principles and supporting initiatives to enhance our asset management capability.

Focus area objective	Guiding principle
Develop asset management system in alignment with ISO 55000.	An asset management system embodies the processes, IT systems and documentation to assure that asset management activities are aligned with objectives. Our asset management system has been developed in alignment with industry practices consistent with the scale and scope of our operations. We will continue to develop our asset management system and processes in alignment with the international standard for asset management ISO 55000 where this cost effectively provides operational benefits.
Accurate and timely asset information to support processes and decisions.	Accurate and timely asset information is a critical input to operational processes and longer term decision making. We will develop and maintain our asset information systems to balance the benefits of information against the cost to collect and maintain.
Identify and manage key risks.	The ability to transparently and consistently identify, rate and manage key risks is important for long term balanced decision making. We will implement a corporate wide risk management framework that ensures that key risks are visible to decision makers and acted upon proportionately.
Collaborate with industry peers for win/win outcomes.	New Zealand electricity distribution companies are small by international standards, with limited in house research and development potential. The projected rate of change is such that there will be benefits in collaborating with peers to develop solutions to optimise new opportunities.
Implement our asset management strategy objectives in a timely manner.	The asset management strategy captures the key areas of asset management focus, including business as usual, new, and enhanced asset management objectives. We will prioritise, resource and proactively manage the implementation of these objectives to ensure that we address our risks and opportunities in an appropriate timeframe.

Initiatives:

- produce an asset management system development roadmap for improving business processes, systems, and documentation to reach or exceed compliant levels in all areas of the Commerce Commission AMMAT framework
- formalise and embed a corporate risk management framework in alignment with ISO 31000: 2018
- identify mutually beneficial opportunities to collaborate with peer utilities for the benefit of customers and stakeholders

2.8.6 Future network

Purpose: Rapidly changing technologies are providing our customers with opportunities to produce, store and consume electrical energy in new ways. They provide opportunities for innovative network services. These new technologies may however create technical and business challenges, as they alter the required capabilities the network must deliver as well as the existing charging model for services.

We welcome these opportunities and will enable our customers to realise the economic and environmental benefits of adopting new technologies.

Focus area objectives: To facilitate the adoption of emerging energy technologies we have set the following asset management objectives, principles and supporting initiatives.

Focus area objective	Guiding principle
Facilitate customer adoption of new technologies.	We will facilitate the introduction of new energy technologies in a coordinated, efficient and cost reflective manner (via open access) that advances the wider interests of our customers and community.
Enhance understanding of low voltage network capability.	Customer adoption of new technology, such as photovoltaics and battery storage in their homes and businesses, will interact directly with our low voltage network, introducing technical requirements not anticipated when these networks were designed and built. We will improve our understanding of the technical capability of this asset and how it must evolve to meet future customer needs.
Implement no regrets actions that align with credible future scenarios.	Future customer requirements are uncertain and could evolve towards divergent scenarios. We will assess investment decisions against agreed scenarios, favouring options that provide flexibility and least regrets.
Release latent capacity of network assets.	Many network assets are thermally rated using conservative continuous ratings. Opportunities may exist to release latent asset capacity by using dynamic or cyclic ratings that take into consideration actual service conditions.

Initiatives:

- develop a roadmap to build our capability as a Distribution System Operator capability, providing a new platform for customer demand management
- undertake a LV system and communications architecture review to accommodate requirements for emerging technologies
- explore the application, benefits and risks of using dynamic and/or cyclic and seasonal ratings to determine asset capacity

We welcome these opportunities and will enable our customers to realise the economic and environmental benefits of adopting new technologies.

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).

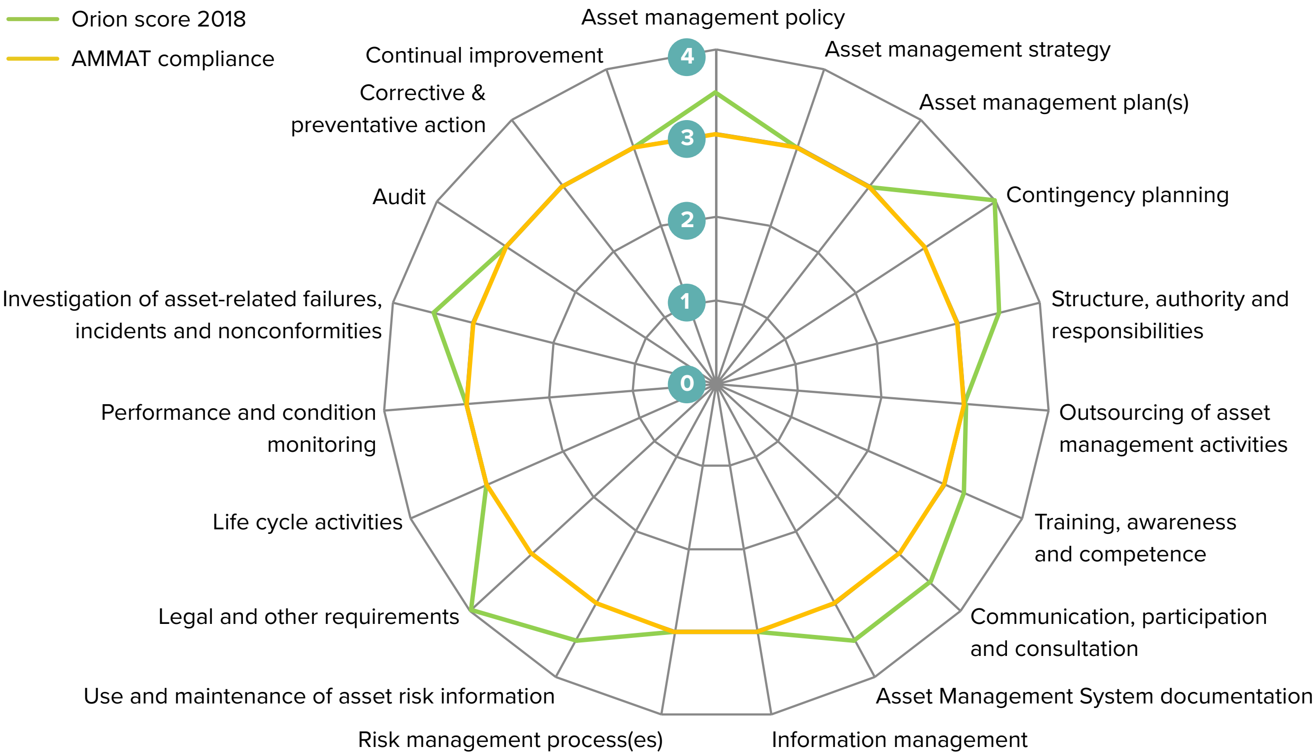
The tool provides a clear, detailed and consistent approach to assessing the maturity of an EDBs asset management. Assessment is undertaken based on the responses, both verbal and backed by evidence, to a set of 31 questions selected by the Commerce Commission from the internationally recognised PAS 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 2018 Orion engaged WSP Opus to undertake an independent assessment based on AMMAT and the EEA guidelines. We asked WSP Opus to:

- identify any blind-spots or gaps in our asset management processes and practices
- provide an unbiased indication of our asset management maturity and strategies.

The WSP Opus assessment determined that Orion achieved a maturity level of 3 or better across all elements – a good result. The review noted that our focus on improvement in asset management, recent substantial improvement in communication especially with our customers, in conjunction with recent reviews of documentation and process had continued our improvement programme. These and other improvements resulted in achieving credible gains in our score in this most recent AMMAT audit.

For full results see Appendix F.

2.10 Stakeholder interests

Our key stakeholders and their interests are summarised in Figure 2.10.1 and the process for identifying their interests is shown in Figure 2.10.2.

Figure 2.10.1 Stakeholders and their interests

Figure 2.10.2 Process for identifying stakeholder interests

Identify interest through forums

1. Customer surveys, 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. Contract performance reviews

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. Clear contracts with counter parties
6. Risk management

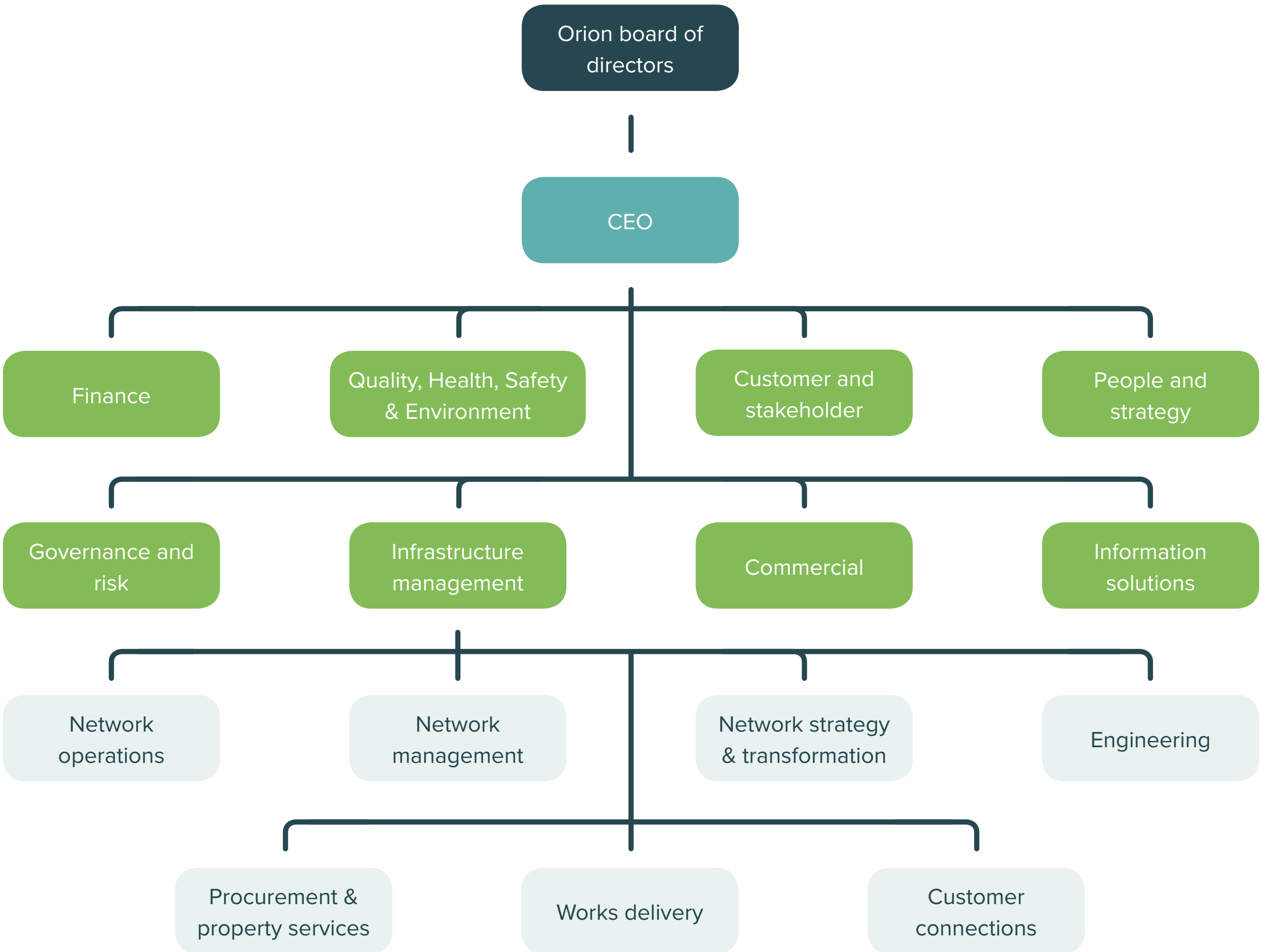
Manage conflicting interest

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



Board and executive governance

Our directors are appointed by its 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 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 senior leadership team is responsible for their budget and operating within their delegated authorities.

Infrastructure responsibilities

The asset management framework is governed by the board, senior 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 senior 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

Here we detail the current information systems we used to record, develop, maintain and operate our business. Systems and information flows are shown in Figure 2.12.1 on the following page. A description of the function of the main systems is detailed below:

1. Geographic asset information

Our Geospatial Information System (GIS) records the location of our network assets and their electrical connectivity. It is one of a number of integrated asset management systems.

Full access to the GIS is available to the Orion team at all times 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 GIS mapping team updates and maintains the GIS data. Data integrity checks between our asset database and the GIS are automatically run every week. Systems are in place to facilitate and manage GIS business development in-house.

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 held includes details of:

- 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.

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

4. Document management

For the last 3 years we have been migrating documents from an older style file system into new document libraries, based on Microsoft SharePoint framework. This process is now complete and the bulk of our corporate documents are created, stored and shared using SharePoint. Completing this migration is the first phase of a project that seeks to integrate and embed documents in key business processes, such as Works Management.

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.

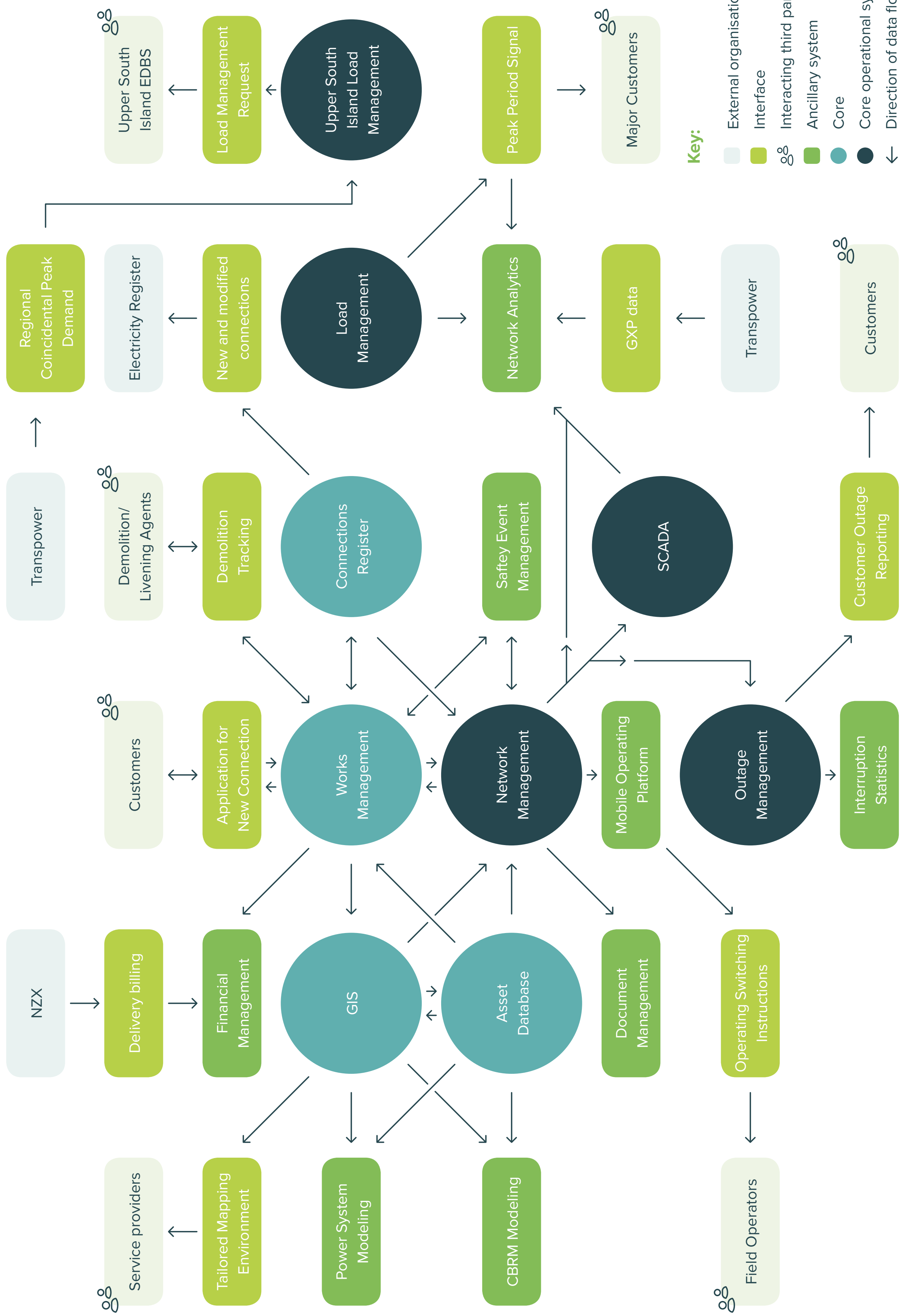
5. Connections-related service requests

A web portal allows service providers and the public to lodge requests for new and modified network connections. There is integration between the Connections and Works Management systems.

6. 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.

Figure 2.12.1 Core systems, information flows and key external entities



7. Financial management information system (FMIS)

Our FMIS (Microsoft NAV) delivers our core accounting functions. It includes the general ledger, debtors, creditors, job costing, fixed assets and tax registers. Detailed network asset information is not held in the FMIS.

There is an interface between the Works management system and the financial system to link project activities to jobs.

8. 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 line circuit breakers. We are also progressively installing SCADA at network substations throughout the urban area as old switchgear is replaced.

9. 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.

10. 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.

11. 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.

12. Customer outage reporting

A web-based application is used to display details of planned, current and past outages both internally and our web site. This is populated automatically by extracts from the PowerOn OMS and allows accurate real-time reporting of customer numbers affected by an outage. We also provide a real-time Outages map for the public.

13. Demolition tracking

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

14. 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 interruptions 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.

15. 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.

16. 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.

17. 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.

18. 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.

19. Power system modeling software

An integral part of planning for existing and future power-system alterations is the ability to analyse and simulate its' impact off- line using computer power-flow simulation.

Field Operators interact with our Control Systems in real time through a mobile application.

We use a power-flow simulation software package called PSS/Sincal, and have the ability to 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.

Because of harmonic problems encountered on the network supplied from Hororata GXP, we have also purchased the PSS/Sincal harmonics module to allow us to model the network harmonics. We are studying the feasibility of implementing the online power flow analysis package as part of our new network management system.

20. Mobile operating platform

Field Operators interact with our Control Systems in real time through a mobile application. 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.

21. 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:

- power outages, planned and unplanned, advised to street level
- load management, with near real-time network loadings, peak pricing periods and hot water control
- pricing
- publications, regulatory disclosures and media releases
- public safety and tree information

The interactive section of our website is a services portal that manages third party access to a range of services.

Services include:

- 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

The majority of our primary asset information is held in our asset database and GIS system. 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 have the ability to 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 the majority 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

Refinement of data is an ongoing process. Compliance inspections and maintenance regimes are the main source from which to confirm or update data. As we replace aging assets with new assets over time all estimated data will be superseded.

Although there will inevitably be some minor errors and improved information will always be required, we believe our information for the majority of the network is accurate.

2.12.3 Short term developments

We have innovated by developing a new app that means our service providers can record the results of their maintenance inspections of equipment directly into the system as they go, making the process faster and more efficient. This innovation delivers on our asset management strategy focus areas to enhance health and safety, and continually develop our capability.

Customers benefit as a result of this more cost effective and efficient maintenance programme that uses electronic data collection to provide timely access to data when making our asset management decisions.

Other short term developments we are planning are:

- **Upgrade of network management mobile module –** We expect to complete the introduction of new mobile application to support our Operators in the field. This application links the field to PowerOn in real time and replaces the native GE mobile module. This project will introduce new handsets and include data collection facilities that are not available in the current software
- **Service provider online switching release request system –** The online release request system will manage requests from multiple service providers who wish to undertake planned work on network equipment. While our management of unplanned events has improved dramatically, planned work management has remained largely a manual, paper-based system which does not take advantage of the safeguards and efficiencies inherent with this technology.

2.13 Assumptions

2.13.1 Significant assumptions

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. 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.

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 resilience and reliability 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.

Any spur assets purchased or newly developed distribution assets are expected to perform within their parameters.

We are currently reviewing our reliability targets to test their appropriateness in a changing technical and operational environment that includes asset technology enhancements and increased safety requirements.

4. Network development

Section 6 of this AMP outlines projects that will ensure that our network will continue to meet our customers' expectations of supply. Our plans acknowledge the reduced demand associated with the development of the Central Plains Water scheme and also the increased energy efficiency of businesses and households.

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 have assumed this participation will continue. 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 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.

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 (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

No changes are proposed to the existing business of Orion. All forecasts in this AMP have been prepared consistent with the existing Orion business ownership and structure.

2.13.3 Sources of uncertainty

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
- **The regeneration of Christchurch –** The pace of regeneration of Christchurch's Central Business District and the future of 'red zone' are influenced by The Crown, Christchurch City Council, Ōtākaro Ltd and Regenerate Christchurch. It's also influenced by private developers. There is uncertainty regarding the timing and extent of some key recovery projects as the cost of the rebuild escalates
- **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 are researching the impact of these technologies for different uptake scenarios
- **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 customer requests such as Fonterra and Synlait 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 might follow. This will put further upward pressure on labour rates and availability in the next period.

National policy, economic or technology changes could lead to different levels of network investment.

2.13.4 Price inflation

In this AMP our cost forecasts are stated in real dollars in FY20 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
- major equipment failure and/or a major natural disaster 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

3

Managing risk

Photo: Our Control Centre is at the heart of operations for our network. Here Orion Network Controller, Jeremiah Torres, radios our Network Operators in the field for on-site information.

Contents

3.1 Introduction

Diligent risk management strengthens our ability to provide a network that is reliable, safe and resilient. Our risk management aims are to:

- support our purpose and objectives
- 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
- we can always improve
- risk management is all about creating and protecting value for our customers, our community, our people and our key stakeholders

3.2 Our risk management context

Our customers and our community depend on our service, so it's essential we identify and manage our key risks. As we emphasise in our SOI, we have an important role in meeting our community's aspirations for:

- a 'liveable' city and region – with strong, connected communities
- a healthy environment – with a prosperous economy.

Electricity is a fundamental necessity in the modern world and this will continue for the long-term. Our customers and community depend on our electricity delivery service, all day, every day. Our community especially depends on electricity following high impact low probability (HILP) events, especially following natural disasters 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 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. GNS Science estimates that there is a 30% chance of a major Alpine Fault earthquake in the next 50 years
- is subject to weather extremes – including snow and/or wind storms
- has cold winters
- has no reticulated natural gas
- has urban 'clean air' restrictions on the use of solid fuel heating

As a 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.

We also know that:

- our customers will increasingly convert to electric vehicles (EVs)
- our major business customers will increasingly convert to electricity for large heating
- other local lifelines utilities depend on electricity
- electricity distribution networks have inherent hazards and risks by their very nature
- we must comply with relevant legislation – including the Health and Safety at Work Act and the Electricity Act
- our industry is otherwise highly regulated – including via price-quality regulation pursuant to the Commerce Act
- 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

3.3 Our purpose and risk appetite

In light of the context in which we operate, and through our ongoing customer engagement, we know our customers want us to provide a safe, reliable, resilient and sustainable electricity delivery service – and this effectively defines our purpose.

Given our context and purpose, we have a cautious risk appetite for our network management. Our cautious risk appetite is also consistent with our SOI objectives to:

- act in the long-term interests of our customers, our community and our shareholders
- operate as a successful and sustainable business
- comply with relevant legislation.

We believe that our cautious risk approach to our network management is in long-term interests of our customers and community because:

- of our region's unique context
- our customers tell us network reliability, resilience, safety, a focus on the future, and customer service and responsible environmental management are important to them – See Sections 4.2 and 4.3
- our earthquake experience tells us HILP events can cause prolonged periods without power supply, and our customers have a low tolerance for prolonged outages
- our customers, the community and other lifelines utilities depend on electricity all day every day – and after HILP events
- our customers and the community may suffer extreme adverse consequences, financial and non-financial, from prolonged or frequent interruption to their power supply, especially if they happen in winter
- in a 2017 survey, our customers told us that investment in resilience represents good value for them, and almost 70% of our residential customers stated that fast restoration of power following severe weather events and natural disasters is very important to them, see Section 4.3.3
- the CDEM Act requires us to be able to function to the fullest possible extent during and after HILP events

For our critical network assets and systems, we aim to continuously:

- use the most reliable and comprehensive information to identify and assess the potential consequences and the likelihood of failure
- apply our experience, knowledge and sound judgment when considering how to address any key risks
- take reasonably practicable and timely steps to treat those risks

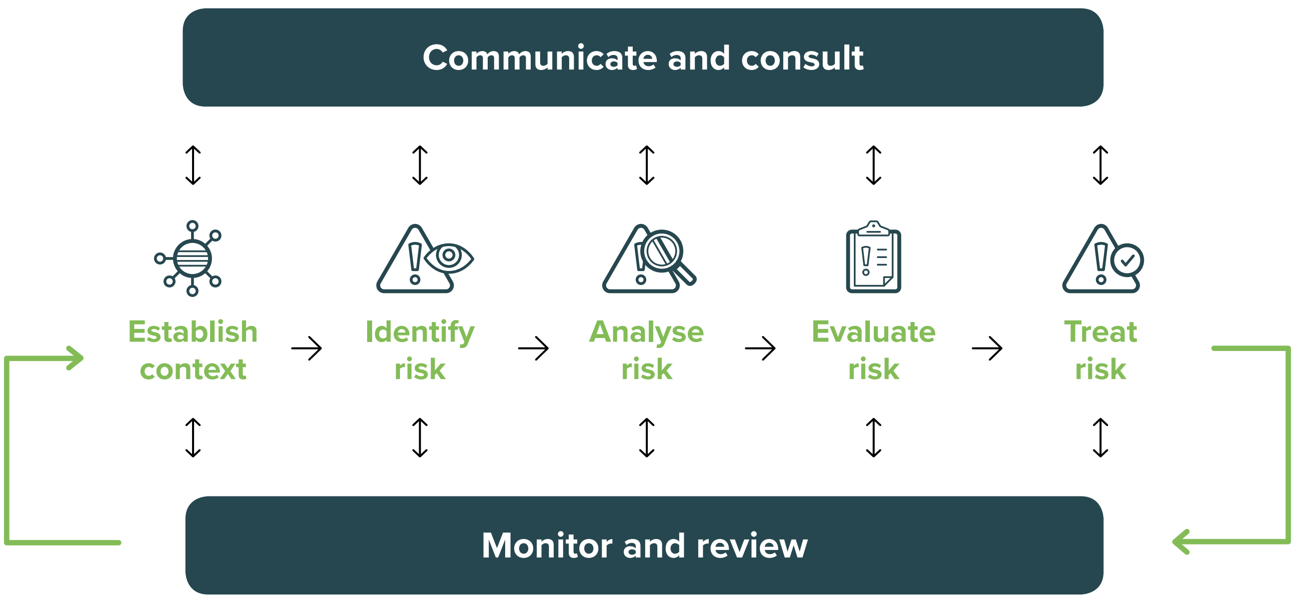
We especially focus on our critical network assets and systems, for example our network control systems and our sub-transmission, 33kV and 66kV assets, as these supply the greatest numbers of our customers and they can be the most complex to repair or replace if they are damaged.

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



In summary:

- we first establish the appropriate context that's relevant to our objectives and our significant risks
- we then identify those significant risks – especially those with significant potential consequences
- we then analyse those significant risks – we rate their potential consequences and their likelihood
- we then evaluate those risks – we decide whether/how to treat those significant risks to eliminate, reduce, transfer or accept them
- we then act – in a timely and effective way, in accordance with our risk evaluation

We aim to:

- understand our risks – including the risk that our risk treatments may not work
- consider good evidence, experience and history to inform, but not cloud, our judgments
- collaborate internally and externally as appropriate. A collaborative approach helps to bring different experience, knowledge and perspectives and helps to reduce bias and blind spots
- acknowledge that we can't prescribe procedures for all risks, in all contexts, at all times
- be proportionate and treat our significant risks as reasonably practicable [1]
- continually improve

Consistent with the international risk management standard (ISO 31000:2018), we represent our overall risk management culture as depicted in Figure 3.4.2.

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.

[1] Consistent with the definition in the Health and Safety at Work Act, reasonably practicable is what can reasonably be done, weighing up all relevant matters, including:

- the potential harm and the likelihood of that harm
- what is known, or ought to be known, about a risk and ways to treat it
- the costs to treat the risk, including whether the costs to do so are grossly disproportionate

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 emerging technologies
- plan and build for network capacity, resilience and reliability
- monitor, maintain and enhance the condition of our key assets and systems via our ongoing lifecycle management
- operate our network
- 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 healthy and collaborative culture – with effective engagement and communication
- 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 Ara Trades Innovation Centre, which has an electricity distribution trades training centre
- the University of Canterbury's Power Engineering Excellence Trust

There is increasing competition from other infrastructure providers in New Zealand for competent team members. Our strategy 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.

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

3.4.4 Our regulatory risk management

The electricity industry is highly regulated, via multiple regulatory agencies. Our key regulatory risks include:

- health and safety compliance – for example, the electricity industry has multiple regulatory safety requirements
- electrical quality compliance – for example, regulations set electrical voltage standards we must achieve
- network reliability compliance – for example, the Commerce Commission sets annual network reliability limits we must achieve
- network pricing – for example, the Commerce Commission sets the maximum delivery price we may charge each year
- regulatory information disclosure requirements compliance
- environmental compliance
- vegetation management compliance

We aim to comply with our regulatory obligations and to constructively engage with regulatory agencies on key regulatory developments.

3.4.5 Our commercial 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 revenue risks through:

- appropriate delivery service agreements with electricity retailers and major customers – this includes: payment terms and credit requirements, although our credit requirements are limited by the Electricity Industry Participation Code. Our delivery services agreements also include caps that limit our potential liabilities, although the Consumer Guarantees Act reduces our ability to cap our liability in certain circumstances
- good service and constructive engagement with electricity retailers
- active engagement with regulatory agencies

3.4.6 Our insurance

Insurance is the transfer of specified financial risks to other parties, in particular, 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 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) in Australasia, are:

- lost revenues – for example, due to depopulation following a catastrophic event
- 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

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 those key 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 two teams that support line management to undertake risk management:

- Governance and Risk – two FTEs help to coordinate our management and governance processes, our risk management framework and our insurance programme
- Quality, Health, Safety and Environment – six FTEs help our line management to continuously improve our processes in these areas

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 will be different, so we expect to plan-to-plan following such events.

The CDEM Act requires us to:

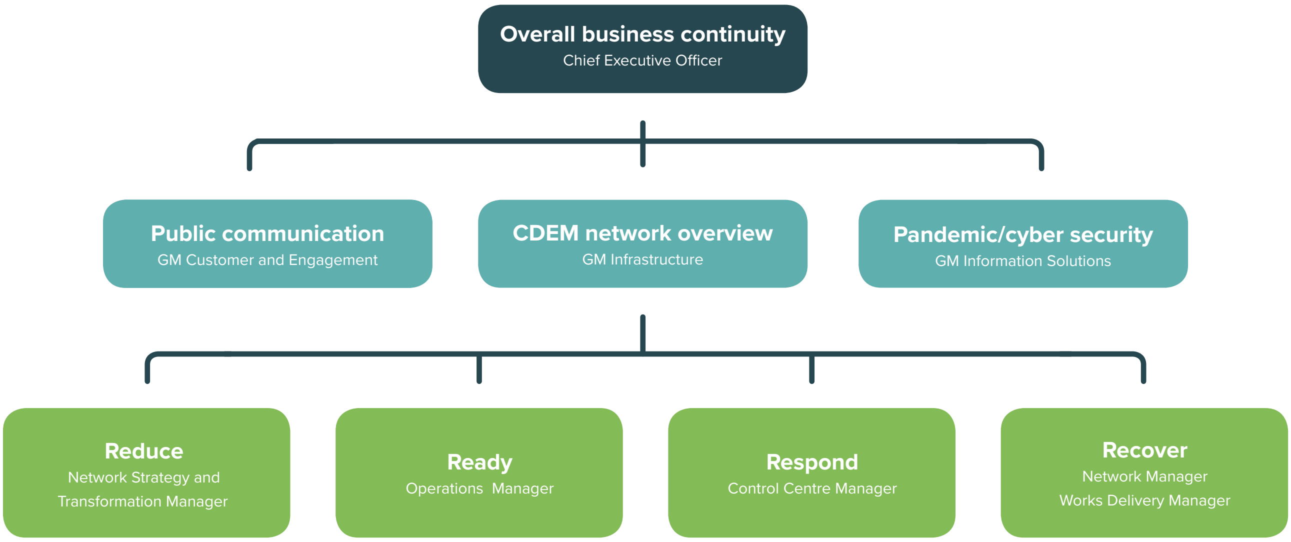
- function during and after an emergency, and have plans to support this
- participate in CDEM planning at national and regional level if requested
- provide technical advice on CDEM issues where required

We align our business continuity responsibilities using Civil Defence's 4Rs approach to resilience planning – reduce, ready, respond and recover.

Our 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 Canterbury earthquakes and this significantly reduced the impacts on our network, our customers and our community. We have also invested to increase our IT defences 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.

  To enhance our preparedness to respond to major events, we reviewed our crisis management plan in 2018 and created crisis information packs for our key response staff.

  This efficiency improvement delivers on our asset management strategy focus on improving our network 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 their 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 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.

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 the different types of risk we face, such as:

- natural disasters
- health and safety
- people and competence
- environmental
- financial – including revenue shortfalls, cost overruns and fraud
- project management and procurement
- customer service – including network capacity constraints or network outages
- IT systems – including cyber security
- legislative and regulatory risks
- legislative compliance risks
- 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 how we should judge how significant or important particular consequences might be in any situation. Our risk rating guidelines also aim to 'score' our key risk assessments as a product of consequence and likelihood. This includes a numbering system from 1 to 25 to calculate ranking as shown in Table 3.6.1.

Table 3.6.1 Our risk assessment guidelines

Likelihood		Consequence				
		Minor	Moderate	Serious	Major	Severe
Almost certain	80% to 100%	11	16	20	23	25
Likely	50% to 79%	7	12	17	21	24
Possible	15% to 49%	4	8	13	18	22
Unlikely	5% to 14%	2	5	9	14	19
Most unlikely	0% to 4%	1	3	6	10	15

Our **consequence rating** guidelines aim to inform our judgments. We recognise that there could be several different potential consequences that need to be considered – 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. For example, the relevant time periods could be:

- a task – for example, today's traffic management for a new substation build
- a job – for example, the whole time period a new substation build
- a period – for example, the subsequent warranty period for the service provider who built the substation for us
- a long period – for example, the long-term resilience/reliability/safety standards for the new substation

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
- how often the consequence has occurred in the past and/or elsewhere
- new factors that make past experience less relevant

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

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.

Figure 3.6.1 Our five main risk evaluation options

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

Given our wider context and our 'cautious', relatively risk averse, risk appetite, 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?

3.6 Our risk assessments and risk evaluations continued

As a general principle, the higher the risk the more decisively we act. Our overall risk treatment 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	Quarterly, immediate if new	Board of directors
Very high	Take timely action to treat risk	Quarterly, and as appropriate	CEO/SLT
High	Accept, but treat risk if cost is proportionate to risk	Quarterly, and as appropriate	SLT
Medium	Accept, but treat risk if benefits outweigh cost	Annual, and as appropriate	Relevant manager
Low	Accept, manage as per normal procedures	As appropriate	Relevant manager

3.7 Our key 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 or severe storm
Fatality or serious injury	Fatality or permanent disability to a worker, service provider or member of the public
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

Our overall assessments for these key risk categories (six specific risks, with 1 being the highest risk and 6 the lowest) are shown in Table 3.7.2.

Table 3.7.2 Our overall key risk assessments

Likelihood		Consequence				
		Minor	Moderate	Serious	Major	Severe
Almost certain	80% to 100%					
Likely	50% to 79%			3		
Possible	15% to 49%		6			1
Unlikely	5% to 14%			5	2 4	2
Most unlikely	0% to 4%					

1. Earthquake risk – next 50 years
2. Fatality – next 5 years – severe consequence
   Serious injury – next 5 years – major
3. Severe storms – next 5 years
4. Serious cyber security breach – next 5 years
5. Tsunami risk – next 50 years
6. Major network asset failure – next 5 years

3.7.1 Major earthquakes

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% probability of a major Alpine Fault earthquake in the next 50 years – and the risk of other local fault lines only increases that 30% probability 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 centred further away from our urban network and would not be as sharp as the 22 February 2011 earthquake, but it would have a far longer duration – perhaps some minutes. This would test the resilience of our network in different ways to 2011. 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 certainly be even more severe if it occurs in winter.

Assuming a 30% to 40% chance of a major earthquake in the next 50 years and the 'severe' consequences of such an event, we assess this risk as 'very high' (orange) over an appropriate planning period for this risk of up to 50 years.

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 our recovery initiatives we have further enhanced our earthquake resilience. For example, we have:

- rebuilt our existing 66kV network in the eastern suburbs – using better and diverse routes, improved modern cables, and improved trench design
- invested to create a new 66kV cable 'northern loop' – creating a more interconnected 66kV urban sub-transmission system
- improved the resilience of key network assets – including local spur assets we have purchased from Transpower since 2012 – and we will continue to improve these assets over the next few years
- moved to a resilient (IL4) and fit-for-purpose main office, which includes our 24-hour network control centre
- built a standby hot site, that can be used if our administration office and control room become unusable after a major event
- moved our key network service provider, Connetics, into a new, resilient and fit-for-purpose base
- moved our key network component spares to diverse sites that are less susceptible to natural disaster risks
- improved the capability and resilience of our operational systems
- improved our supply to key lifelines entities – such as the port and the airport

Our earthquake recovery work since 2011 has built on our substantial pre-earthquake resilience work and our already interconnected urban high voltage network. This facilitates our ability to switch load around our network when necessary.

Our earthquake recovery work since 2011 has built on our substantial pre-earthquake resilience work and our already interconnected urban high voltage network.

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 are old technology and the skills to maintain and replace them are increasingly disappearing internationally and locally. These were the type of subtransmission cables that failed in the eastern suburbs in the 2011 earthquake and we had to abandon them and replace them completely – first by way of an emergency temporary overhead line, and subsequently over the next three years, by way of replacement underground cables.

Although our remaining 40km of oil-filled 66kV cables are not in the eastern suburbs and so are less susceptible to poor ground conditions near the Avon River and estuary, they may be more 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.

As in February 2011, a major future earthquake will have significant impacts on the ability of some our team members to contribute to our respond and recover 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 periods
- 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 quake 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 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 between one and three days areas of our network near the east coast. We rate this event as a medium risk (light green). Since 2011, we have significantly reduced the potential impacts of a major tsunami as our key service providers have moved significantly further inland. Our network assets near the east coast will inevitably be exposed to tsunami.

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

3.7.3 Significant storms

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 affect fewer 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 'nor wester' wind storm in 1975, snow storm in 1992 and severe 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 cross arm types – as appropriate for credible wind and/or snow loadings. An important point here is that that 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 inherent 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 inherently more susceptible to outages caused by trees, but they are inherently faster 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.

Overall, we rate severe storm risks as medium for urban areas, around 80% of our customer connections – and high for rural areas, around 20% of our customer connections.

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.

3.7.4 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.

Our approach to actively identifying and mitigating the risks typically associated with operating an electricity network includes:

- ensuring a collaborative, learnings based focus into our safety incident investigations both internally and with our service providers
- improving our risk management by being more rigorous in our risk assessment and mitigation processes
- incorporating environment and quality assurance oversight into our health and safety team to provide a better overview of these interrelated factors
- undertaking a formal quality, health, safety and environment audit programme
- continuously improving our reporting process which results in better visibility of the number and nature of actual and potential incidents reported in our real time online incident reporting system
- we investigate and follow-up all reported incidents and implement any learnings as part of our continuous improvement philosophy
- working with our service providers to encourage safer practices when working around Orion infrastructure
- having trained and competent field workers who are skilled in working in a dynamic and complex environment
- increasingly using 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 assist us with understanding 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 'safety in design' process. We carefully document and regularly review our work policies, processes and procedures to ensure they provide accurate guidance for those working on our infrastructure.

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

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.

Much of the 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 EDBs, the Electricity (Safety) Regulations requires 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 the 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 inherently 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 a 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.

3.7.5 Cyber security

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 safe, reliable and resilient service. We have two key categories of information systems risk:

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

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

- robust systems procurement and maintenance – hardware and software
- rigorous change management
- good practice for regular and ongoing data and system back-ups and archiving
- highly resilient facilities
- robust security – computer network and physical
- mirroring of key hardware and systems between physically separate sites
- undertaking 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.

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 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 Other risks

In Section 6 we identify where the load at risk exceeds our security standard and the proposed mitigation. In this section, we discuss two risks that are often raised. We rate these as relatively lower risks for our network.

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 and we have an SOI target to reduce this further to below 0.8%. Our environmental management procedure for SF_6 gas aims to ensure we achieve those targets commitment.

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

- asbestos
- hazardous substances
- items of archaeological significance

New technologies

New technologies will continue to create issues and opportunities for our electricity distribution network. Examples include:

- the growth in electric vehicles – this will cause greater demand for our network
- the conversion of industrial heat processes from (mostly) coal to electricity – this will cause greater demand for our network
- the impact of battery technology and energy management systems – these will have demand impacts for our network
- the impact of more distributed generation, such as solar PV – this will potentially create more complex two-way flows between our network and end-use customers

Our risk management approach is to:

- keep up do date with technologies as they emerge
- assess the potential impacts 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 assess these risks as low to medium in the long-term – there is still a compelling customer need for our delivery service and our network should be capable of accommodating changing customer needs as they arise.

New technologies will continue to create issues and opportunities for our electricity distribution network.

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 30, electricity has the fourth highest overall score.

Table 3.7.3 NZ Lifelines Council interdependency ratings during/after HILP events – Sep 2017

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	1	2	3	3	3	3	2		2	2	3	3	3	**30**
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	1	1	1	1	1	1	**12**
Gas	1	1	1	1	1	1	1	1		1	1	1	1	**12**

The New Zealand Lifelines Council also ascribes the same individual ratings and total dependency score of 30 to electricity for ‘business-as-usual’ – the highest total dependency for any lifelines utility.

Over the last few years, we have improved the resilience and reliability of our service to other key lifelines utilities, including:

- **Lyttelton Port** – in FY18, we significantly improved the resilience and reliability of our 11kV overhead feed into the Lyttelton area. We also transferred two of our back-up emergency generators to the port as further back-up. In FY19, we installed a new 11kV cable through the road tunnel to provide a further alternative supply to Lyttelton. These projects have significantly increased the resilience of our supply to the port and the wider Lyttelton region
- **Christchurch International Airport** – in FY16, we installed a new 11kV cable feed so that the airport can now be supplied from our Waimakariri and Hawthornden zone substations. This project has significantly improved the resilience of our supply to the 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.

Grid exit points (GXPs)

Asset failure at either our two key GXPs, or our network equipment at those sites, at Bromley or Islington is 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 there and we will continue to implement improvements over the next few years. Transpower has also implemented improvements at our grid exit points, 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 switchroom.

Our 66kV sub-transmission 'Northern Loop', commissioned in June 2016, has created a more interconnected sub-transmission system which significantly reduces our risks to single grid exit points.

Zone substations

Zone substation failures across our network could be caused by liquefaction or asset failure. This could result in an outage of up to one day to our network. For most of our 51 zone substations, we rate this event as a low to medium risk, with a moderate consequence and unlikely likelihood.

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

We also have:

- targeted interconnectivity and diversity of supply
- 'n minus 2' contingency switching plans
- oil containment bunds at key sites
- simple and low-cost hold-down ties for transformers

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.

Orion's overhead lines in rural areas are most 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. This may result in an outage of up to three days to some areas of our network. We rate this event as low to medium risk, with a serious consequence and rare likelihood.

We have rigorous engineering standards and systematic inspection processes in place for our overhead lines and towers. Also, we have in place a vegetation management programme which minimises the impact of trees on overhead lines particularly during storm events.

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. As we note in Section 7.7, 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, refer to Section 5.6.2.

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:

- 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 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 EDBs 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 have done and are doing 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
Overarching asset management policy (Section 2.8)	Our asset management 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	Our asset risk plan for major incidents or emergencies. Topics include: • our key natural disaster risks • our rating system for our key network components most at risk • our main risk treatments, 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, our participant rolling outage plan outlines how we respond to grid emergencies that have been 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	Our security of supply 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	Our security policies and procedures that aim to restrict physical access to our electrical network and associated infrastructure. Underpins our commitment to provide a secure and reliable network for our customers and community, and safety for the public, employees and service providers. Our main focus is to restrict access by unauthorised personnel. Some aspects also affect authorised personnel. Our general aims are to prevent unauthorised entry by the public and opportunist intruders who don't have specialised tools, and to slow/inhibit determined intruders. 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 corporate manager is responsible for their respective plans.
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 have identified 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 major outage communication plans. In emergencies, we aim to keep our customers and the community informed, and work closely with our key stakeholders in emergency management.

4

Customer experience

Photo: Orion General Manager Infrastructure, Steve Macdonald, participating in one of our "Powerful Conversations" with customers.

Contents

4.1 Introduction

Orion works hard to better 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 six areas of focus in our asset management 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 a diversity of 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 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.

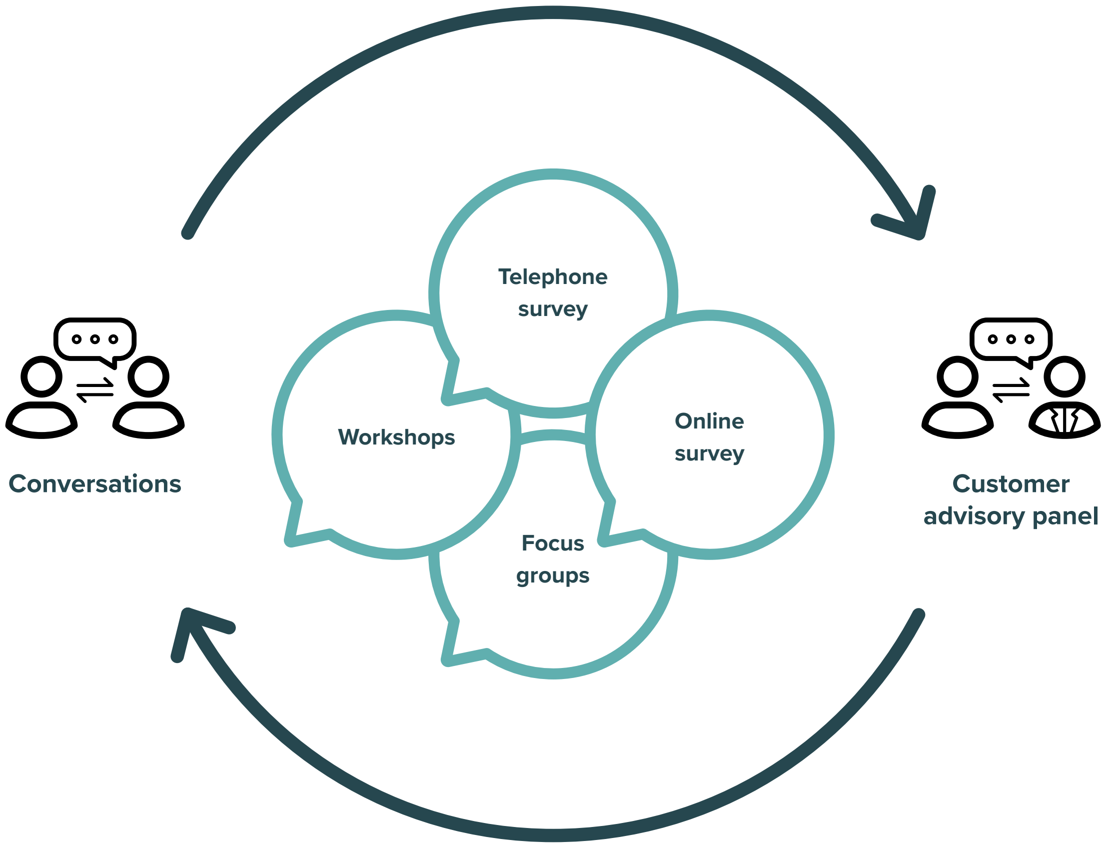
Orion works hard to better understand the needs of our customers, and give them a voice in our decision making.

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 customer's 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 are changing and they 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.

4.2.1 Customer Advisory Panel

Established in 2018, Orion's Customer Advisory Panel is a forum for us to engage with leaders of community groups 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.

Panel members represent a cross section of the community and reflect the diverse perspectives of our customers.

The first of its kind in New Zealand, Orion's Customer Advisory Panel is an innovation in customer engagement that provides valuable insights that inform all areas of focus in our asset management strategy. Customers benefit from having their perspective represented in decisions about future investment and service enhancements.

Figure 4.2.1 Our customer engagement helps Orion to:

4.2.2 "Powerful Conversations" workshops

We commenced a series of "Powerful Conversations" workshops with groups of around 15 customers, exploring their views on the price/quality trade-off inherent in network investment decisions that affect reliability, resilience and safety, and sought their opinions on future technology options.

4.2.3 Customer insights programme

Orion commissions a robust programme of surveys carried out by professional independent researchers to validate our interpretation of our customers' feedback.

Each year we commission a telephone survey of 800 urban and rural residential customers. This gives us valuable insights into their expectations and levels of satisfaction with our service, views on network reliability and the effectiveness of our communications.

In December 2017, we also commissioned an online survey of more than 800 residential and business customers to verify and quantify our "Powerful Conversations" workshop conclusions about customer's attitudes to the price and quality balance involved in network investment decisions that affect reliability, resilience and safety. We also sought their opinions on future technology options.

From time to time we commission Focus Groups to provide deeper insight into customer's thinking on issues such as pricing options, our tree trimming communications or Orion's approach to community sponsorships.

4.2.4 Connections survey

For the first time, we surveyed a range of customers and service providers about their experience of our connections process. Their feedback guided us to improve and streamline the online end to end process for connection. This innovation improved the efficiency of our connections service and delivered on asset management strategy focus areas of being close to our customers and key stakeholders, and enhancing operational excellence.

4.2.5 "Always-on" Contact Centre

We operate a 24/7 Customer Contact Centre which means we talk with our customers on a daily basis about the service they receive. Through around 3,000 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.

We talk with our customers on a daily basis about the service they receive.

4.2.6 Major customer engagement

All of our major customers are invited to at least two seminars a year 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.

4.2.7 Key stakeholder engagement

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

4.2.8 Customer engagement over major projects

We have also responded to increasing expectations on the part of the community 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. We also provide presentations to local Community Boards, local advertising and provide information via community social media channels.

4.2.9 Easy access to important information

Mass communication channels, trade shows, public exhibitions and social media are used to provide 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
- newspaper, magazine and radio advertising
- displays at trade shows for the farming community
- our website provides up to date information, real-time details of power outages and online customer service functionality
- Twitter updates

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 were aligned with and endorsed our focus on four key areas of our asset management strategy.

Reliability – What does a reliable service mean to you?

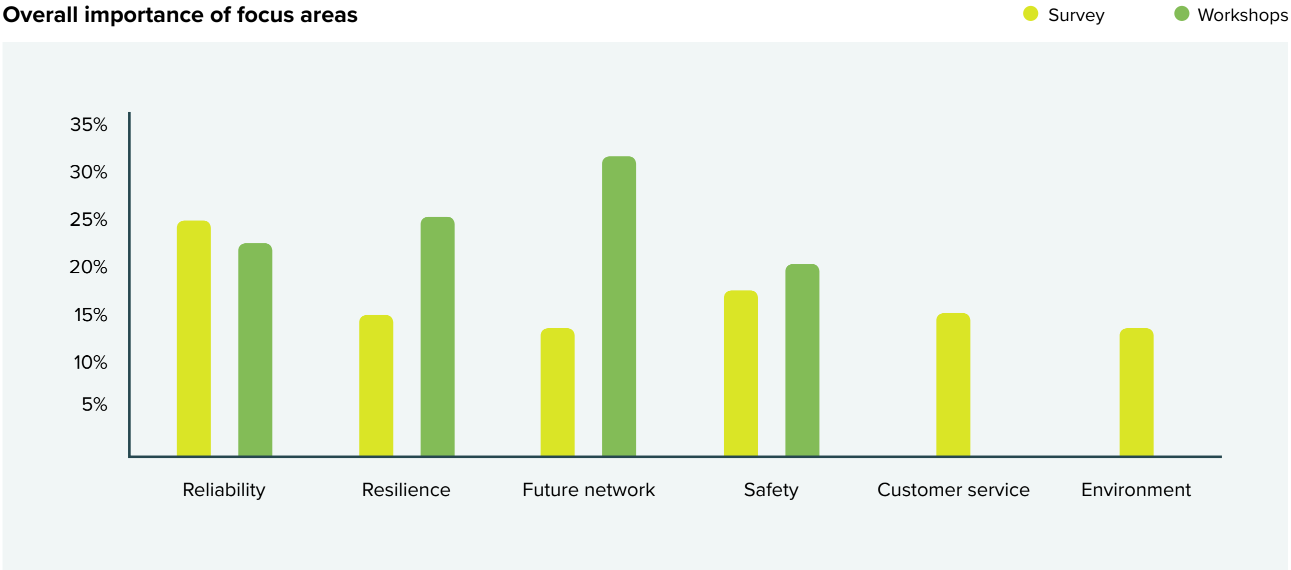
Resilience – How important is Orion's ability to be prepared for anything?

Future – How do you want Orion to prepare for future technology?

Safety – How would you want Orion to approach safety?

In our online survey we also asked customers to rate the relative importance of customer service and the environment.

Overall importance of focus areas



Reliability is the top priority for customers.

4.3.1 Reliability is the top priority for customers

Overall, being provided with a reliable service is the top priority for our customers. They 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.

Interestingly, customers in our workshops and our Customer Advisory Panel rated readiness for future technologies as being more important than a focus on reliability. This could be because they had the opportunity for a deeper discussion with Orion experts and were more engaged in conversations about what future technologies might offer them.

In our workshops customers also placed a priority on resilience. Again, the opportunity to discuss the meaning of resilience could have provided an increased appreciation of the importance of this focus area.

Customers consider reliability to be the core function of the electricity network and a survey of residential customers found 94% were satisfied with our performance in this area.

How satisfied are you with Orion's level of reliability?

* Total proportion that selected 'Satisfied' or 'Very satisfied' for each statement

We asked different groups of customers how satisfied they were with our current levels of reliability. This enabled us to identify areas where perceptions of reliability were below average, and areas where increased investment in the reliability of our network would be welcomed.

Customers want current levels of reliability to be maintained, if not improved – with shorter, and fewer outages, providing this is at no extra cost.

In 2017, we initiated a programme of network enhancements to improve reliability for the Lyttelton community and the above result shows Lyttelton residents were significantly more likely to be satisfied with reliability than in 2016 (74% compared to 53%). Our investment in laying a new 11kV supply cable through the Lyttelton tunnel is expected to further improve the reliability and resilience of power supply to this community and the Port.

In our "Powerful Conversations" workshops and Customer Advisory Panel sessions we sought a deeper understanding of the importance customers place on reliability.

In both forums, we were told that customers want current levels of reliability to be maintained, if not improved – with shorter, and fewer outages, providing this is at no extra cost. They also encouraged us to be more proactive and timely with communications around power outages, and that this would provide them with greater confidence around reliability.

Projects to improve reliability, particularly in rural areas and communications, are underway. See Section 4.4.

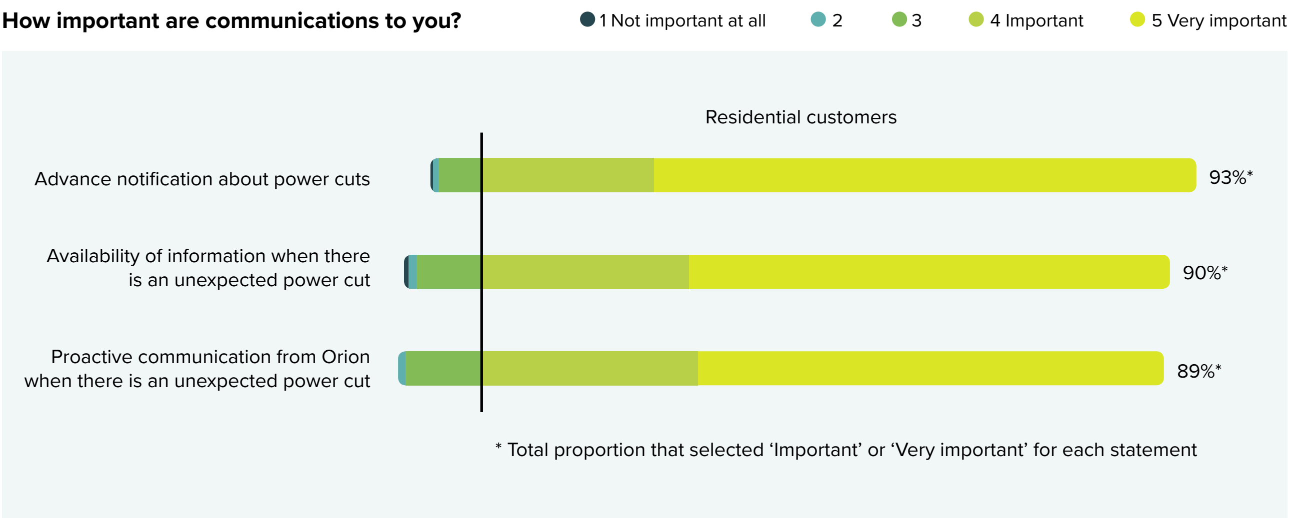
4.3 What our customers have told us continued

4.3.2 Communicating with customers is key

Proactive communication before or during power outages is very important to more than 70% of our residential customers. They want to know when the power is going to be off, and have certainty about when it will be restored.

If anything changes, they would like us to let them know promptly so they can plan their lives around it. This view was endorsed by our Customer Advisory Panel.

How important are communications to you?



4.3.3 Resilience is very important to customers

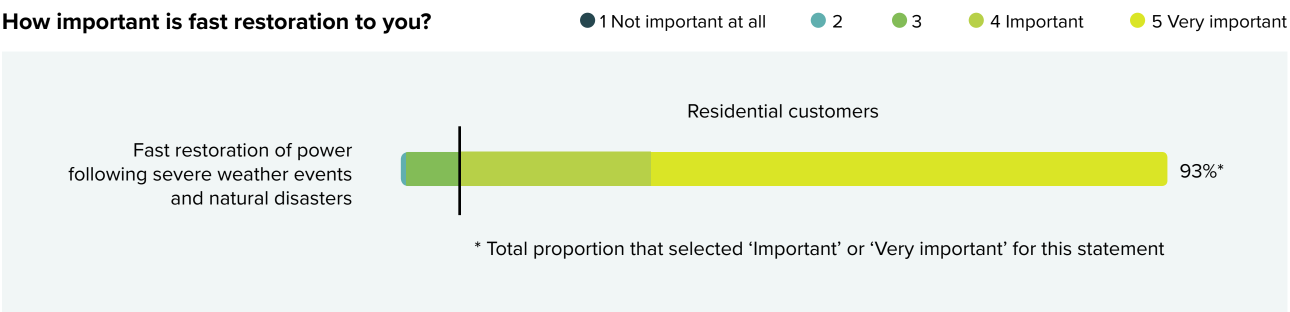
Our customers tell us Orion's investment in resilience represents good value for them. Customers have low tolerance for long outages, and want Orion to invest in resilience with this in mind.

Restoring power after a major event is very important. Almost 70% of residential customers stated that fast restoration of power following severe weather events and natural disasters is very important to them.

Our residential customers want power back on quickly, with a higher investment from their power bill. Most residents would prefer for a higher percentage of their power bill to go towards resilience in order to get power back on in a matter of days rather than weeks. See Section 4.4.

Almost 70% of residential customers stated that fast restoration of power following severe weather events and natural disasters is very important to them.

How important is fast restoration to you?



4.3.4 Future-proofing the network should involve 'leader' approaches

At both our "Powerful Conversations" workshops and Customer Advisory Panel sessions Orion was encouraged to have a strong focus on the future – to make sure our network was ready for customers to take advantage of new technologies.

This was reinforced in our online survey where more than 79% of residential customers agreed that Orion should take an innovative, proactive approach to preparing the network for the future. See Section 4.4.

How should Orion approach preparing for future technologies?

4.3.5 Managing safety risks should be common sense

Customers believe Orion should balance the costs and risks associated with safety issues when addressing them. They asked us to take a "common sense" approach to safety.

Around three quarters of residents agree that Orion should take either a low or moderate risk approach to addressing safety problems.

How should Orion approach safety?

4.3.6 Residents are price sensitive

While there were circumstances where some customers said they would pay more for increased network resilience, or more proactive communications, or to avoid certain aspects of outages, generally customers were sensitive to price increases and reluctant to see their power bill rise.

In our online survey, 60% of residential customers stated they would try to reduce the amount of electricity they use if their power bill were to increase by 10%.

Only 10% said that they would be able to afford a 10% increase without making any changes.

4.4 Turning listening into action

We recognise the importance of meaningful engagement with our customers. We endeavour to take on board what our customers have told us about where they want us to sit to best meet their expectations when we consider our future asset planning.

They have asked us to be pragmatic about our choices, and be prudent and efficient with our investment decisions. We are also mindful that we need to deliver value for money when we are making choices about our future plans. Our work programme includes a range of initiatives that translate what we have learned in our conversations with customers into action, in five key areas of focus in our asset management strategy. These include:

Improving reliability

- Continuing our Township Reliability Improvement programme
- Assessing our 11kV network architecture approach and its effects on reliability
- Increasing Orion's use of automated and enclosed network solutions
- New GXP in Region B to supply the western region of our network. For further detail see Table 6.6.2 project 931
- Establishing a cable link between McFaddens and Marshland. For further detail see Table 6.6.2 project 491

Communicating better with our customers

- Appointment of a General Manager, Customer and Stakeholder, to heighten our customer focus and performance. For further detail on structural changes see Section 8
- Driving a project to communicate proactively with more timely and accurate information about power outages, using channels our customers tell us are effective
- Implementing new protocols to engage with communities while we work on local infrastructure
- Refreshing our vegetation management communications
- Improving the efficiency of the process and provision of up to date information for customers as they progress through their connection experience

Investments in resilience

- Implementing a retirement strategy for Orion's existing 66kV oil filled cables. For further detail see Section 7.7.5
- Laying a new 11kV supply cable through the Lyttelton tunnel to improve resilience of power supply to this community and the Port
- New GXP in Region B to supply the western region of our network. For further detail see Table 6.6.2 project 931

Future-proofing the network

- Creating a new structure and positions to heighten our future focus, including roles to centre on Network Strategy and Transformation and Operations Improvement
- Gathering data on the LV network and upgrading PowerOn to include the LV model. For further detail see Section 6.2.2.1 and 6.6.7
- Customer feedback on trials of new energy management technology in test households
- Installing a new substation to support customer growth in Belfast. For further detail see Table 6.6.2 project 925
- Implementing Dunsandel substation upgrades to meet business development in this area. For further detail see Table 6.6.2 project 699
- Undertaking a Halswell transformer upgrade to provide increased supply to support subdivision growth. For further detail refer to Section 6 Table 6.6.2 project 919

Enhancing management of safety risks

- Continuing implementation of the enhanced pole management programme. For further detail see Section 7.5
- Reviewing and enhancing our safety in design process. For further detail see Section 5.6.3.1 and Figure 5.6.6
- Reviewing and implementing a more streamlined, customer safety-focused process for close approach consents
- Reviewing and implementing a more streamlined customer safety-focused process for temporary isolations

For a complete list of projects, see Section 6.6.

4.5 Measures

This section sets out how we measure our performance. Throughout our consultation with customers they have told us that a reliable supply of electricity is a top priority.

We also monitor our performance against a range of other service measures including efficiency, safety, environmental and legislative compliance. Our performance in these areas often provides a lead indicator of our performance prior to any change being apparent in our primary reliability targets.

Table 4.5.1 shows how our measures align with the asset management focus areas outlined in Section 2.6. The targets for these measures and our performance against targets are set out in Section 4.6 and 4.7 respectively. It is noted that for some service measures we have not set a specific target value. In those cases, we explain why we believe doing so would be counterproductive.

Table 4.5.1 Aligning performance measures and asset management focus areas

Measures	Asset management focus areas					
	Customers	Safe, Reliable, Resilient system	Health & Safety	Environment	Capability	Future Networks
Network reliability	✓	✓	✓	✓	✓	
Network restoration	✓	✓			✓	
Network capacity	✓					✓
Power quality		✓				✓
Safety		✓	✓			
Customer service	✓	✓				
Environmental				✓		
Efficiency	✓				✓	
Resiliency		✓			✓	

4.5.1 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 primary network reliability measures are applied as required by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012. These measures 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. Low voltage interruptions and those that originate in Transpower's transmission system are not included. Planned interruptions to carry out work on our network would normally account for approximately 15% of our SAIDI minutes and 5% of our SAIFI.

Extreme environmental events can have a major impact on the reliability of an electricity network and this can be seen in the actual SAIDI values in Figure 4.5.1. To moderate this impact, the current regulatory regime calculates a daily boundary value to cap the number of customer-minutes lost in the case of extreme events. Our annual network reliability limits and daily boundary values are currently set by the Commerce Commission under the Customised Price-quality Path (CPP) regime determined for us after the Christchurch earthquakes of 2010-2011.

These limits have run from FY15 through to FY19. Our FY20 limits will be the same as FY19 as stated in the Commerce Commission's Electricity Distribution Services DPP Determination 2015, see Section 4.6.2 for projected limits.

4.5 Measures continued

Our customers don't want us to continually improve network reliability as it increases prices. Also, 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.

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

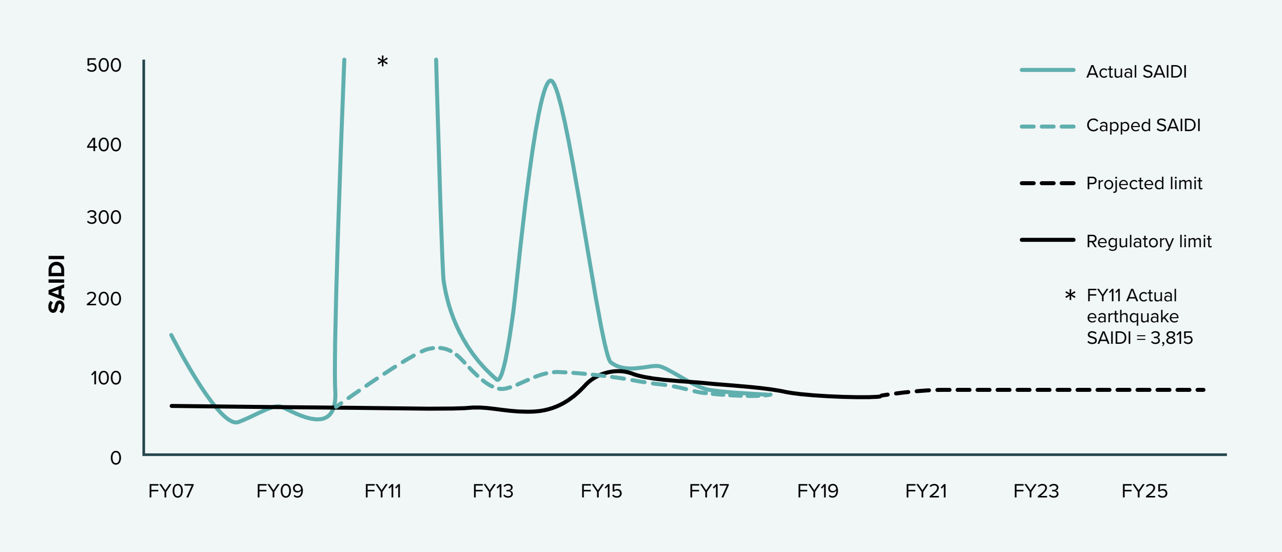
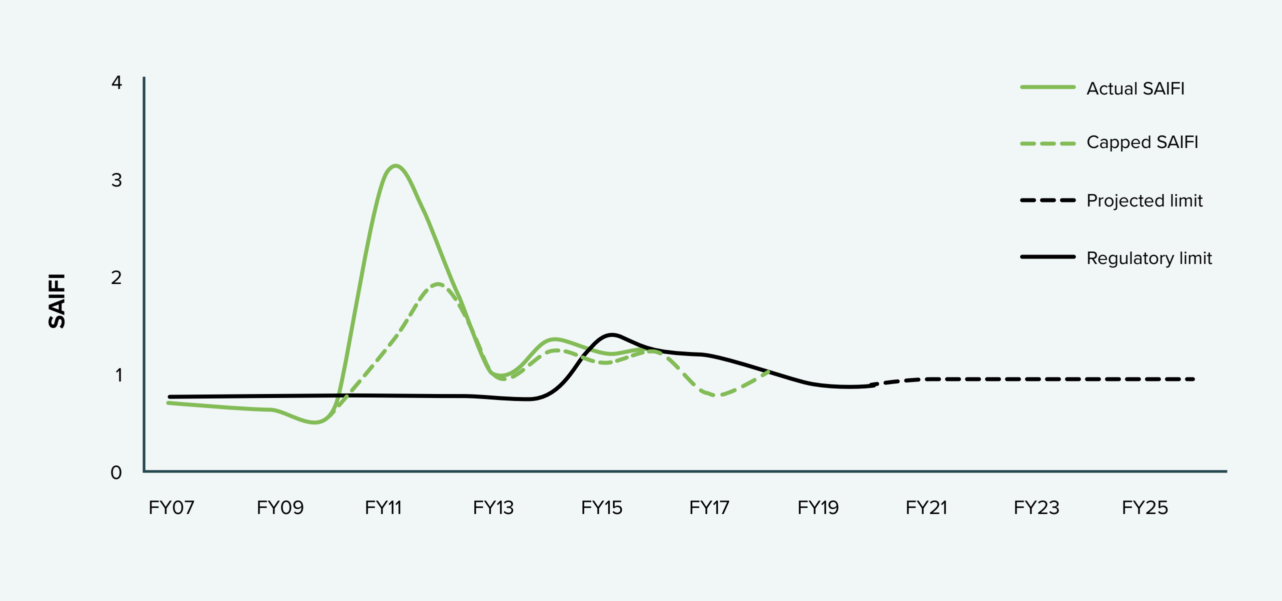


Figure 4.5.2 SAIFI 10 year history and 10 year target, including SAIFI forecast



4.5.2 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. Reasonable response times to effect a repair are set out in our contract work between us and our emergency service provider.

4.5.3 Network capacity

We define network capacity as the maximum capacity of the electricity network from the transmission lines as the source passing through our distribution grid and reaching our customers. Assets that determine our maximum capacity are at our GXPs and distribution lines. There is diversity of peak loads on the distribution lines which are sized for their individual peaks when other lines are out of service. Therefore the capacity constraint is the transformer capacity at the GXP. This is determined by total transformer capacity with the single largest transformer at the GXP being out of service i.e., firm capacity.

Trade-offs between price and electricity supply reliability are a constant focus for us. Generally, the more we spend, the more reliable our community's electricity supply becomes. However, the trade-off is the more we spend, the higher our prices become, as we need to recover our costs. We are committed to seeking our customers' views on the price/quality trade-off to ensure our network investment decisions reflect customer preferences.

We are committed to seeking our customers' views on the price/ quality trade-off to ensure our network investment decisions reflect customer preferences.

The demand group thresholds in our security of supply standard tend to err on the side of caution and generally provide a level of security that is slightly above the requirements of the average customer connection. Our analysis has also shown that it is appropriate to provide a slightly higher level of network security for the Christchurch CBD.

This approach ensures customers who place a high value on security of supply are reasonably represented in areas where a mix of customer types exists. Our security standard is detailed in Section 6 along with the proposed improvements to our network.

4.5.4 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** – fluctuations in voltage can affect customer's sensitive electronic equipment, reducing its performance
- **the level of harmonics or distortion of voltage of the power supply** - this affects customers' electrical equipment, causing humming and reduces the capacity of Orion's supply lines

We do not have total control over these attributes as we are reliant on the power quality supplied to us by Transpower. We contract with Transpower to provide an acceptable level of power quality performance at the GXPs, which is then passed on to our customers.

We have installed power quality measurement instruments throughout our distribution network as part of a long-term survey to determine the performance of our distribution network and how it changes over time.

4.5.4.1 Steady state voltage

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. 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.

4.5.4.2 Harmonics/distortion

The allowable level of harmonics or distortion of the power supply provided to customers is also covered by regulation. We investigate any distortion issues raised by customers and in most cases we find the customers' own equipment is responsible, for example, they may be using large electronic equipment such as modern rural irrigation systems. As part of our investigation we also look at whether other customers are affected. If others are affected, the customer is required to rectify the problem. We suggest suitable consultants who can rectify the issues, at the customer's cost.

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.

4.5.4.3 Working with customer's technical representative

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. In many cases the customer's technical representative can also contribute to misunderstandings which fall short of good sound resolution. Contributing factors to what can be a difficult path to resolution can be service provider time constraints when every hour has to be productive, or suggestions a product failure could have been avoided if the customer's equipment was protected or upgraded, and the possibility of selling a preferred product to resolve a perceived problem.

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.

4.5.4.4 Monitoring performance

An important part of 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.

We take all practical steps to minimise the risk of harm to the public, our service providers and our people.

4.5.5 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 objectives are to:

- keep the public and our people and service providers safe at all times when working on and/or near our assets
- provide safe plant and systems to always ensure worker and public safety
- ensure compliance with legislative requirements and current industry standards
- provide safety information, instruction, training and supervision to employees and service providers
- provide support and assistance to employees
- set annual goals and objectives, and review the effectiveness of policies and procedures
- take all practicable steps to identify and then either eliminate or minimise hazards

Further information on these objectives is available in our Statement of Intent and our performance against them is detailed in our Annual Report. Our target of no serious safety events or accidents is the only prudent target we could have to measure safety.

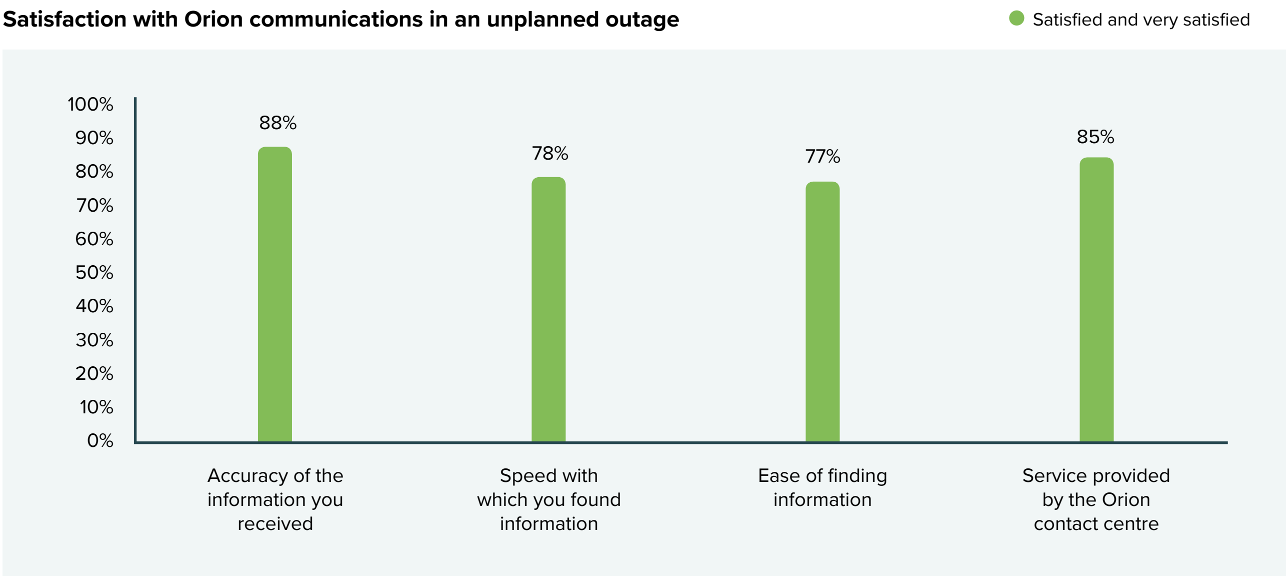
4.5.6 Customer service

We operate a 24/7 contact centre. Following an interruption to their electricity supply, our customers tell us it is important to give them accurate information about when the power will be restored. In our 2017 annual telephone survey of residential customers, 21% said they would contact Orion in the event of a power outage, 18% said they would look on our website. Satisfaction among those who had contacted Orion seeking information was high.

We are currently collaborating with our industry peers to develop industry wide standards for setting and measuring customer service targets, in addition to developing our own organisation specific targets.

Following an interruption to their electricity supply, our customers tell us it is important to give them accurate information about when the power will be restored.

Satisfaction with Orion communications in an unplanned outage



4.5.7 Environmental

We are committed to being environmentally responsible. This is consistent with our Vision and Values. We have established a number of environmental sustainability policies that are published on our website. These policies are reviewed annually. Further information on each of these policies is available in our Statement of Intent which is also on our website.

The environmental measures related to the operation of our network are:

- the amount of SF_6 gas lost into the atmosphere – as a percentage of the total volume in use on our network
- the number of oil spills that are not contained by our oil containment facilities or mitigation procedures

We are committed to being environmentally responsible.

4.5.7.1 SF_6 gas lost

Sulfur hexafluoride (SF_6) is a potent greenhouse gas that is used as an interruption medium for switchgear. We are committed to minimising Orion's SF_6 emissions and carefully monitor and report losses. We have set ourselves a target of less than 0.8% annual loss to the atmosphere of the insulating gas SF_6, based on a percentage of the total volume of the gas in use on our network. This has been achieved over the last five years.

Our target exceeds the compliance level of 1%, which is the compliance level set by the Ministry for the Environment to comply with the "Memorandum of Understanding relating to Management of Emissions of Sulphur Hexafluoride (SF_6) to the Atmosphere".

We are committed to minimising Orion's SF_6 emissions and carefully monitor and report losses.

4.5.7.2 Oil spill

In respect to oil spills, 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.

4.5.8 Efficiency

4.5.8.1 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. 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)

4.5.8.2 Capacity utilisation ratio

This ratio measures the utilisation of transformers installed on our network. It is calculated as the maximum demand experienced on the network divided by the distribution transformer capacity on the network.

Our management process aims to ensure maximum economic efficiency by ensuring good design and lifecycle management practices. If we specifically target levels of capacity utilisation, there could be an incentive to design inefficiently, for example to install long lengths of low voltage distribution or uneconomically replace transformers early in their lifecycle due to shifts in area load profiles. For this reason, we do not have a specific target.

4.5.8.3 Load factor

The measure of annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in any given year. We always seek to optimise load factor as this indicates better utilisation of capacity in the network.

Our forecast load factor band is shown in Section 6.4.2.

4.5.8.4 Energy loss

All electricity networks have energy losses caused mainly by heating of lines, cables and transformers. Electrical losses are natural phenomena that cannot be avoided completely and to allow for those losses, retailers purchase more energy than is delivered to their customers.

Electrical losses are the difference between energy volumes entering our network, mainly at Transpower GXPs, and the energy volumes leaving our network at customer connections. We estimate that these losses are around 5% with a margin of error of +/- 1%. Significant deviations from this value exist in some parts of our network, for example, when we compare urban areas against rural areas.

When considering losses in network design and asset purchase, we do not aim for a target percentage of loss. Instead the lifetime annual cost of losses is converted to a net present capital value which can be added to the capital value of the asset concerned. This approach provides the optimal economic level of losses in a balanced way.

4.5.9 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.

Currently, we are investigating methods for setting and measuring resiliency standards/targets that capture the preparedness and response of our people, systems and network.

A more resilient network will limit the number of customers affected after major events.

4.6 Targets

We endeavour to provide a level of service that meets the expectations of our customers in the long term. We also recognise their differing requirements and work hard to ensure that, as far as practical, all customers are satisfied with the service levels we provide and that no one party is unfairly advantaged or disadvantaged. Assumptions for setting service level targets are described in Section 2.13.

In setting our service level targets we believe we have achieved an appropriate balance between legislative, regulatory and stakeholder requirements and customer expectations.

Our service level targets are based on a balance of:

- customer and stakeholder consultation
- health and safety considerations
- regulatory requirements
- international best practice
- past practice

This section describes our targets set in line with our asset management strategy for all the measures discussed in Section 4.5.

4.6.1 Current year

For FY18, our service level targets, performance measures and how we measure performance are outlined in Table 4.6.1.

4.6 Targets continued

Table 4.6.1 Service descriptions, targets and measures for current year (FY19)

Service class	Service measure	FY18 targets	Performance measure	Measurement procedure
Network reliability	SAIDI – system average interruption duration index	< 73.4	Average minutes lost per customer per annum for all interruptions (planned and unplanned)	Tracking of all interruptions to our network (process audited annually)
	SAIFI – system average interruption frequency index	< 0.87	Average number of times a customer's supply is interrupted per annum for all interruptions (planned and unplanned)	All 400V faults are excluded and HV faults <1 min in duration are excluded
Network restoration	Unplanned interruptions restored within 3 hours	> 60%	% of total number of unplanned interruptions where the last customer is restored in three hours or less	Capped to daily boundary values for any extreme event days as per CPP requirements
Network capacity	Overall network capacity at GXP	Load < 100% of firm capacity	Peak demand does not exceed firm capacity at GXP	
	Delivering reasonable level	To meet our security standard	Any gaps identified against our security standard	
Power quality	Steady state level of voltage	< 80	Voltage complaints (proven)	Target is set to no more than one per 2,500 customers
	Level of harmonics or distortion	< 4	Harmonics (wave form) complaints (proven)	Checks performed using a harmonic analyser. Target is et to be more than one per 50,000 customers
Safety	Safety of employees and service providers	Zero	Serious safety events	Accident/incident reports
	Safety of public	Zero	Number of accidents involving members of the public (excluding car v pole accidents)	Accident/incident reports
Customer service			Under development	
Environment	SF_6 gas lost	< 1% loss	Gas lost expressed as a % of the total contained in our network equipment	
	Oil spilt	Zero	Oil spills not contained	
Efficiency	Economic efficiency	We do not have a specific target	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)	
	Capacity utilisation ratio	Although we monitor this ratio, we do not have a specific target	Ratio measures the utilisation of transformers installed on our network	
	Load factor	Although we monitor this measure, we do not have a specific target	The average load that passes through a network divided by the maximum load experienced in any given year	
	Energy loss	We do not have a specific target	Electrical losses are the difference between energy volumes entering our network GXPs and the energy volumes leaving our network at customer connections	
Resiliency			Under development	

4.6 Targets continued

4.6.2 Future years

Our service level targets and how these targets are measured are outlined in Table 4.6.2. 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.

As we currently do not have reliability limits for FY21 to FY25 from the Commerce Commission, we have undertaken our own assessment of our proposed targets. These targets reflect what we believe is reasonably practicable and in the long-term interests of our customers and community, given the state of our network, the weather environment and our wider context.

The targets are based on our actual performance in recent benign and non-benign weather years and are calibrated against our detailed bottom up reliability analysis. This is also in line with customer expectations based on our engagement over the past two years.

Table 4.6.2 Service descriptions, targets and measures for future years

Service Class	Service Measure	Target								
		FY20	**FY21**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**
Network reliability	SAIDI – system average interruption duration index	< 73.4	< 84	< 84	< 84	< 84	< 84	-	-	-
	SAIFI – system average interruption frequency index	< 0.87	< 1.09	< 1.09	< 1.09	< 1.09	< 1.09	-	-	-
Network restoration	Unplanned interruptions restored within three hours	> 60%								
Network capacity	Overall network capacity at GXP	Load < 100% of firm capacity								
	Delivering reasonable levels of network security	To meet our security standard								
Power quality	Steady state level of voltage	< 80								
	Level of harmonics or distortion	< 4								
Safety	Safety of employees and service providers	Zero								
	Safety of public	Zero								
Customer service	Under development	Under development								
Environment	SF_6 gas lost	< 0.8% loss								
	Oil split	Zero spills								
Efficiency	Economic efficiency	No target								
	Capacity utilisation ratio	No target								
	Load factor	No target								
	Energy loss	No target								
Resiliency	Under development	Under development								

4.7 Performance

We review our performance against targets stated in our previous AMP. These targets may be actual values or a declaration to carry out particular maintenance or reduce risk. This section also includes a discussion on some current and future initiatives along with a reliability gap analysis.

4.7.1 Network reliability

SAIDI and SAIFI levels[1] are averaged across the network which reflects the average customer experience, but does not reflect the experience of each individual customer. To help mitigate this issue we have started analysing the number of unplanned interruptions at the distribution transformer level for our township customers. This information allows us to see which customers are more adversely affected so we can target our network improvement expenditure to improve the service to those customers.

Apart from the township performance improvement, analysis of our fault causes has lead us to focus on a number of particular work streams to support reliability outcomes. These are designed to:

- increase our focus on analysing cause trends for overhead line faults
- continue development of condition based risk assessment
- improve the comprehensiveness of data capture
- consider additional mitigation for when significant load is temporarily on N security

Table 4.7.1 shows our FY18 SAIDI and SAIFI results which are consistent with our targets and under the Commerce Commission's CPP reliability limit. We met our targets for FY18 for network reliability.

Table 4.7.1 Network reliability results for FY18 and last five-year average

Category	FY18 target	FY18 result[2]	FY13-FY17 average	FY18 CPP reliability limit
SAIDI	< 82.4	79	91	82.4
SAIFI	< 1.02	1.00	1.06	1.02
Faults restored within 3 hours (%)	> 60%	67%	65%	–
Subtransmission lines faults per 100km[3]	3.7	2.7	4.2	–
Subtransmission cables faults per 100km[3]	0.8	0.8	1.6	–
Distribution lines faults per 100km[3]	18.0	17.7	18.8	–
Distribution cables faults per 100km[3]	2.8	2.5	2.9	–

[1] One-off major events such as bad weather or earthquakes can heavily influence SAIDI and SAIFI results in any given year

[2] Major event daily limits applied in accordance with CPP

[3] As per Commerce Commission disclosure schedule 10(v)

4.7.1.1 Comparison by cause and asset class

Figure 4.7.1 shows a further breakdown of SAIDI and SAIFI by asset class and a five-year average comparison graph is shown in Figure 4.7.2. 11kV overhead 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. FY18 data of interest includes:

- 33kV joint failures have continued rather than reducing to zero as expected. Vulnerable joints are being identified and a replacement programme instigated
- Planned 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
- Bromley 66kV disconnector event was significant but not high enough to reach the capping limit. It caused loss of supply to three zone substations
- Springston 66/33kV transformer tap changer failure gave elevated SAIDI and SAIFI to the transformer category
- Noticeably fewer 11kV cable joint failures

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

Figure 4.7.1 FY18 SAIDI and SAIFI by asset class and by cause

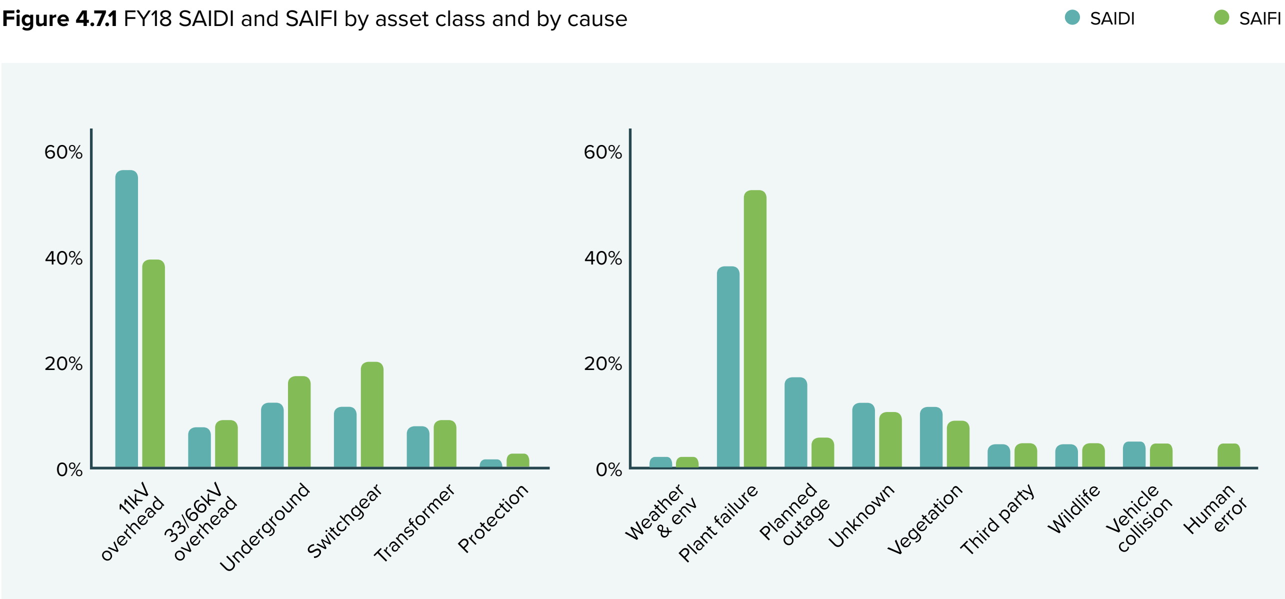
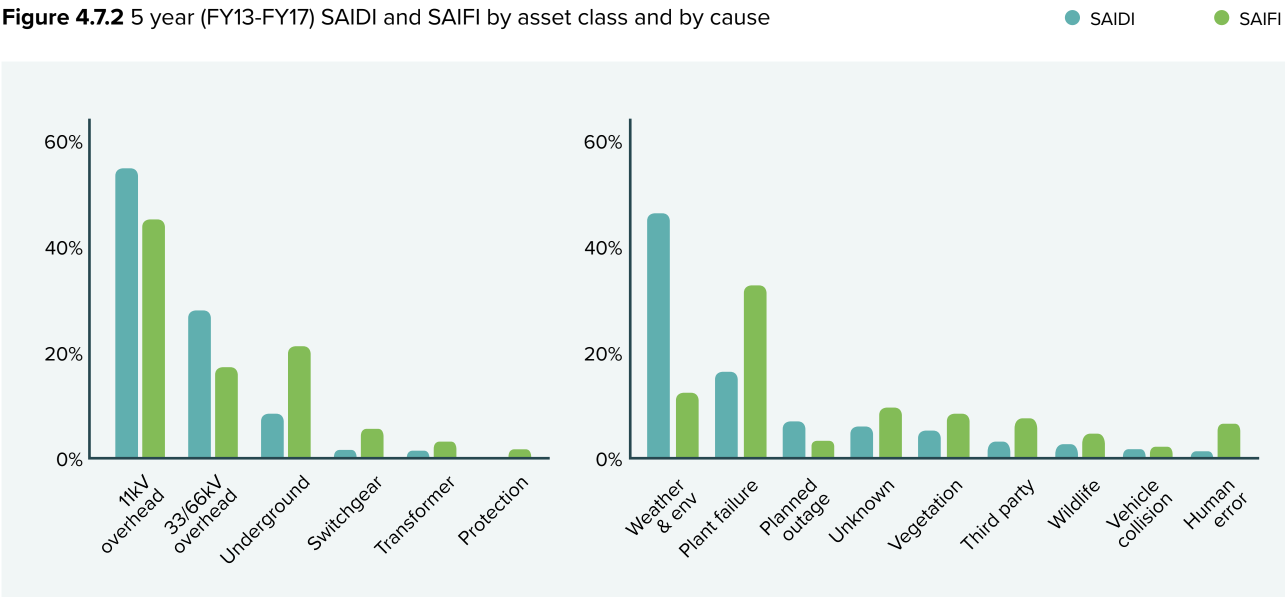


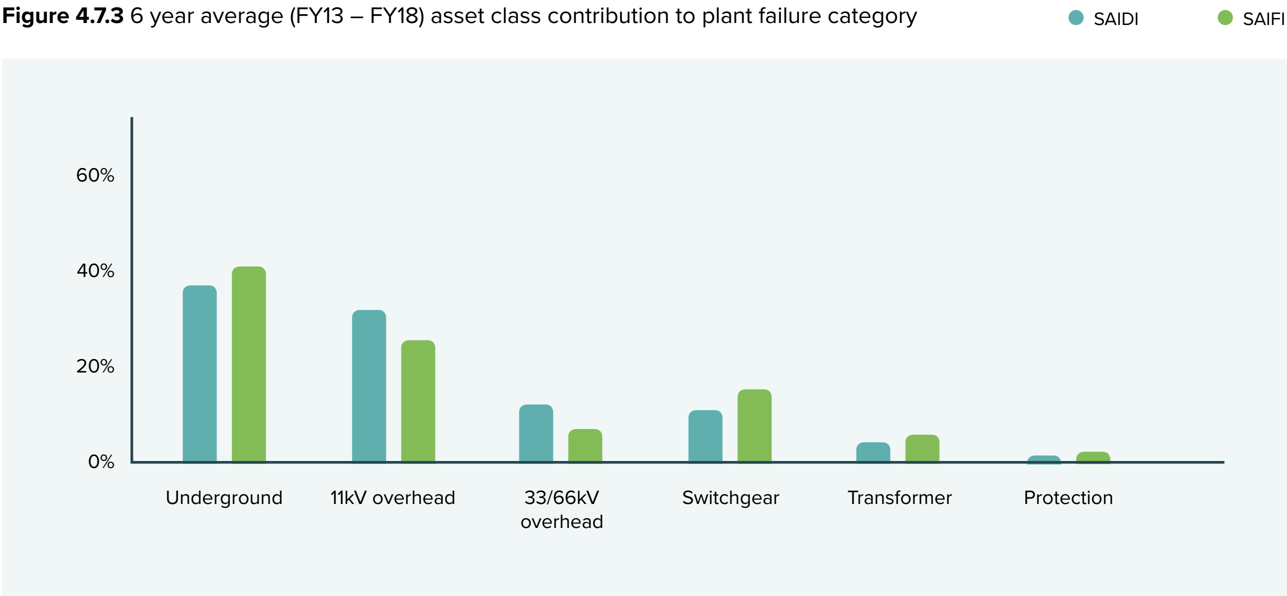
Figure 4.7.2 5 year (FY13-FY17) SAIDI and SAIFI by asset class and by cause



4.7.1.2 Cause of failure

As shown in Figure 4.7.3, 11kV overhead and underground contributes to 70% of SAIDI and 70% SAIFI. The root cause for these two asset classes are described below.

Figure 4.7.3 6 year average (FY13 – FY18) asset class contribution to plant failure category



Underground

The majority of underground impact is 11kV cable failure which is broken down to failures of 50% joint, 40% run of the cable and 10% termination. Based on the field experience of our service provider, we are still experiencing joint failures in the red zone areas. Setting aside the latent impact of the earthquake, and based on the data available, 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

There have been eight 33kV joint failures, mostly in the last four years. In both FY15 and in FY18, two joints failed on the same day. Most of the failures were attributed to poor jointing technique or methods. Some vulnerable joints were identified in FY18 and load is being managed to reduce stress on these joints.

11kV Overhead

11kV insulator failure has occurred due to earthquake, asset lifecycle and GFN compensation. The intense vibration of the earthquake caused stress on the insulators compounded by several extreme wind storms, especially on the porcelain – on pin type insulators. Close to 50% of insulators are around 50 to 60 years old and are close to their end of life. Each time the GFN compensates, it places the other two phases under increased stress due to increased voltage which could lead to an increased failure rate.

70% of the 11kV conductor failure occurs at the tail end; the dissimilar-metal (brass and aluminium) joint between the overhead conductor and the HV fuse holder fails, and the overhead conductor connected to the binder / insulator is loose. Deteriorated joints are the primary cause of failure rather than the conductor itself. Poor jointing techniques and corrosion are the main contributors to this, especially in coastal areas.

The performance of the network could be greatly improved if the network was undergrounded. However, to underground Orion's entire overhead network would cost in the order of $3 billion dollars and only benefit 10% of our customers. This would be off-set by a reduction in operational expenditure in the order of $15 million per year.

Currently the majority of undergrounding of our existing overhead network is driven by third parties requiring our assets to be relocated. The agencies involved include roading authorities, district councils, developers and private property owners. They generally require the relocated assets to be undergrounded for safety or visual amenity benefits.

We may underground if we are undertaking works where with minimal additional costs we can achieve supply performance or safety benefits for the community.

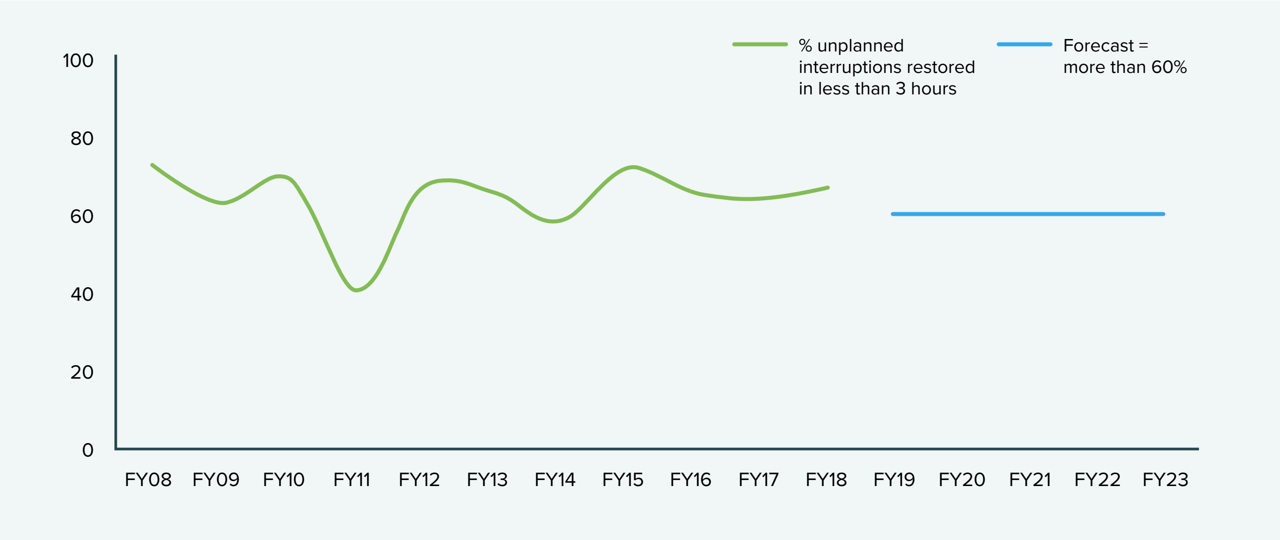
4.7.2 Network restoration

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.

The period between FY10-FY14 in Figure 4.7.4 had a number of such events with earthquakes, snow storms and very high wind events which had an impact on the restoration times.

With improvements in fault indication and the installation of a greater number of remotely controlled devices across the network, we expect the trend to continue to improve over time as we are able to more quickly locate faults and restore supply. These improvements will not only speed up the restoration time in rural areas during storm events, but also for significant urban faults which can affect a larger number of customers. We have met our target for FY18.

Figure 4.7.4 Unplanned interruptions - % restored in under three hours



4.7.3 Network capacity

Electricity is transmitted from the transmission lines to various GXP locations, then through our network before reaching our customers. With the distribution lines sized to cover line outages and the diversity of peak loads, our network capacity is constrained by the GXP firm capacity. Table 4.7.2 shows the GXP capacity and network demand.

Table 4.7.2 GXP capacity and network demand

GXP Location	Security standard class	GXP Firm Capacity	Network Demand
Bromley 66kV	A1	210	133 (63%)
Islington 33kV	B1	107	71 (66%)
Orion Islington 66kV	A1	494	372 (75%)
Hororata 33kV	C1	23	Update later
Kimberley 66kV, Hororata (66 & 33kV)	C1	70*	Update later

* Assumes full generating capacity available from Coleridge. Can be limited to 40MW capacity when Coleridge is not generating or providing reactive support

4.7.4 Power quality

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 4.7.3, 'proven' means that the non-complying voltage or harmonic originated in our network. We have met our targets for FY18.

Table 4.7.3 Network power quality performance against target

Category	Measure	Target	Achieved FY18	Performance indicator	Measurement procedure
Power quality	Voltage complaints (proven)	< 80	17	Non compliances per annum	Tracking of all enquiries
	Harmonics (wave form) complaints (proven)	< 4	2	Non compliances per annum	Checks performed using a harmonic analyser

4.7.5 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.

In March 2018, our service provider was undertaking some maintenance work at Larcomb Zone Substation and on closing a circuit breaker a fire occurred within a kiosk located on the site. Fire and Emergency New Zealand attended and WorkSafe was notified. As a result of this incident, we have not met our targets for FY18 as shown in Table 4.7.4.

Our asset maintenance and replacement programmes are fundamental to ensuring safety targets relating to assets are met in the future.

Table 4.7.4 Personal safety – performance results

Key asset management driver	Measure	Target	Achieved FY18	Performance measure	Measurement procedure
Personal safety	Safety of employees	0	0	Notifiable injury, incident or illness	Accident/incident reports
	Safety of our service providers	0	1	Notifiable injury, incident or illness	
	Safety of public	0	0	Number of accidents involving members of the public (excluding car vs pole accidents	

4.7.6 Customer service

We are currently developing methods for setting and measuring customer service targets as mentioned in Section 4.5.6.

4.7.7 Environmental

We have a limited number of 11kV circuit breakers that use SF_6 as the interruption medium. It is now our practice to wherever economically feasible, 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. For more information, see Section 7.10. Table 4.7.5 shows we have met our SF_6 targets for FY18.

Table 4.7.5 Environmental responsibility – performance results

Key asset management driver	Measure	Target	Achieved FY18	Performance measure	Measurement procedure
Environmental responsibility	SF_6 gas lost	< 0.8% loss	0.07% loss	Identification of environmental problems	Environmental spill/loss report
	Oil spills (uncontained)	0	0		

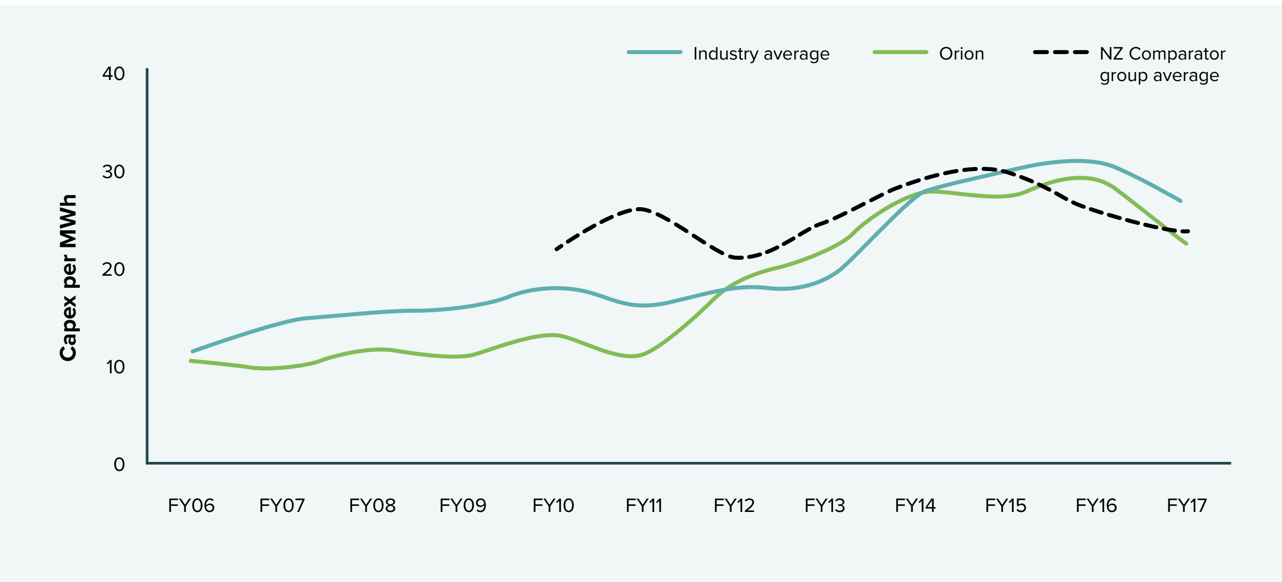
4.7.8 Efficiency

4.7.8.1 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. 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.

Figure 4.7.5 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. All three parameters show an easing trend of capital expenditure between FY14 and FY16. 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 4.7.5 Comparing Capex per MWh and industry performance



4.7 Performance continued

Figure 4.7.6 compares our performance for opex per MWh with both average industry performance and a subset NZ comparator grouping. 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 aligned with that of both the industry average and the subset NZ comparator grouping preceding FY13.

All three parameters show a gradual ramping trend of operating expenditure from FY13. This is reflected in this AMP as we move into a period of asset management continual improvement linked closely to customer expectations while maintaining our service provider workload at sustainable levels that match our resource availability.

Figure 4.7.6 Comparing Opex per MWh and industry performance

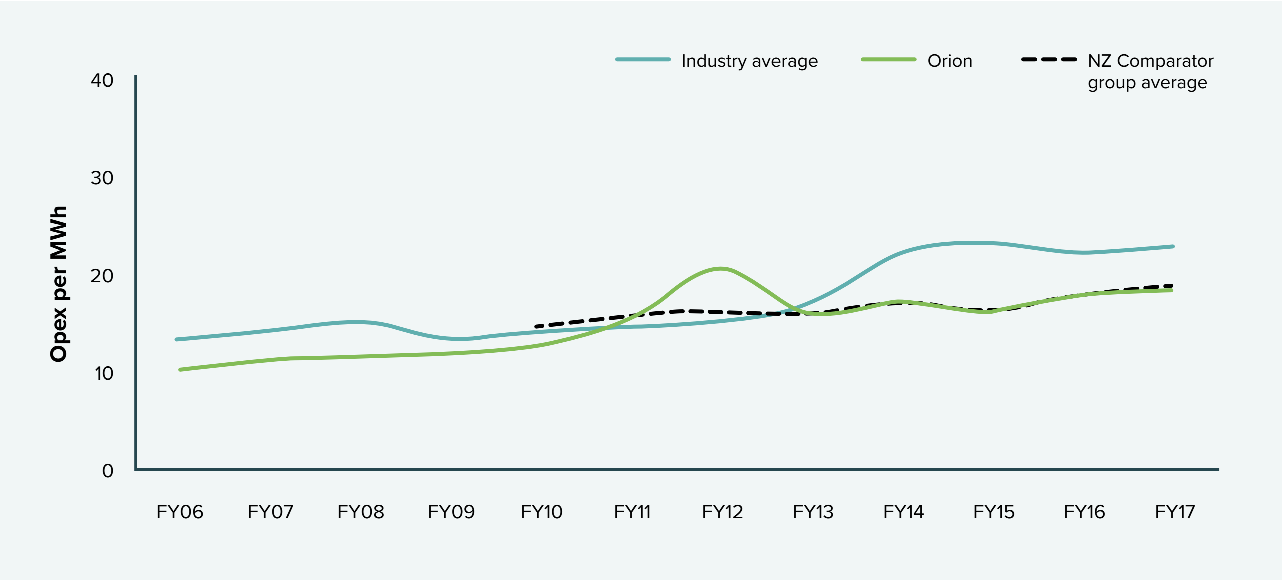
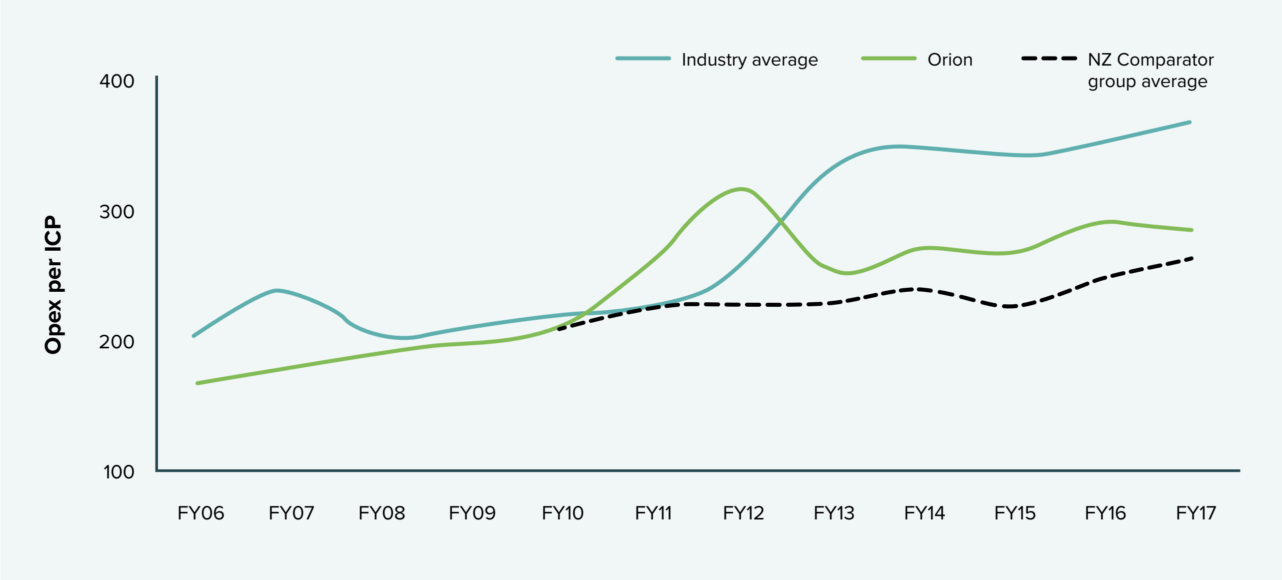


Figure 4.7.7 compares our performance for opex per ICP with both average industry performance and a subset NZ comparator grouping. A short term increase in our opex expenditure, combined with a reduction in connected ICPs immediately following the 2010 and 2011 Canterbury earthquakes, is clearly visible 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.

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 gradual ramping trend of operating expenditure from FY13. Our ICP base has increased from an average number of ICPs in FY13 of 192,146 to 196,421 in FY17 i.e., our customer base continues to increase gradually bringing us into closer alignment with the subset NZ comparator grouping at FY17.

Figure 4.7.7 Comparing Opex per ICP and industry performance



Overall we are proud of our performance during a significant period of post-earthquake recovery. Feedback from our customer engagement tells us we are meeting our customers' service expectations. We are focused on supporting our region's growth and meeting our customers' expectations for the future.

4.7.8.2 Capacity utilisation ratio

This ratio measures the utilisation of transformers in our network. It is calculated as the maximum demand experienced on our network divided by the network distribution transformer capacity.

We are focused on supporting our region's growth and meeting our customers' expectations for the future.

Table 4.7.6 Capacity utilisation results for FY18 and five year average FY13-FY17

Category	Target	Achieved FY18	Achieved 5-Year Average
Capacity utilisation (%)	No target set	27.2%	28.0%

4.7.8.3 Load factor

Annual load factor is calculated as the average load that passes through our network divided by the maximum load experienced in a given year. We always seek to optimise load factor as this indicates better utilisation of capacity in the network.

Load factor has trended upwards from 1990-2009 by ~0.6% per annum, and has since levelled off. The impact on load factor from the anticipated reduction of irrigation load due to Central Plains Water scheme is expected to be partially offset by the Central City rebuild. This is expected to reduce load factor in the short term. Longer term load factor will level out if battery storage takes the growth out of winter peak demand. See Section 6 for a load factor chart.

Table 4.7.7 Load factor results for FY18 and five year average FY13-FY17

Category	Target	Achieved FY18	Achieved 5-Year Average
Load factor (%)	No target set	59.6%	61.0%

4.7.8.4 Energy loss

We use loss ratio for the purposes of disclosure which is calculated based on electricity losses divided by electricity entering the system for supply to customers' connection (GWh).

Table 4.7.8 Electricity loss ratio results for FY18 and five year average FY13-FY17

Category	Target	Achieved FY18	Achieved 5-Year Average
Losses (%)	No target set	< 5% estimated	< 5% estimated

Other sources of loss

Apart from losses due to our assets, we can identify three categories that would contribute to network loss that is not possible to measure:

- **Internal usage by Orion** – all our major facilities, such as our five year old, energy efficient administration office, are metered and we purchase electricity from a retailer like any normal customer. However, many unmetered supplies are needed at our substations to operate equipment that is integral to a safe and reliable network. The annual volume of energy involved is estimated at 0.1% of total energy volume across our network.
- **Unmetered supplies** – substantial volumes, such as supply to street and traffic lights, are estimated and included with retail sales. Other miscellaneous outlets, such as those at parks, contribute towards losses at insignificant levels.
- **Theft** – theft may significantly contribute towards losses, although actual volume is unknown. Electricity retailers are responsible for integrity of metering at connections and for reading meters.

4.7.9 Resiliency

We are currently not measuring the performance of resiliency. As mentioned in Section 4.5.9, we are developing methods for setting and measuring resiliency standards/ targets that capture the preparedness and response of our people, systems and network.

8,000

Square kilometres network coverage

11,350

Kilometres of lines and cables

50

Zone substations

350

Major customers with loads from 0.2MVA

90,000

Orion power poles

11,500

Distribution substations

5

About our network

Photo: Orion recently upgraded capacity at its zone substation in Dunsandel to power local dairy processor Synlait's installation of a new electrode boiler. The new boiler is expected to save 13,714 tonnes of CO2e per year, or the equivalent of removing 5,300 cars from the road per annum.

Contents

5.1 Introduction

This section presents an overview of Orion's network architecture, the current design and future development 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	68%
Bromley	29%
Hororata	2%
Coleridge, Arthur's Pass, Castle Hill and Kimberley	1%

The Islington GXP supplies 68% of our customers. As the number of customers reliant on the Islington GXP grows, we will work the Transpower to overcome the risks associated with being 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.

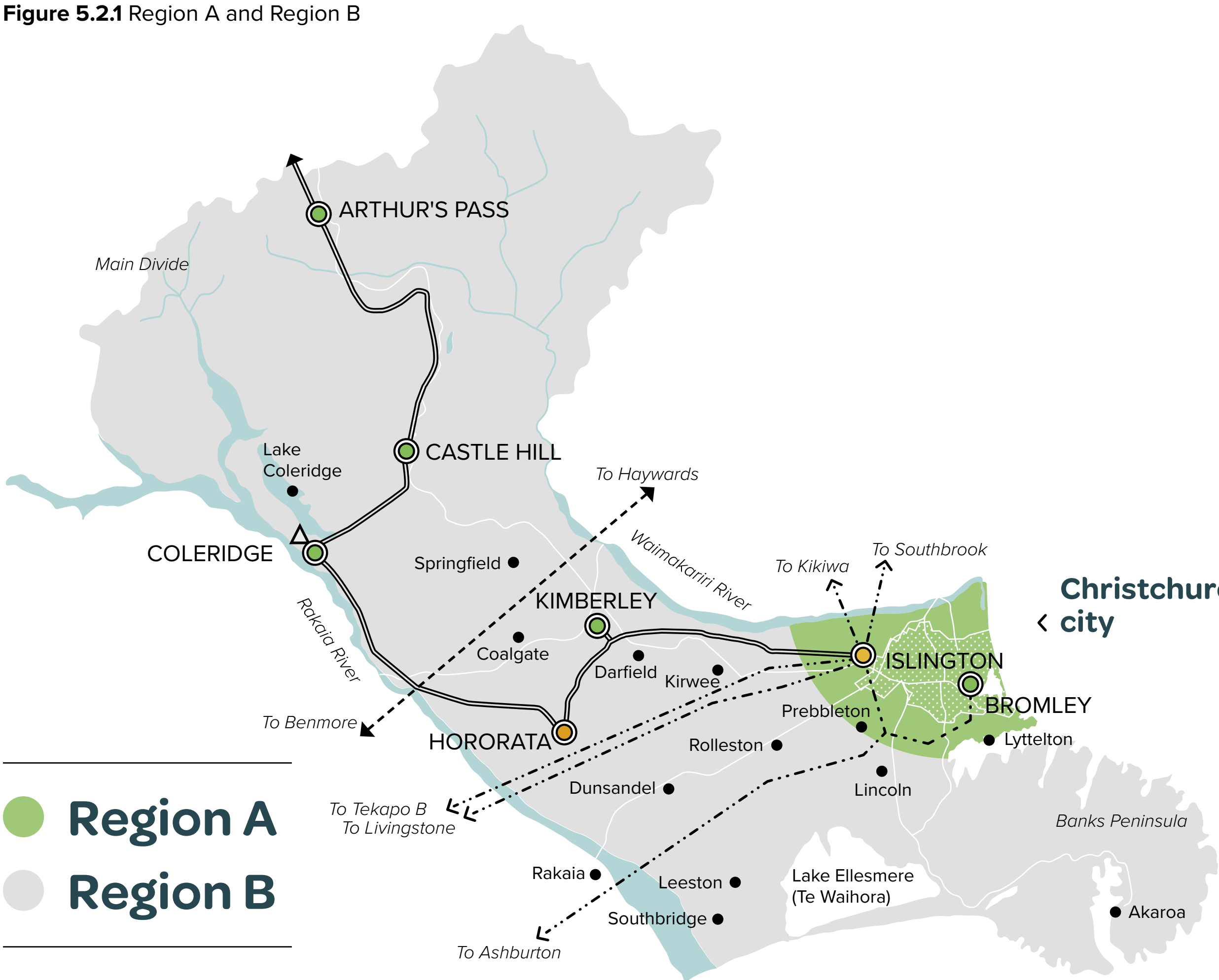
For planning purposes, our network is divided into two regions:

Region A – Christchurch city and outer suburbs

Region B – Banks Peninsula, Selwyn district townships and rural areas

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

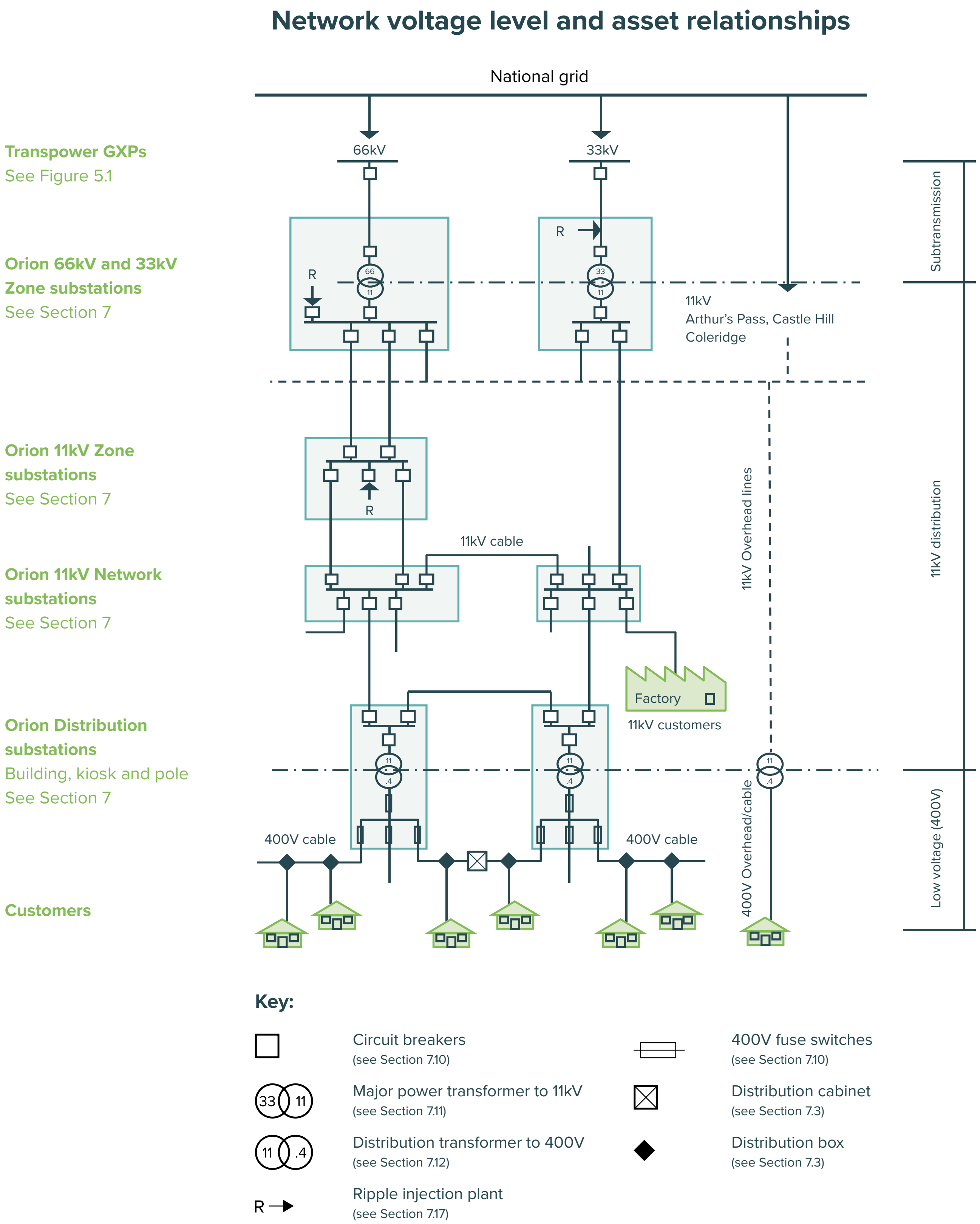
Islington GXP also supplies a large part of the Region B network including Banks Peninsula and the Rolleston and Lincoln townships. Hororata and Kimberley GXPs supply a significant proportion of the summer irrigation load and milk processing area. These two GXPs have a connection to the double circuit 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 88% of our customers are in Region A with the remaining 12% in Region B. Figure 5.3.1 shows an overview of our network and Table 5.3.1 shows the asset quantities managed by us.

Figure 5.3.1 Network voltage level and asset relationships



5.3 Network architecture continued

Table 5.3.1 Our electricity network asset quantities

Category	Description	31 March 2018
Total network	Lines and cables (km)	15,825
	Zone substations	50
	Network substations	216
	Distribution substations	11,483
	Poles	89,243
Overhead lines (km)	66kV	244
	33kV	276
	11kV	3,189
	400V	1,778
	Street lighting	912
Underground cables (km)	66kV	91
	33kV	39
	11kV	2,648
	400V	3,087
	Street lighting	2,525
	Communication	1,036
	Total cables	9,426
Zone substations	66kV	27
	33kV	19
	11kV	5
Distribution substations	Building	251
	Ground mounted	4,822
	Pole mounted	6,416
Embedded generation	Greater than 1MW	6
Major business customers	Loads from 0.2MVA	350

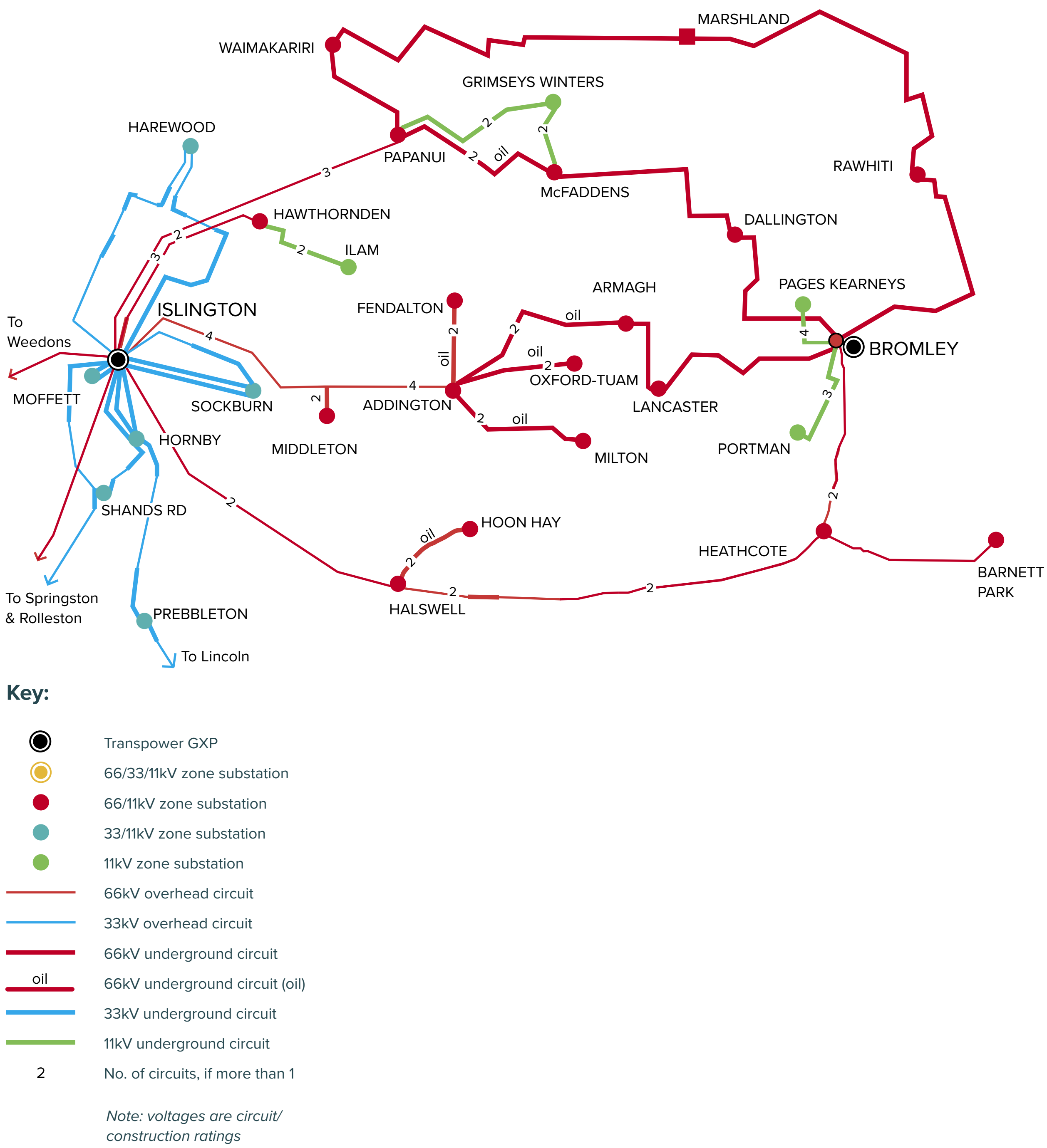
5.3.1 Region A subtransmission

Our Region A subtransmission network (Figure 5.3.2) consists of both a 66kV and a 33kV subtransmission system. Our 66kV system supplies 18 zone substations in and around Christchurch city and is supplied from Transpower's GXPs at Bromley and Islington. Our 33kV system supplies another six zone substations in the western part of Christchurch and is supplied from Transpower's Islington GXP. A further five zone substations in the area take supply at 11kV from our 66kV zone substations.

The zone substations supply a network of 11kV cables connected to 201 network substations. These network substations in turn supply over 4,000 distribution substations on a secondary 11kV cable network. The interconnected nature of the secondary network means that supply can be switched, allowing restoration of power to most customers within a relatively short time.

The low voltage (400V) system to which most of our customers are connected is supplied from these distribution substations. For future development see Section 6.

Figure 5.3.2 Region A subtransmission network



Region A network design timeline shows how the network has evolved as we continue to meet our customers' expectations regarding service, reliability and resilience.

Region A network design timeline

Early 1900s

In 1903 Christchurch City Council established the region's first small-sale public supply of electricity – 200kW from steam produced by the city's recently installed rubbish destructor in the CBD. With the arrival of continuous power supply from Lake Coleridge in 1915 the Government's Addington substation supplied growing demand from a mix of underground cable and overhead lines. Additional 11kV grid connection points evolved at Bromley and Papanui and a comprehensive underground cable network then grew from these three main grid connection points.

1960s

This network served the city until the rapid development period of the 1960s when increased demand was met by building 66/11kV zone substations. These substations form the backbone of the present urban system. The initial design of our 66kV system was radial in nature. The exception to this approach was the double circuit 66kV line around the Port Hills which was built as a radial feed to Bromley. Later it became an interconnection between Bromley and Islington GXPs.

1990s

We saw continued load growth and New Zealand/worldwide system blackout events. We reviewed our network risks and introduced security standards. This resulted in changes to our network design philosophies which meant increased investment in interconnected 66kV subtransmission and zone substations.

2000

A new underground 66kV interconnection cable was laid from Bromley to the CBD to provide a second connection between Islington and Bromley GXPs.

2012

Orion continued to increase the interconnection of our 66kV network after the earthquake and the combined effect of four 66kV links and our cable and line route diversity provides a secure and resilient 66kV subtransmission network. This design proved itself during the 2017 Port Hills fire when Transpower lost supply to Bromley GXP. We were able to re-route supply using the newly completed 66kV link from Islington and therefore avoiding a potential significant loss of customer minutes.

2018

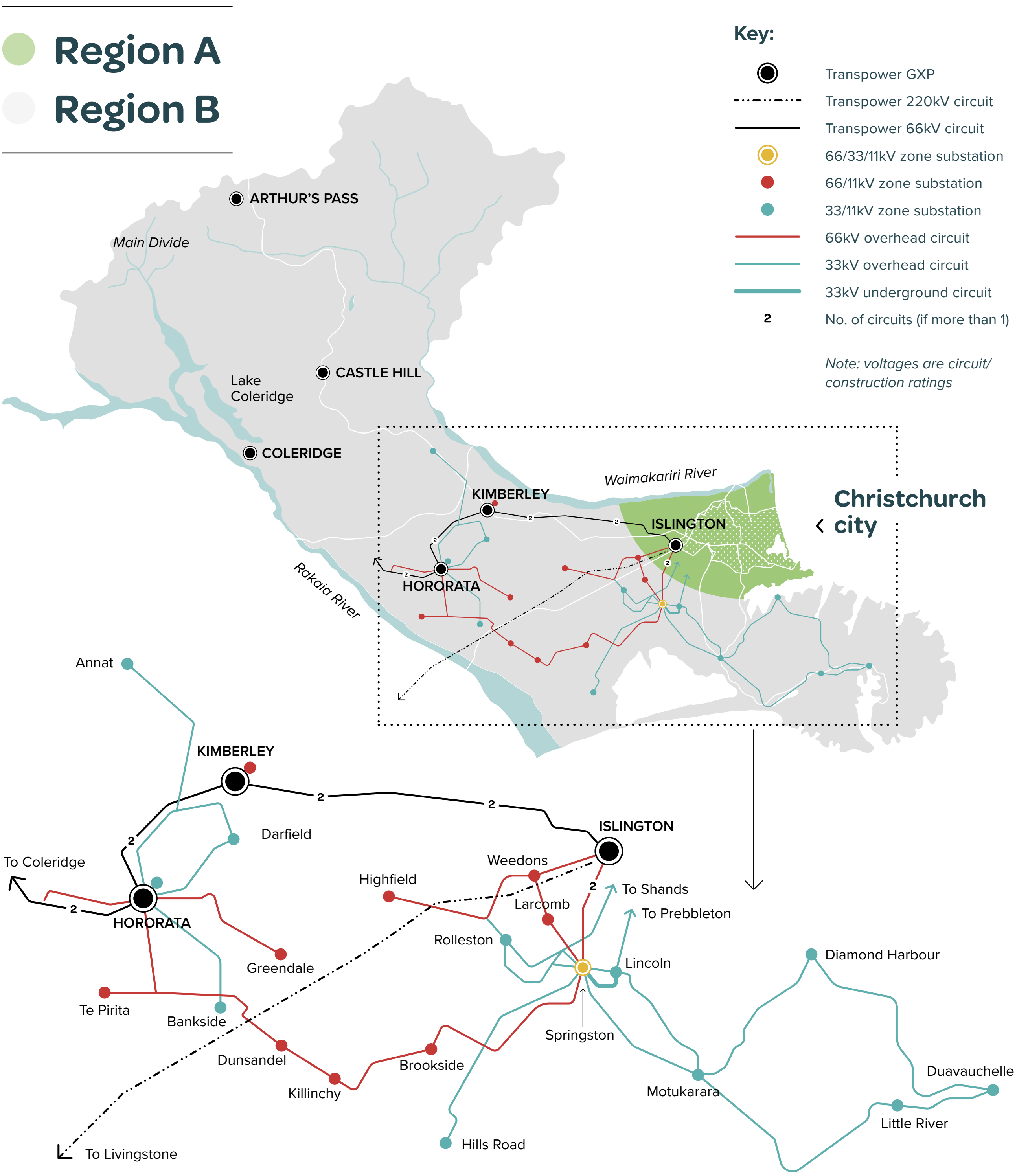
Progressively from 2012, Transpower transferred the Papanui, Bromley, Addington, Middleton and Islington 33kV GXP spur assets to Orion. These asset transfers were completed in 2018.

Present day

5.3.2 Region B subtransmission

Region B subtransmission network (Figure 5.3.3) consists of both a 66kV and a 33kV subtransmission system that supplies 22 zone substations from Transpower's Islington, Hororata and Kimberley GXPs. The distribution system primarily consists of 11kV overhead radial feeders from our zone substations and three small Transpower GXPs at Coleridge, Castle Hill and Arthur's Pass.

Figure 5.3.3 Region B subtransmission network



5.3 Network architecture continued

A timeline of how our Region B network has evolved to the current design is shown below.

Region B network design timeline

1900

1920s

The earliest rural electricity distribution networks were based on 3.3kV and 6.6kV systems supplied from connection points off the Coleridge transmission lines. These systems were simple radial lines, and were uprated to 11kV over time to service increasing demand.

1960s

Load growth required the introduction of 33kV. 33kV was always needed to get power to Duvauchelle in Banks Peninsula, because of the long distance from the old GXP at Motukarara. This 33kV subtransmission/11kV distribution system was eventually extended over most of the rural area and into western Christchurch.

1990s

The 'urban' part of this otherwise largely rural network evolved into a high load density area, with strong growth and higher reliability requirements. Overhead radial 11kV feeders have gradually been replaced with underground 11kV cables on this urban 33/11kV network.

2000s

Very high growth in irrigation loads has meant the 33kV subtransmission system has approached its design capacity. We decided the most economical reinforcement method was to build additional 66/11kV zone substations within the existing 11kV distribution network, while retaining (and converting to 66kV over time) the existing 33/11kV zone substations and 33kV lines.

2010s

As growth continues in the rural townships, and some larger customers are connected, Orion's network design now incorporates dual transformer substations around Lincoln and Rolleston.

2018

Progressively from 2012, Transpower transferred the Springston and Hororata 33kV GXP spur assets to Orion. These asset transfers were completed in 2018.

Present day

5.4 Major customers

Orion has approximately 350 customers with loads of at least 200kVA 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 to explore options to better manage their energy consumption, we work with them to meet their needs.

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.

Table 5.4.1 Major customers by load size

Load	Industry/Sector	Number	Notes
0.2 – 2MVA	Heavy manufacturing, hotels, water pumping, waste water, prison, retail and businesses	~330	
> 2MVA	Food processing	5	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. Fonterra plant commissioned during 2012 required a new zone substation (Kimberley).
	University	3	
	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.

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.

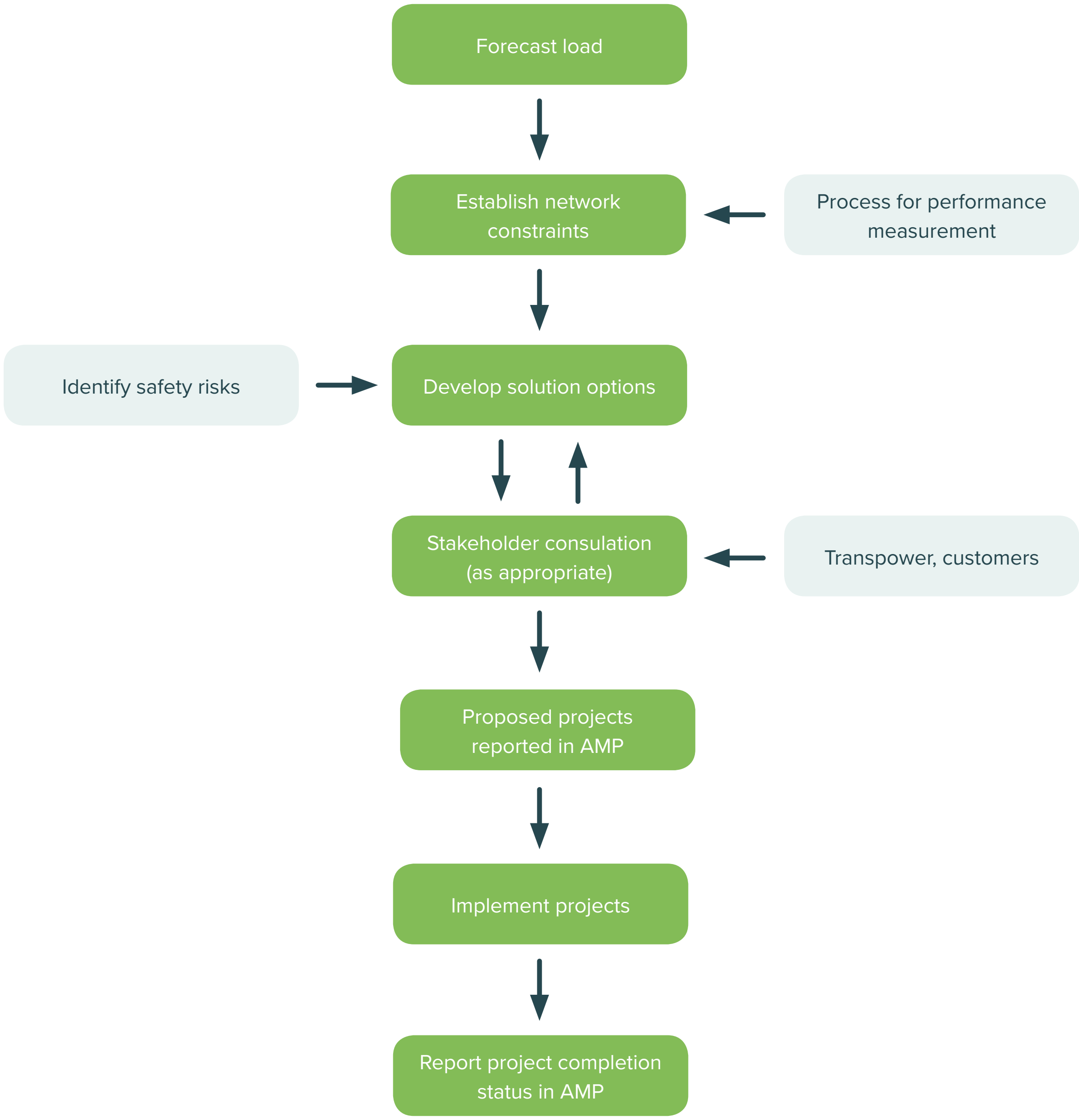
Recent changes in legislation, regulations and industry codes of practice have highlighted a greater need to mitigate safety risks for the public, employees and service providers. This means we have:

- continued to remove or modify high-risk equipment
- increased security around substations and equipment
- tightened controls on equipment access

Network security can be compromised during times of change when capital or maintenance works are carried out. To mitigate risk associated with reduced security during these periods of change we:

- plan work methods and contingencies to minimise any impact on the network
- use programmes that allow for contingency events
- programme works to provide consistent work for the skilled resources available
- are proactive in the development and retention of skilled people for the future

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 condition based 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.

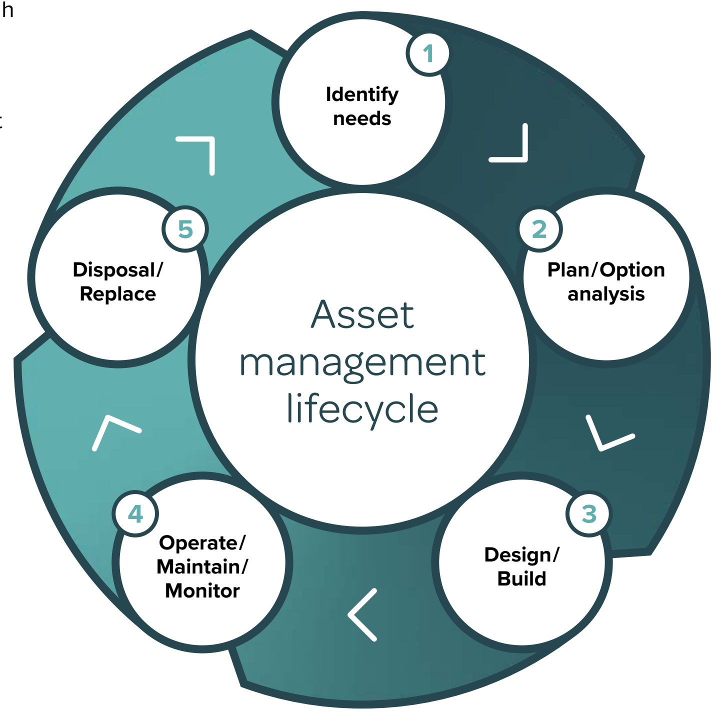


Figure 5.6.1 Asset lifecycle management approach

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.

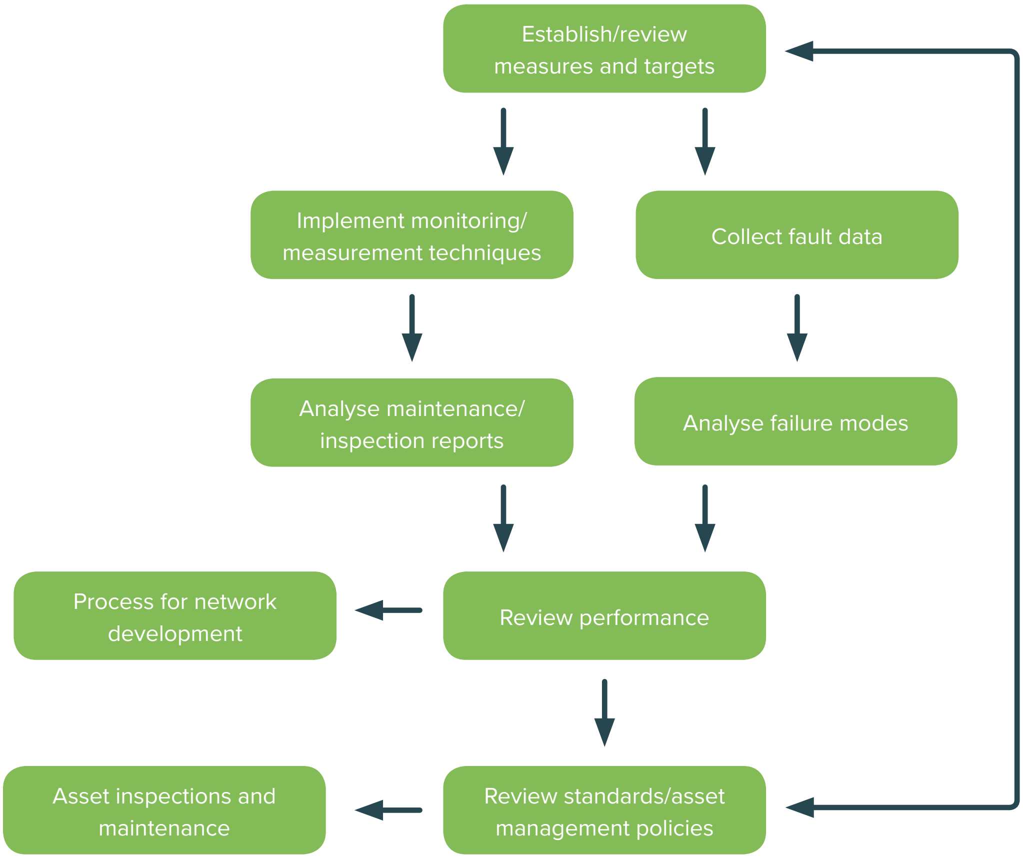
We are obligated to report and surrender a payment based on the unit of emission. For service level performance against targets, see Section 4.6.

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



5.6.2 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 maintenance plan and the replacement 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 FY20 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 (buildings & kiosks)						✓
Load management				✓		
Meters					✓	
Underground cables – Comms					✓	
Underground cables – 11kV			✓			
Underground cables – 66kV			✓			
Underground cables – 33kV			✓			

5.6 Asset lifecycle management approach continued

Condition Based Risk Management Model

In 2012 we engaged EA Technology Limited to develop 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 (HI) and Probability of Failure (PoF) of each individual asset. It then takes into account the consequence of failure to finally assign the risk to that particular asset. Our HI scoring is different to the Commerce Commission grading system set out in Schedule 12a of the information disclosure requirements. Figure 5.6.3 shows the method used to convert our CBRM scores to those required in Schedule 12a in Appendix F.

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

The model's process is summarised in Figure 5.6.4.
For further detail on the use of CBRM model to determine our replacement plan refer to Section 7.

Figure 5.6.4 CBRM process

1 Health Index

Inputs are asset age and factors such as its installed environment, operating duty, test results and performance. The factors vary for different asset classes. Based on input, it works out the ageing and deterioration of the asset. Classified as good, fair, poor and bad.

2 Probability of Failure (PoF)

PoF is calibrated using historical failure rate (and industry average, if available) of the asset class. The model allows for further refinements of the PoF as some assets can have significant degradation but relatively small probability of failing and vice versa for other assets.

3 Criticality

There are four risk categories. **As the consequences for the different categories are not the same, criticality weightings are applied.** Poles are used as an example for each of the risk categories:

Network performance	How many customers are affected by that pole? Higher the number of customers, higher the weighting.
Safety	How much asset is on the pole and where is the pole located? Transformer pole will have higher weighting than a normal pole. Special sites such as school will also have a higher weighting.
Financial performance	66kV pole will be more expensive to reconstruct than 11kV pole hence higher weighting for 66kV.
Environment	This is the impact on the environment should the pole fail.

4 Consequence of Failure (CoF)

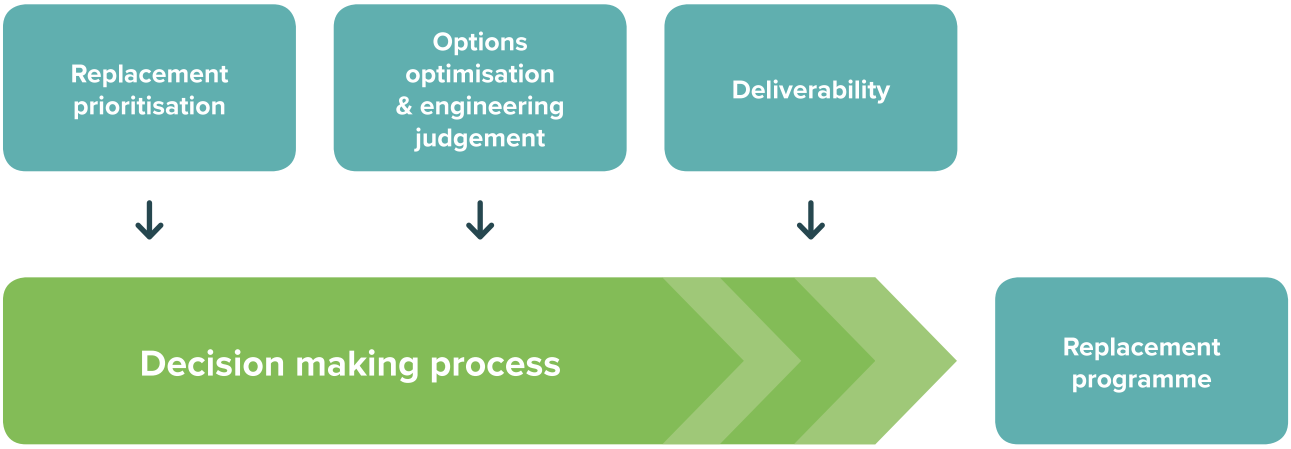
CoF is expressed in dollar terms. It is based on our own experience (and industry standard, if available). A risk dollar amount is given for each risk dimension defined in the model e.g., the risk dollar for fixing a 66kV pole is given for the financial performance.

5 Asset risk $

Risk is a function of the probability of failure, criticality and consequence of failure.

Using the tools to prioritise asset replacement is only the first stage of the replacement programme. The decision making process is described in Figure 5.6.5.

Figure 5.6.5 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.

The asset ranking refinement is done internally through discussions with infrastructure managers and asset engineers. They decide the order of replacement based on any external or internal influences.

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 or designed out
- type and technology of equipment, whether the existing type and technology is still the correct type
- manufacturer, standardisation of equipment, failure modes, industry experience with certain models, support from manufacturer
- safety
- synergy with any other changes of equipment in the substation, network or circuit
- 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. This number is used to determine how many units we can replace in a given period. 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

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.

Our network maintenance philosophy is reliability-centred and based on retaining a safe asset function. To do this we ask the following questions:

- what is the functional requirement of this asset?
- what is it that may fail and prevent this function?
- what can we do to retain the asset function?

Cost and benefit are considered and the results of maintenance activities are monitored to gauge the effectiveness of any significant changes. This works well for overhead line assets that have a higher failure rate, providing sufficient information to make informed decisions. However, when applying reliability-centred maintenance to assets with much lower failure rates, such as switchgear, information has to be obtained from a wide range of equipment before we decide on cost-effective actions.

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. This is managed through our contracting model. 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.

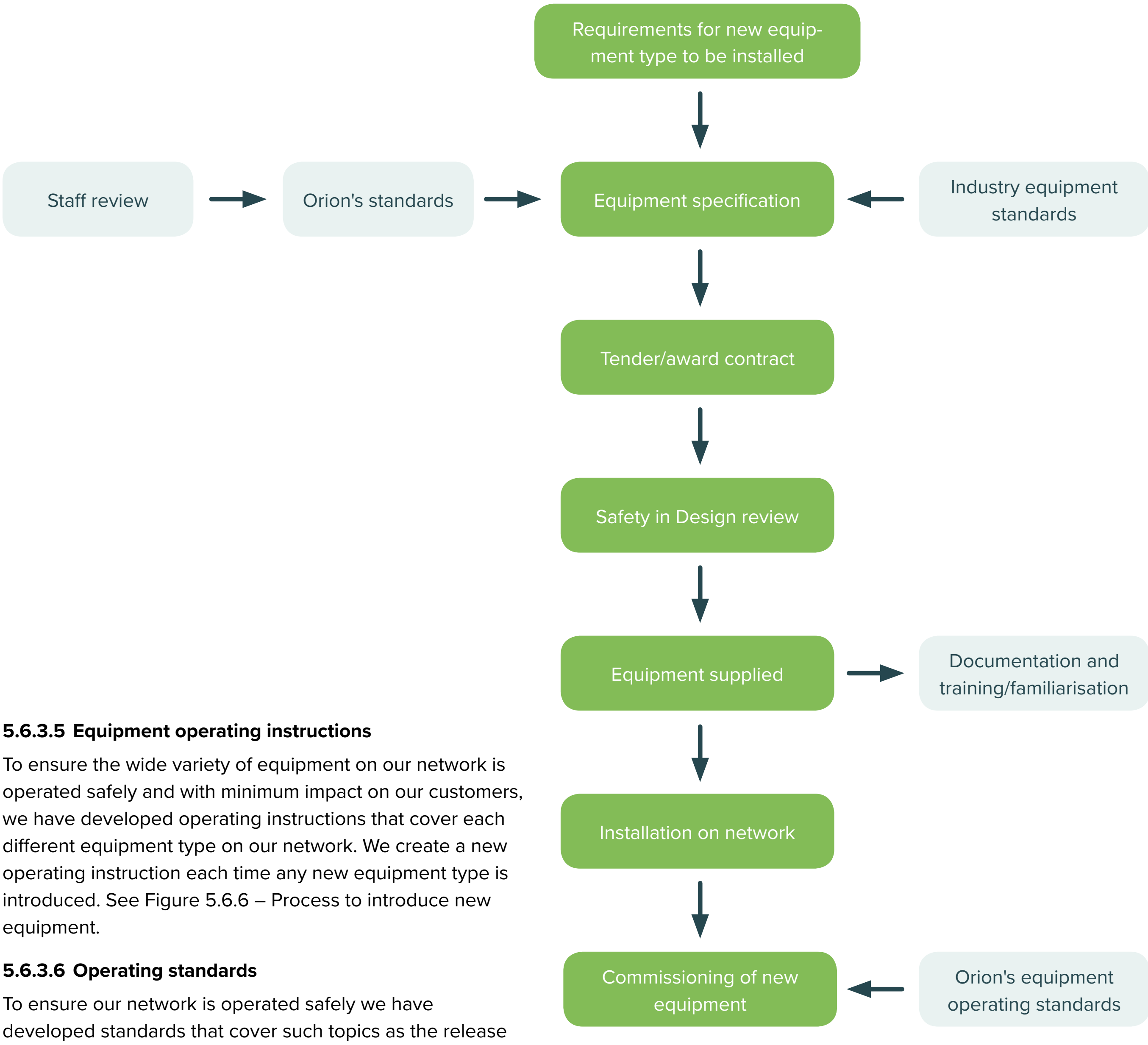
5.6.3.4 Equipment specifications

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.

Figure 5.6.6 Process to introduce new equipment



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

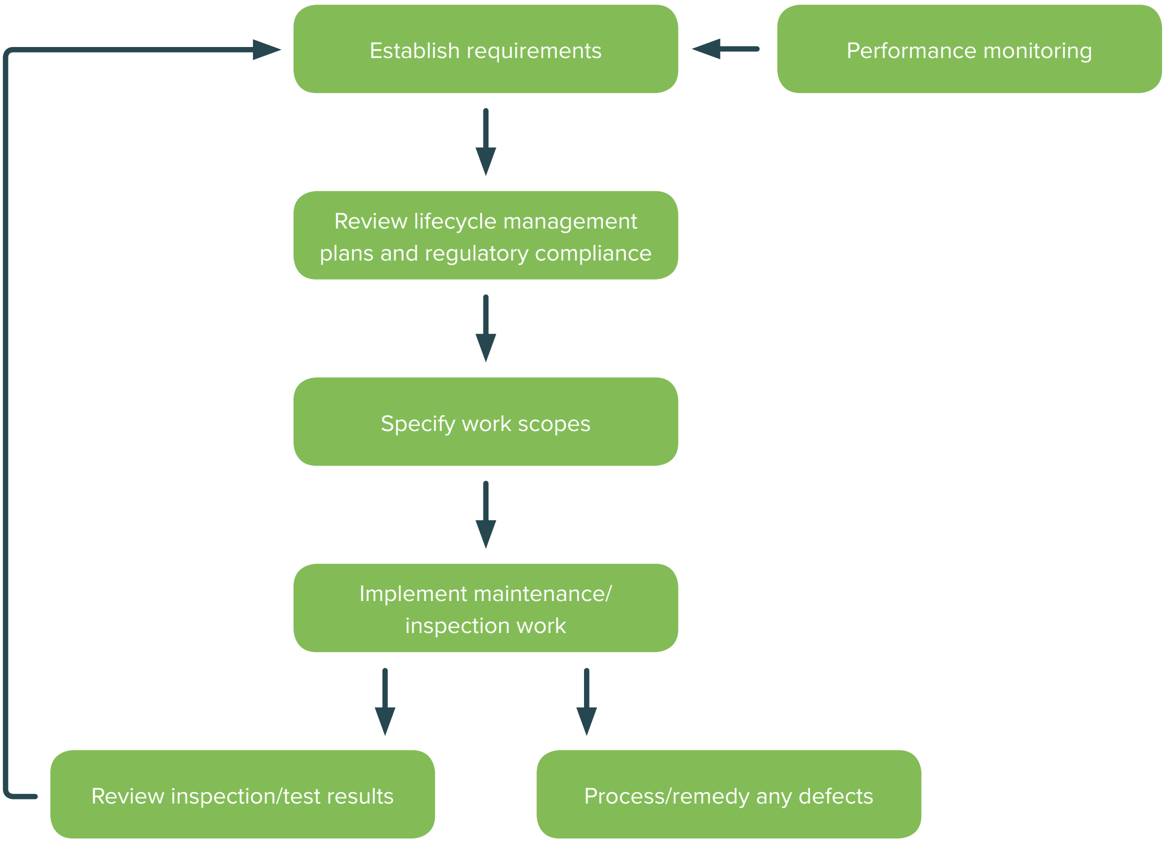
To ensure our documentation and drawings are maintained as accurately as possible, each is ’owned’ by one person who is responsible for any modifications to it. Our Asset Data Management team is responsible for processing these controlled documents using a process set out in our document control standard. 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.

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 5.6.7.

Figure 5.6.7 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 Business case approach

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 lifecycle management technical strategy covered in our Asset Management Reports.

Business cases are often underpinned by an overarching business case which addresses our security of supply architecture standards. Our infrastructure team, engineering managers, leadership team and other relevant support people provide internal peer review and challenge to these business cases and AMRs. We also share our thinking and a selection of business cases, meeting certain criteria, with our board for their comment and feedback.

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 implact, 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

This framework will be further refined and will incorporate assessment of future non-network projects.

6

Planning our network

Photo: We've been expanding Orion's network to service growth in new subdivisions, and have welcomed more than 5,000 new customers in the past two years.

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 our proposed projects our planning process has identified are needed to maintain the reliability, safety and sustainability of our network over the coming ten years.

Our capital expenditure keeps pace with the growing demand on our network which is forecast to continue. 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 western Christchurch. For example, at present the population of Rolleston sits at around 17,000 and is predicted to jump to more than 26,000 within a decade. Growth in industrial parks also continues as businesses take advantage of new energy efficient premises with easy to access to road and rail.

To support that growth we have planned significant projects:

- 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
- a new Region A zone substation at Belfast to supply load growth in northern Christchurch. Installation of 66kV cable links from Belfast zone substation to surrounding substations to provide N-1 security of supply and improve resilience

We are also investing in readying our network to enable our customers to take advantage in new technologies. It is an exciting period in our industry's history. New technologies, changing customer expectations and international decarbonisation efforts are resulting in the electricity sector facing more change than it has experienced over the last 50 years. 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 cleaner electric vehicles that are cheaper to run.

It is important our network is ready to help power the future needs of the community.

This energy transformation means identifying our customers' energy management behaviour is becoming more complicated as energy sources become distributed across and embedded in our distribution network. Maintaining the reliability and security of energy flow is becoming dynamic, as customers increasingly adopt new technology that puts more control in their hands.

Orion has an important role in helping our customers realise the advantages of their increasing energy options. Throughout our customer engagement forums and surveys, people have said they want us to be ready for them to take up new technologies and enable them to manage their energy consumption. It is important our network is ready to help power the future needs of the community.

The significant assumptions we take into account when planning our network can be found in Section 2.13.

6.2 Preparing for the future

6.2.1 The case for change

The prevailing electricity business model is largely uni-directional. Large generators sell their production in the wholesale market, and then the electricity is distributed to end user customers, via Transpower and lines companies such as Orion. Over the next few years this traditional one-way model may change for several reasons. These include:

- **Distributed Generation** – 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 unprecedented information access and management options at household and business levels
- **new consumption** – adoption of EVs and other new technologies will create new demand for energy. As batteries become more affordable and widespread they will both provide flexibility and resiliency options

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), or to flatten network demand curves
- 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 particular direction our customers and the market takes, we will invest in new systems and technologies to deliver future customer benefits over our AMP planning period.

6.2.2 Starting our journey

Our LV network supplies the vast majority of our residential customers so will carry much of the responsibility for adapting to meet the changes in our customers' energy use. Changes in technology and increased customer expectations mean greater visibility of what is happening on LV networks is now increasingly important.

Historically, LV networks were planned for reasonably stable household loads with one way power flow. In an environment where customers can now significantly change their electricity usage behaviour, LV networks become critical for future network management and facilitation of customer choice. LV networks must now be closely managed because of the significant additional demand household EV chargers can place on a street's LV system, or bear the two way flow of power potentially created by embedded battery systems or solar PV. In particular, voltage levels and maximum demand on LV circuits will need to be closely monitored, to ensure the capacity of the lines is sufficient.

Changes in technology and increased customer expectations mean greater visibility of what is happening on LV networks is now increasingly important.

To prepare for the future, our initial focus will be three, long term programmes to help us ready our LV network:

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

This programme will create greater visibility of our LV network 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

6.2.2.1 LV feeder monitoring

Commencing in FY20, we will begin a programme to install monitoring at around 35% of our distribution transformers over the next 10 years. We have selected those where an LV monitor would have maximum benefit. These are distribution transformers that have multiple customers and/or have interconnected LV networks. These have been chosen to enable us to develop our systems to be capable of providing active management at the LV level.

Our installation program will start relatively slowly, and ramp up from approximately 200 to 600 installations per annum during the 10 year AMP period. This rate of installation may vary depending on changing customer requirements and speed of adoption of new technologies, however based on information currently available to us we believe it is a prudent rate of installation.

Using modelling tools we have performed a high level analysis of more than 10,000 low voltage feeders. This has enabled us to identify areas which may have reduced ability to absorb the effects of new technology. Based on this information our monitoring installation program will prioritise certain feeders for installation first. The feeders most likely to be constrained first will typically be older overhead feeders because these feeders may have less available capacity on them than those in newer residential areas as a result of residential infill over the past 50 years.

6.2.2.2 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, further information is required. 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 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 boundary box, or
- existing smart meters installed on the meter board at the customer's home

Our preference is to use smart meters already installed on homes as this is likely to be the most cost effective option, and has the potential to provide other valuable information, compared to Orion installing new standalone monitors.

We are working with industry parties who own smart meters 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.

6.2.2.3 LV network reinforcement

Based on modelling undertaken to date, we believe our low voltage network is in good condition. However, as new technologies are adopted by more households and businesses, and as we receive more data on our low voltage network, it is expected reinforcement above historic levels will be required.

We will undertake network reinforcement through a portfolio of measures such as adding new transformers, installing new lines and cables, undertaking greater customer demand management or using non-traditional newly available technology such as static synchronous compensators (STATCOMs) or network batteries to provide reactive voltage support.

We have trialled STATCOMs and consider them acceptable for voltage regulation. This innovation delivers on our asset management strategy focus on providing a safe, reliable, resilient system, ensuring health and safety and embracing the opportunities of future networks.

STATCOMs and batteries, may be able to manage power factor, harmonics and voltages to provide a fast and flexible alternative to building new traditional networks. By providing a 'tactical buffer', customers will have the freedom to deploy low carbon technologies without waiting for potentially time-consuming network reinforcement to take place.

Commencing in FY20, we will begin a programme to install monitoring at around 35% of our distribution transformers over the next 10 years.

We are working with industry parties who own smart meters to obtain access to smart meter information and are hopeful this is achievable.

6.2.2.4 Improved forecasting and modelling

Our improved forecasting and modelling techniques will need to interact with other systems, such as our GIS platform. They will also cover a range of performance factors, including transformer utilisation, voltage imbalance and power factor.

Different types of forecasting/modelling techniques are required:

- short term forecasts 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 can avoid outages as well as prolong the life of assets, translating into reduced customer interruptions
- medium term forecasts are helpful in assessing investment choices for a subsequent financial year
- long term forecast scenarios enable assessment of the potential impacts from scaled up adoption of low carbon technologies by customers, including clustering impacts
- electrical safety concerns both on our network and in-homes may be identified from smart meter information
- modelling outputs in particular power flow projections which identify voltage fluctuations, violation limits, fault currents etc., as a tool in the operation of our network.

To enable the intersection of monitoring, modelling and network management, we will implement secure and reliable software systems and communication solutions to capture the necessary data, apply the modelling tools, and issue operational instructions to the various technology devices deployed on the network. Such control instructions may be either direct to devices, or signalled to another party such as a retailer or aggregator, who then signal the devices. Such devices are likely to include batteries and electric vehicles in homes and businesses.

6.2.2.5 Integration with operational systems and business processes

All of our technical solutions will be fully integrated into the distribution network control centre. We plan for our current PowerOn management system will be able to be incrementally upgraded to support these solutions, avoiding the need to purchase and implement an entirely new management system, see Section 7.16.

The incremental improvements to the way we operate our network will require a lot of systems integration and business process changes, as well as possible changes to industry agreements. However, we view the improvements as being evolutionary rather than revolutionary, and build on our existing load management and upper South Island coordination expertise.
It is also our desire to develop our systems within a strategic framework of allowing non-discriminatory secure data access and transfer to eligible market parties and customers.

All of our technical solutions will be fully integrated into the distribution network control centre.

To help ensure this occurs in a low cost and efficient manner we will continue collaboration with retailers and other industry players, on technology development, process and communications platforms. Current examples of this are:

- our engagement with Gathering Renewable Energy in Electricity Networks project (GREEN Grid) on a number of future network issues. This research project is to ensure New Zealanders have access to reliable, safe and affordable renewable energy
- partnering in a trial with a major electricity retailer on a smart technology and communication solution for household customers
- trialling low voltage monitoring systems on our transformers with metering providers.

Such collaboration is a very low cost means of ensuring we develop systems and approaches that suit the broader market and our customers.

6.3 Preparing for growth

6.3.1 Overview

Network development is driven by growth in peak demand, not energy. 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 incorporated the impact of the Canterbury earthquakes, including returning loads to their normal supply points. However, there is more uncertainty than usual around workforce numbers associated with the regeneration of Christchurch and the range of scenarios from uptake of electric vehicles and other emerging technology.

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.

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.

6.3.2 Maximum demand

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.

This pattern is 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.

Many things influence changes in behaviour that affect how customers consume energy. These include advances in technology and available energy options. Other behaviour factors we need to consider include milk processing plant upgrades and customer demand management initiatives. Our network peak occurs in winter.

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 FY19 was 580MW (the peak that occurred on 6 June 2018), down 25MW 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.

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, industrial decarbonisation and what size charger will be used are all current unknowns.

6.3 Preparing for growth continued

- **Customer actions** – how customers will respond to signals of high cost power or high CO_2 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 installations, of solar 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 will they 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 of our maximum demand scenario planning assumes that 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, other new customer connections and ongoing regeneration in the Central City. Winter peak demand on our network is anticipated to increase by approximately 100MW (16%) 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 each year in as load growth is observed.

Our maximum demand is linked with cold weather. As FY19 was relatively mild the maximum demand that year was relatively moderate. The forecast maximum demand for FY20 and beyond reflects an increase in demand from Christchurch CBD commercial development, Christchurch's the new central library, Tūranga, and a larger Christchurch Hospital campus.

Figure 6.3.1 Overall maximum demand trends on the Orion network

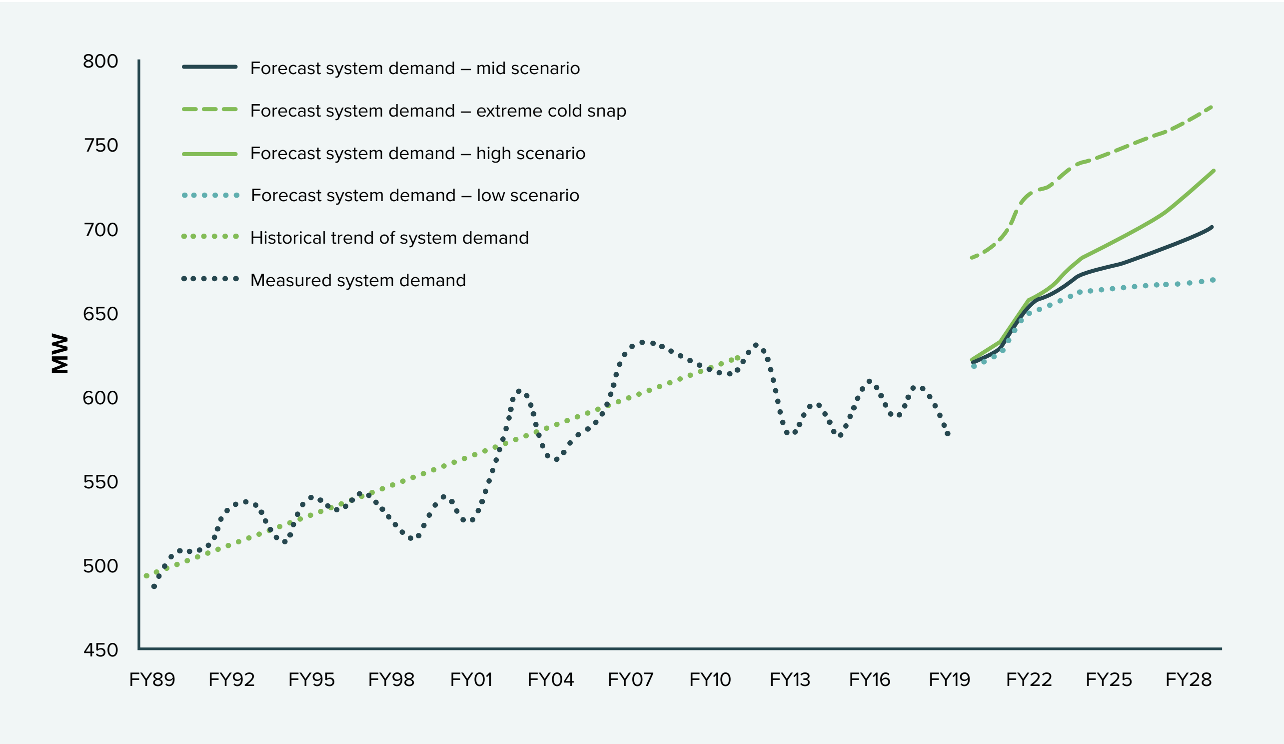


Figure 6.3.1 shows four forecast scenario:

- **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. The above average increase in the short term is driven by a strong residential growth forecast and large commercial connections, for example Belfast Industrial, and Central City projects coming on stream including the Christchurch Town Hall and Convention Centre.

  For EVs we have used Ministry of Transport potential uptake figures as a baseline. This assumes 11% of the region's vehicle fleet will be electric in 10 years and we have assumed 20% charging at peak times. Towards the end of the 10 year period, growth from electric vehicles becomes a significant part of our forecast growth. 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 and a doubling of the electric vehicle impact – either double the number of EVs or double the number charging at peak.

Clustering of new technologies may occur at a street or neighbourhood level, before overall numbers on our network are substantial.

This clustering effect is one of the reasons why we need to understand our low voltage network better – we need to know which streets are having EVs, solar and batteries introduced to them.

- **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.

  As can be seen in Figure 6.3.1, the influence of new technologies such as EVs has a significant bearing on our network-wide maximum demand.

  With the changing energy landscape, maximum demand will also need to be closely monitored at the low voltage level to ensure the capacity of LV lines in particular 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. Clustering has been witnessed in the UK where 70% of solar penetration at household level occurs on just 30% of UK streets.

  This clustering effect is one of the reasons why we need to understand our low voltage network better – we need to know which streets are having EVs, solar and batteries introduced to them.

6.3.2.1 Demand forecasting uncertainties

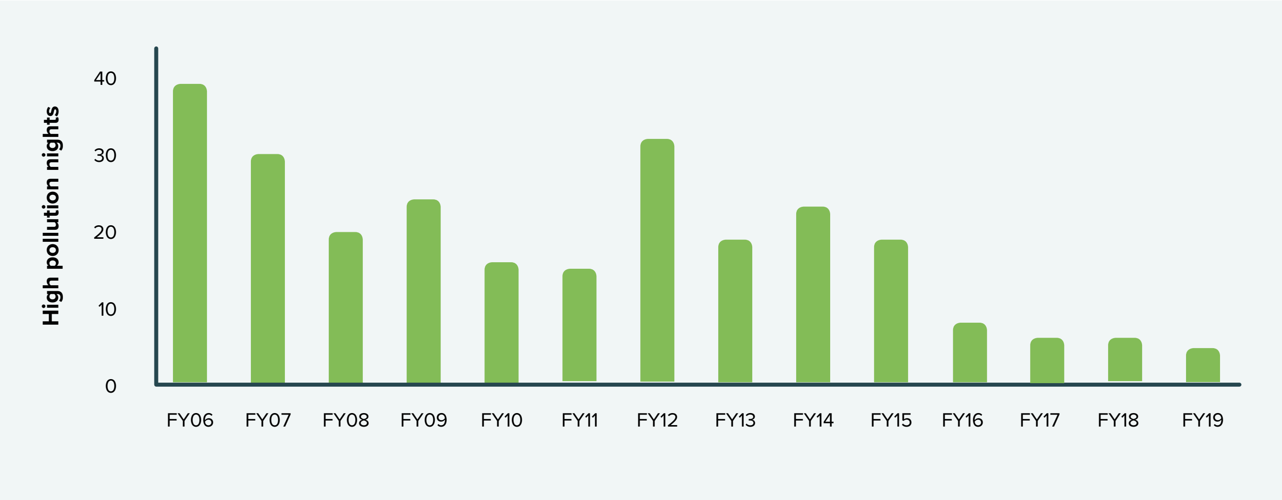
This section provides further detail on some of our assumptions with regard to the more significant uncertainties we face in our demand forecasting.

Clean Air Plan

ECan introduced new rules from February 2016 under the Proposed Canterbury Air Regional Plan. These rules phase out low emission enclosed burners in Christchurch. As the analysis of the clean heat programme showed minimal increase in electricity demand, these new rules are not expected to have a material impact on power loads. As at 12 September 2018 there were four high pollution days for 2018. This is a noticeable improvement over recent years but still short of the 2016 National Environmental PM10 target of having no more than three high pollution days. This reduces to no more than one day per year from 1 September 2020.

Orion has experienced rapid growth in summer irrigation load on the Canterbury Plains.

Figure 6.3.2 Christchurch high pollution nights



Irrigation

Orion has experienced rapid growth in summer irrigation load on the Canterbury Plains. In order to meet this growing load, substantial investment has been needed in our subtransmission and distribution networks.
We closely monitor trends in rural irrigation. Some factors now influencing planning for irrigation load are:

- ECan constraints on groundwater extraction
- land in some areas is approaching its full irrigation potential
- interruptible load arrangements to cover short term fault situations
- design and implementation of the Central Plains Water irrigation scheme
- Trustpower's potential to install up to 70MW of hydro generation from Coleridge along the north bank of the Rakaia River to its gorge
- The CPW irrigation scheme has changed irrigation in the affected area from ground water extraction to pumping from a canal into a piped network delivering on-farm pressure

Over the next 10 years, milk processing plants are anticipated to be responsible for approximately 29MW of summer peak growth. The timing/demand changes due to the milk processing plant upgrades causes significant uncertainty in this forecast. For this reason we are cautious about our development plans to ensure that we do not install assets that may later become under utilised.

Water bottling

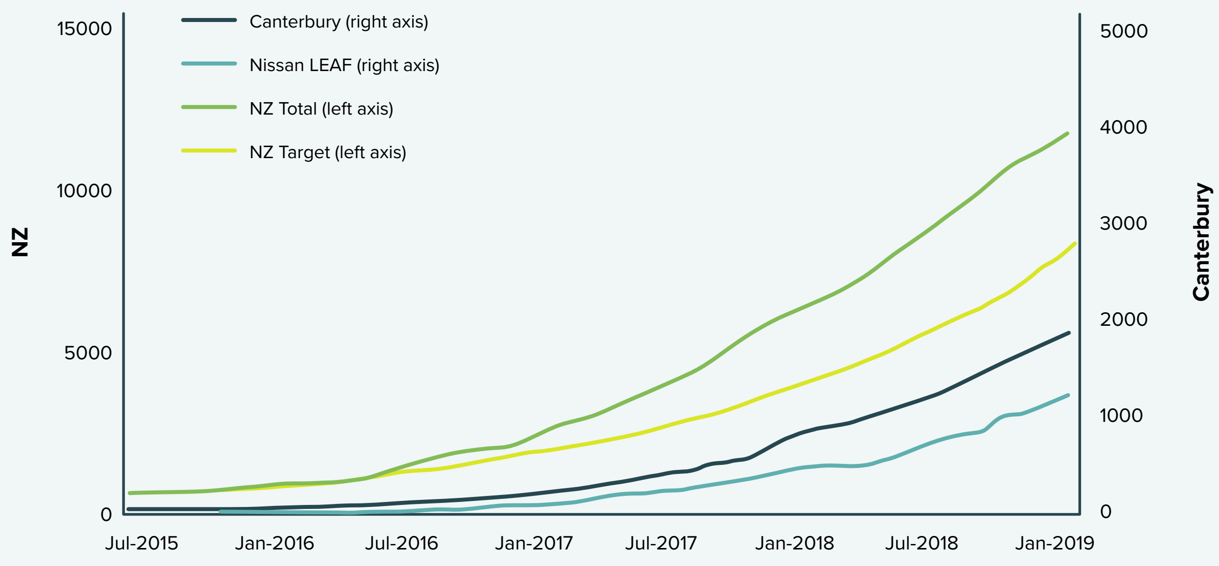
Plans for the development of further water bottling sites in Belfast area are under discussion. These could add at least 16MW of load in this area. The continuous operation of these plants will benefit our overall load factor.

Electric vehicles

Electric vehicle uptake is increasing above forecasts, driven by used Nissan LEAF imports. The uptake rate now supercedes the PV uptake rate. 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 uptake has more than doubled each year as shown in the Figure 6.3.3.

Clustering of EV uptake due to neighbourhood demographics may impact areas of the low voltage network before overall numbers are substantial.

Figure 6.3.3 Electric vehicle uptake



We have undertaken some preliminary desktop analysis to determine the impact of electric vehicles on the low voltage network. High penetration levels of EVs would erode security of supply margins.

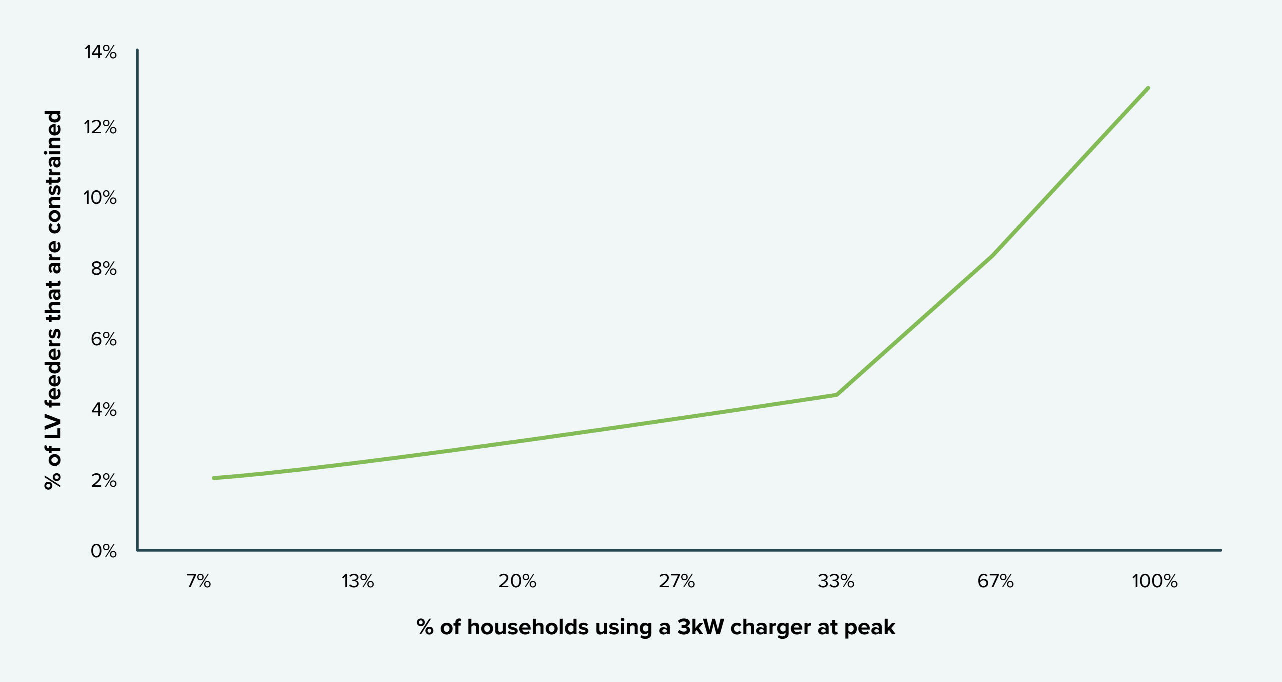
Figure 6.3.4 summarises our findings, based on an assumption of EV owners charging their cars on average between 3kW and 4kW.

It is worth noting the slope of the curve toward higher penetration levels, even with relatively small 3kW chargers assumed, and therefore the importance of the accuracy of the modelling inputs. Whilst most of our low voltage network appears able to provide for quite high electric vehicle penetration levels under normal network conditions, as EV penetration increases it is important that we do not rely on desktop based studies alone to determine the condition of our network. This is one of the reasons why we are seeking to monitor our low voltage network (see Section 6.2).

As more information is gathered, our understanding of the community's adoption of EVs and their charging habits will improve.

As more information is gathered, our understanding of the community's adoption of EVs and their charging habits will improve.

Figure 6.3.4 Residential area LV constraints

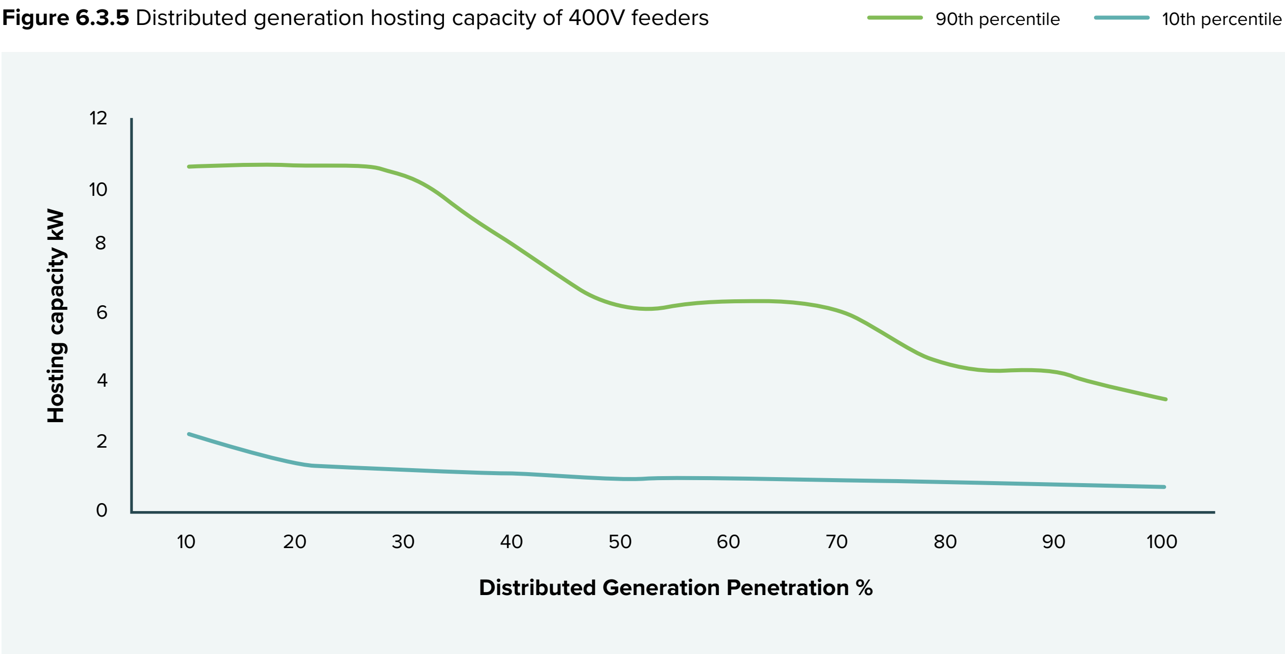


Distributed Generation

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 6.3.5, courtesy of University of Canterbury, provides a preliminary summary of our network's ability to host DG without the need for reinforcement. The large range of hosting capability – the graph shows diverse range from 10th percentile to 90th percentile – reflects the low voltage feeder characteristics and customer types connected to them. For example, we have long rural, short urban, overhead, underground, residential, commercial and industrial etc. This demonstrates the need to have DG hosting capacity specified on a per low voltage feeder basis rather than a 'one size fits all' basis that would require us to act conservatively.

Figure 6.3.5 Distributed generation hosting capacity of 400V feeders



6.3 Preparing for growth continued

Figure 6.3.6 shows the mix of DG on our network. Although solar PV is the dominant form of DG by connection count, its peaking capacity is significantly smaller than the peaking capacity provided by peaking diesel generation. The annual energy delivered from solar is similar to that from diesel generation.

Figure 6.3.7 shows solar uptake in terms of connections and capacity since December 2007. 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 6.3.8 shows that the uptake rate peaked late 2016 and is now dropping.

Figure 6.3.6 DG connections on Orion's network

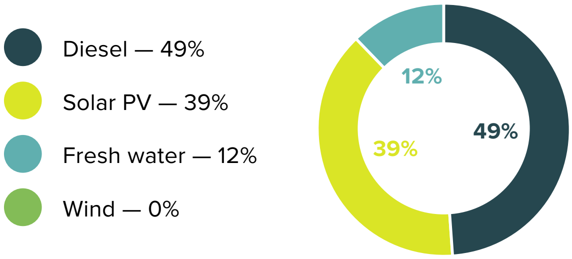


Figure 6.3.7 Current level of solar PV uptake on our network

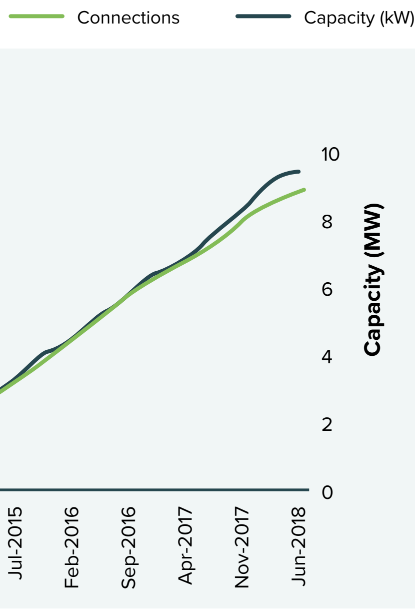
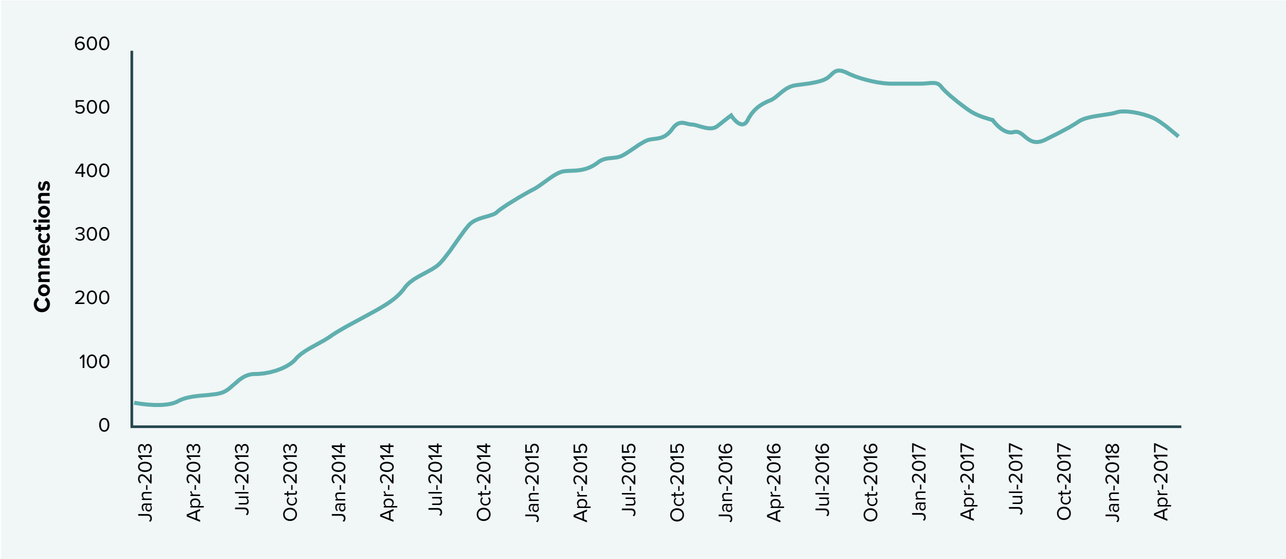


Figure 6.3.8 Rolling 12 month increase in solar PV connections



6.3.3 Territorial authority growth

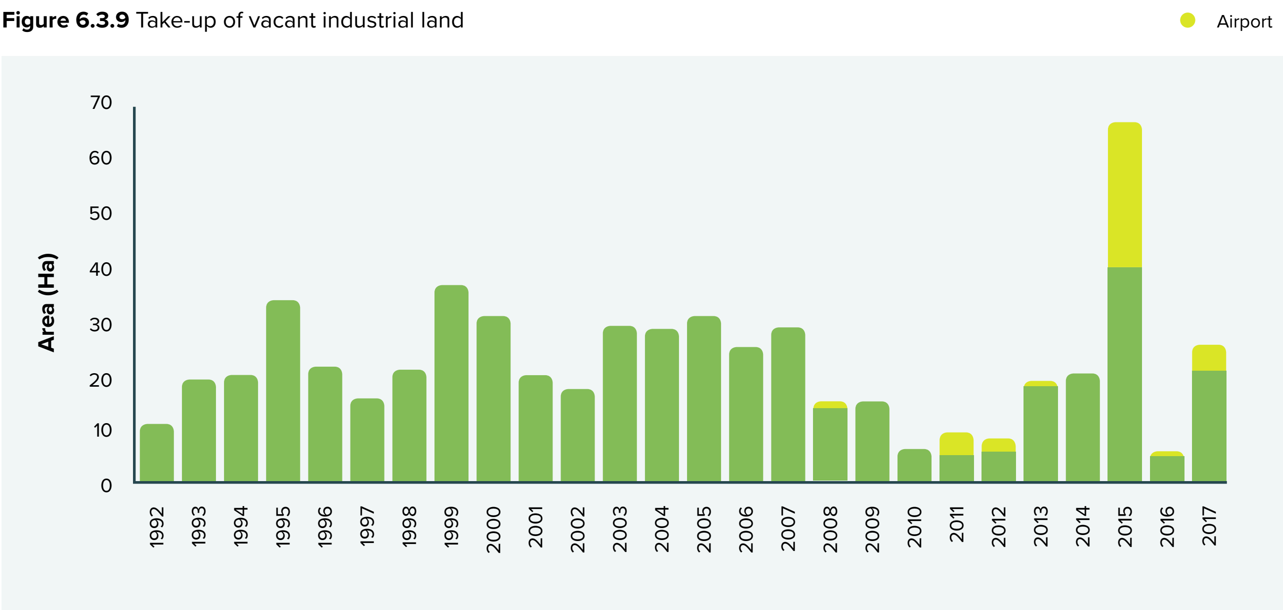
Our network spans two territorial authority areas; Christchurch City Council (CCC) and Selwyn District Council (SDC). The following information summarises our forecasts for each of these territorial areas, before we move into demand forecasts at GXP and zone substation level. Both territorial authorities 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 growth forecast (Region A)

CCC (Region A) forecasts yearly household growth by census area unit to 2053. To forecast the growth in residential demand in the CCC area, we map each of the area units to one or more zone substations in our model.

To forecast industrial growth we utilise the CCC 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. Figure 6.3.9 shows how the uptake has been affected by the 2009 economic slow down and 2011 earthquakes. The record low in 2016 is thought to partly relate to uptake in the Rolleston Izone business park in Selwyn District.

Figure 6.3.9 Take-up of vacant industrial land



Finally, we utilise the 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 swings of the commercial development market.

In summary, in the medium term CCC's District Plan review expects to deliver an increase in residential infill within the Central City and areas around the shopping malls by introducing Medium Density Residential zones and Suburban Density Transition. In the short term, major subdivision growth is planned for Halswell, and Belfast. Industrial development is expected to mainly continue in Hornby, Islington, Wigram, Belfast and the Airport areas.

6.3.3.2 Selwyn district growth forecast (Region B)

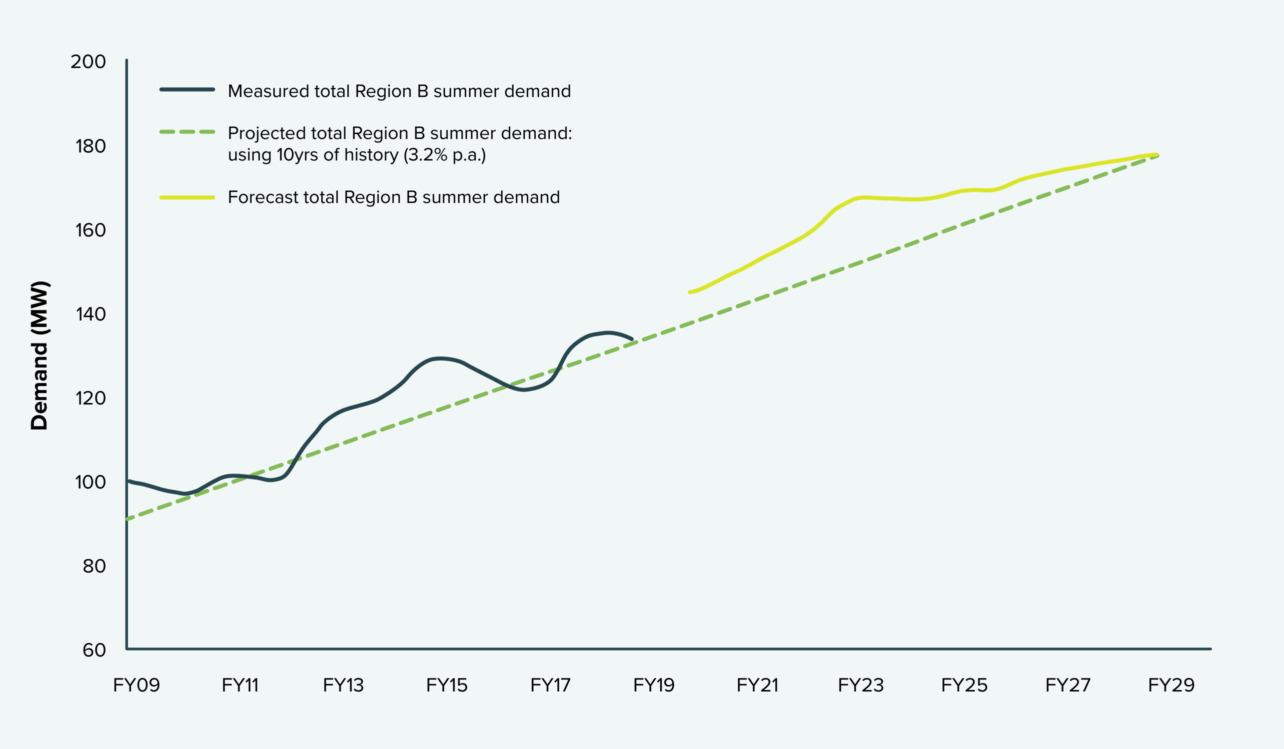
As with the CCC, we utilise the latest Selwyn household growth projections to forecast residential growth in the greater Selwyn region. Most of our zone substations within Selwyn District are required to meet irrigation load and predominately have their peak load in summer. However significant residential growth has occurred around Rolleston 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 44MW (33%) in the next 10 years.

The Izone industrial park at Rolleston has also experienced significant growth in recent times and we are working closely with the developer to ensure that our forecasts in this area are consistent with their expectations.

In the short term, major subdivision growth is planned for Halswell, and Belfast. Industrial development is expected to mainly continue in Hornby, Islington, Wigram, Belfast and the Airport areas.

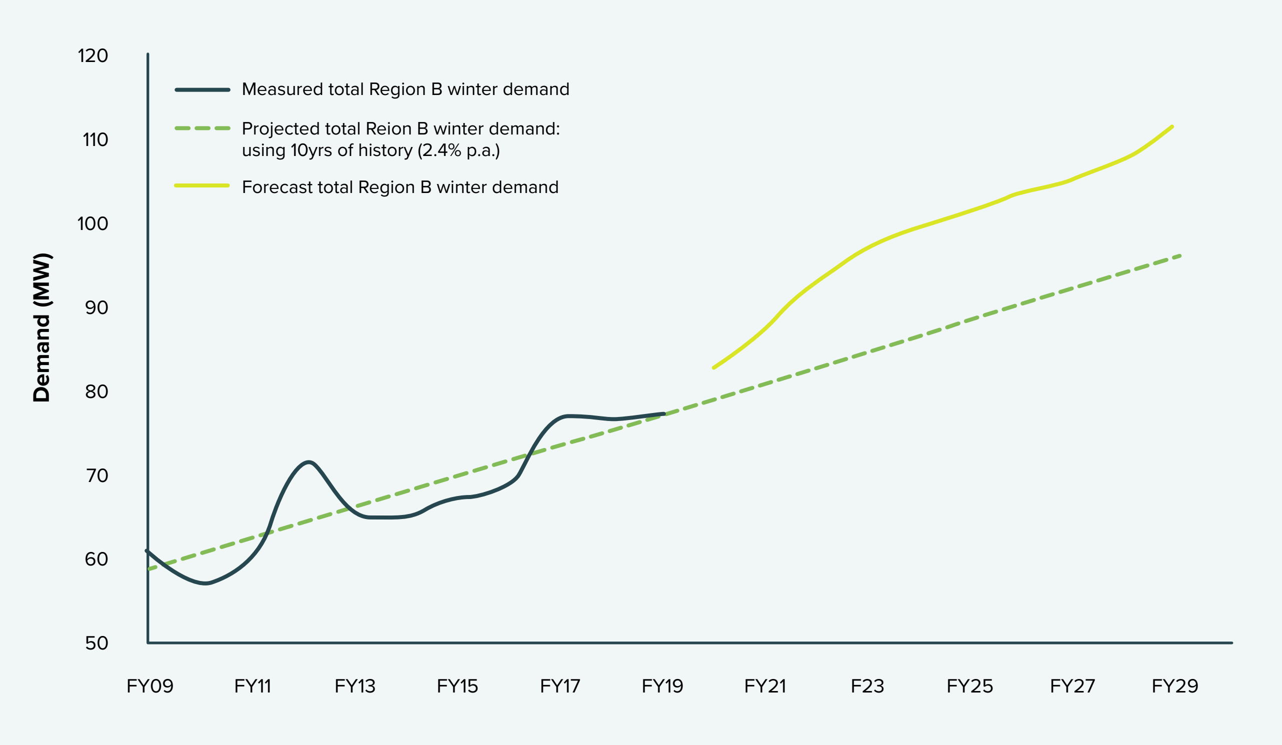
The increased focus on decarbonisation of industry also contributes to the electrical growth in this region. Figure 6.3.10 shows recent summer load growth in our Region B area. FY13, FY15 and FY18 were good examples of a dry summer. FY14 irrigation demand was subdued due to rain events during the summer months. This was offset by Fonterra adding a second drier to their plant near Darfield.

Figure 6.3.10 Region B summer maximum demand (MW)



Region B winter load growth is shown in Figure 6.3.11 The FY12 peak is due to a significant August snowstorm. Selwyn District Council's 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 and milk processing plants developing winter load.

Figure 6.3.11 Region B winter maximum demand (MW)



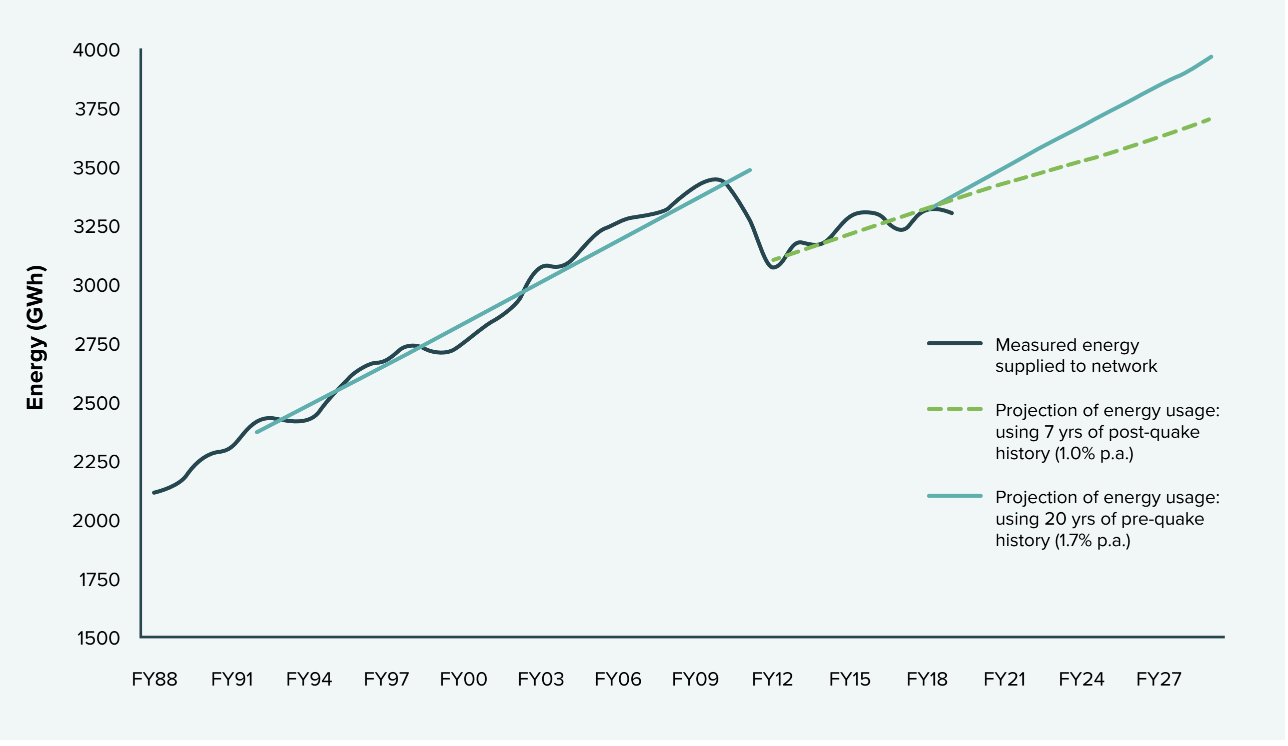
Selwyn District Council's residential forecast indicates significant growth is expected to continue around Rolleston and Lincoln townships for a few years.

6.3.4 Overall load growth

6.3.4.1 Energy throughput (GWh)

Our region's 20-year history in Figure 6.3.12 shows an average growth rate of about 1.7% each year. The drivers behind this growth were growth in population in Christchurch, growth in holiday population for Banks Peninsula and changes in land on the Canterbury Plains. For the seven years post the Canterbury earthquakes, energy growth has been 1.0% each year.

Figure 6.3.12 Orion network annual energy growth rates



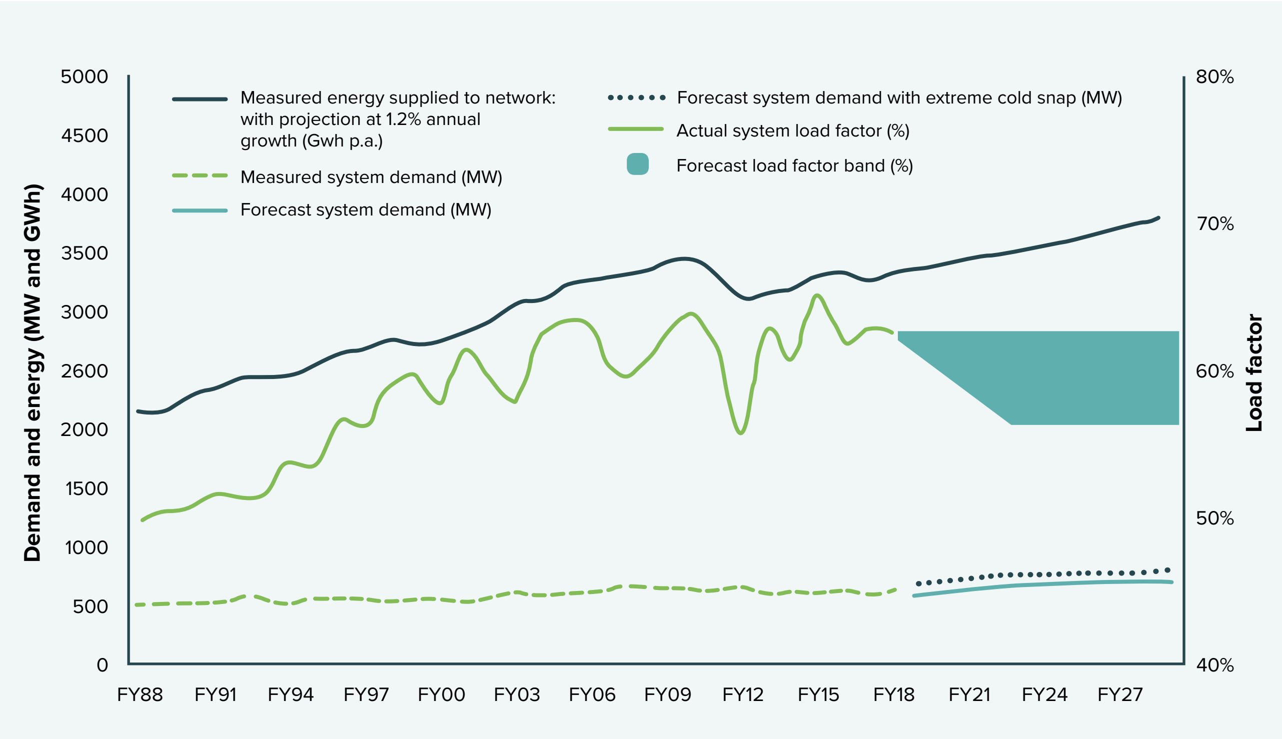
6.3.4.2. Load factor

Overall network utilisation is indicated by the system annual load factor as shown in Figure 6.3.13, defined as the ratio of average to peak demand. The peak used in this calculation is based on the maximum demand which as noted in the previous section excludes temporary excursions that are not used for forecasting demand.

Orion's annual system load factor had generally improved until 2005, then plateaued, although with significant variations such as vagaries in our weather influenced maximum demands. Improvements in load factor had come from increased off-peak loads from irrigation, milk processing plants and summer air conditioning, combined with effective control of winter peak loads through price signalling and encouraging alternative fuel use for on-peak heating. Winters with extreme cold weather such as snow in June 2006 and August 2011 often lead to lower load factors due to the very high peak load.

This type of weather would give load factors near the bottom of the forecast band. Off peak EV charging will increase load factor but this is offset by increasing solar PV generation.

Figure 6.3.13 System load factor



6.3.4.3 Load Duration

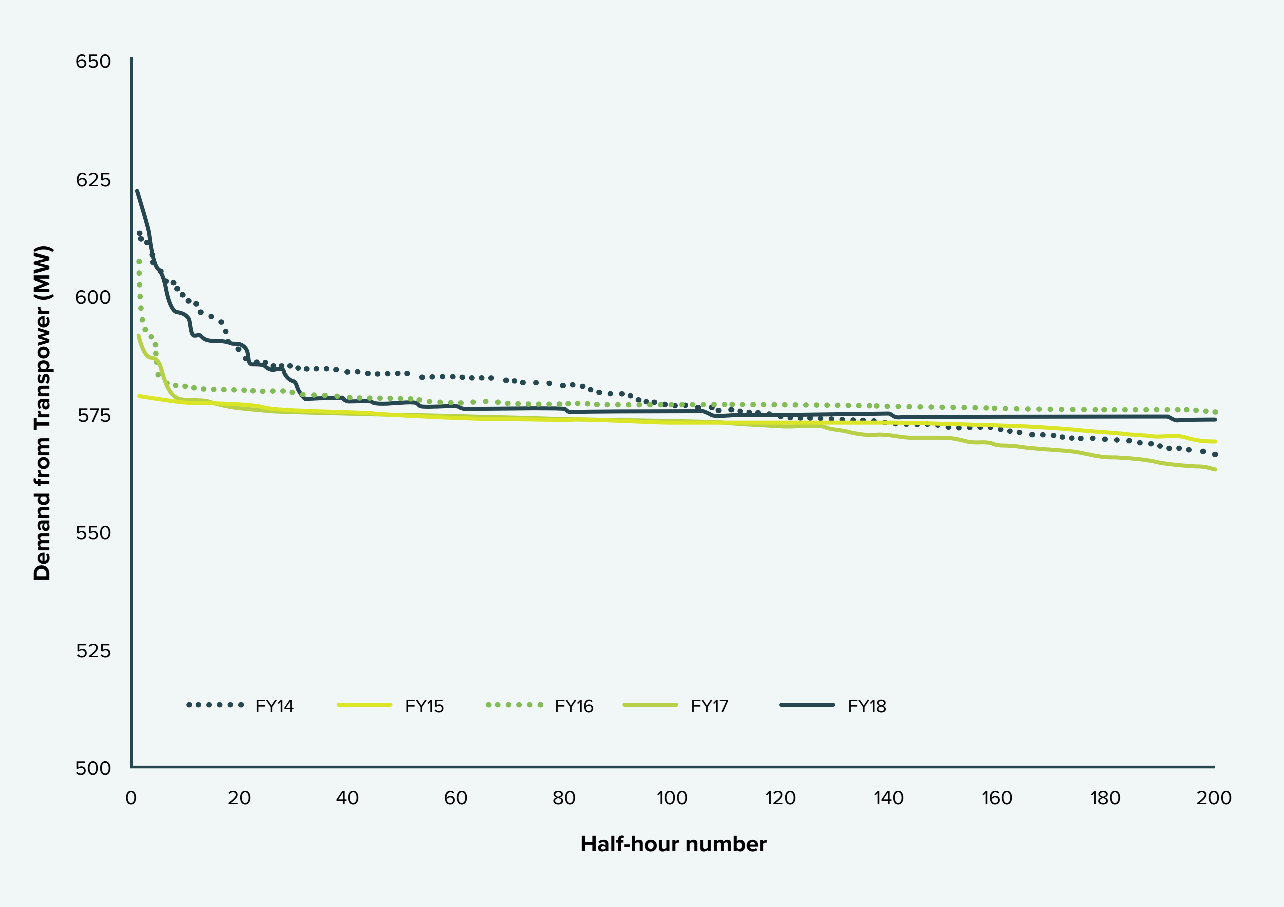
With constantly changing load on our network, the peak demands that determine network capacity generally only occur for very short periods in the year. Figure 6.3.14 shows the load duration curves of our 200 peak half hour demands on Transpower's network over 5 years. The graph shows that Customer Demand Management has been successful in flattening the curve in recent years.

The Transpower grid requires sufficient capacity to meet load during extreme weather conditions that may last for only a few hours. Peaking generation can help delay the need for increases in Transpower's network capacity.

Generation may also be used to reduce Transpower's charges. If used for this purpose, longer hours of operation might be needed, especially to avoid reductions in water heating service levels.

Control of the dominant winter maximum demands depends heavily on suitable price signals, and customers' response to them. If this is to continue to be effective then it is important that electricity retailers continue to support Customer Demand Management initiatives. Of particular importance is the promotion of night-rate tariffs and load control. This is via the on-going installation and maintenance of ripple control receivers, and new technologies delivering this function.

Figure 6.3.14 Christchurch area network – load duration curves



6.3.4.4 Network connections and extensions

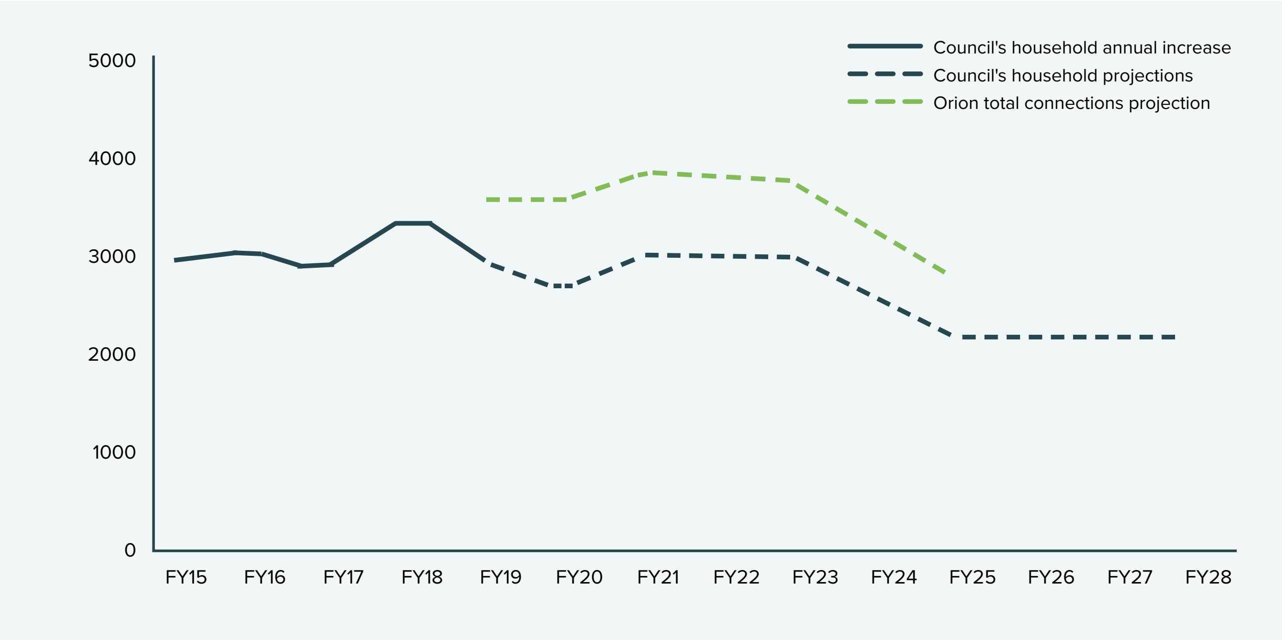
Network connections can range from a 60 amp single-phase connection to a large industrial connection or a big subdivision of several thousand kVA.

Subdivisions

The level of subdivision activity depends on economic conditions and population growth. The Land Use Recovery Plan March 2015 Monitoring Report indicated residential intensification has been less than expected, which has increased household numbers in outlying areas. Selwyn District Council has increased its projections for residential growth by 500 per year for the next few years. The 2018 forecast update has the annual increase in households remaining ~3,000 for several years then dropping to 2,000 as shown in Figure 6.3.15 below.

Selwyn District Council has increased its projections for residential growth by 500 per year for the next few years.

Figure 6.3.15 Councils' projection of increase in household numbers



In our rural area most subdivisions are for lifestyle reasons. In our urban area it can be industrial, commercial or residential, though most developments are residential. Our subdivision investment is made after negotiating with the developer on the basis of a commercial rate of return.

The green lines in Figure 6.3.15 represents the total projected number of newly established connections at Orion. This includes residential, streetlighting, residential, irrigation and major customers. Approximately 85% of our total connections are residential and this is shown as the council's household projection in Figure 6.3.15. Going forward, we project the total number of connections to drop from 4000 down to 3000 per annum in FY25. This projection is also tabulated in Schedule 12c in Appendix F.

6.3 Preparing for growth continued

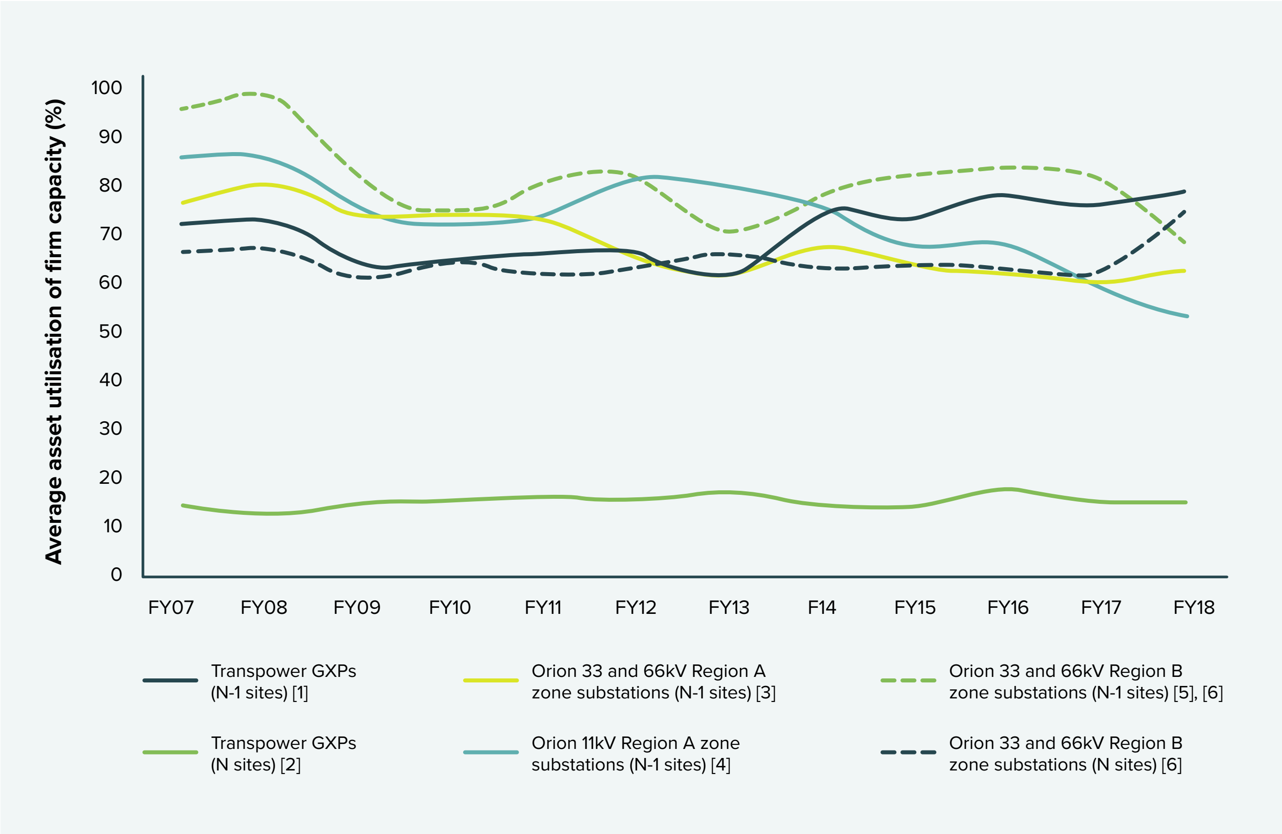
6.3.5 GXP and substation utilisation

For N-1 sites with dual transformers or parallel 11kV incomers, we calculate utilisation by dividing peak load by the N-1 capacity – capacity available following a single fault – of the site. Utilisation of 100% implies that further increases in load will require network investment or the security of supply will reduce.

For N security sites with single transformers and/or line or cable supplies, utilisation is calculated by dividing peak load by the installed site capacity. To provide support to neighbouring N security sites during contingencies it is not necessarily desirable to aim for 100% utilisation at these sites. Our interruptible irrigation load initiative has allowed an increase in utilisation of our Region B N security sites and utilisation of 70-80% is appropriate in this context.

Figure 6.3.16 shows the average asset utilisation of firm capacity.

Figure 6.3.16 GXP, 66kV, 33kV and 11kV zone substation utilisation



Notes:

1. Transfer Springston GXP to Islington FY14
2. Very small GXPs at Arthur's Pass, Castle Hill and Coleridge
3. Significant new capacity installed in FY12
4. Sites being decommissioned since FY15 & load transferred to neighbouring sites
5. Significant new capacity installed in FY09
6. Adjusted for sites that have moved from n to n-1

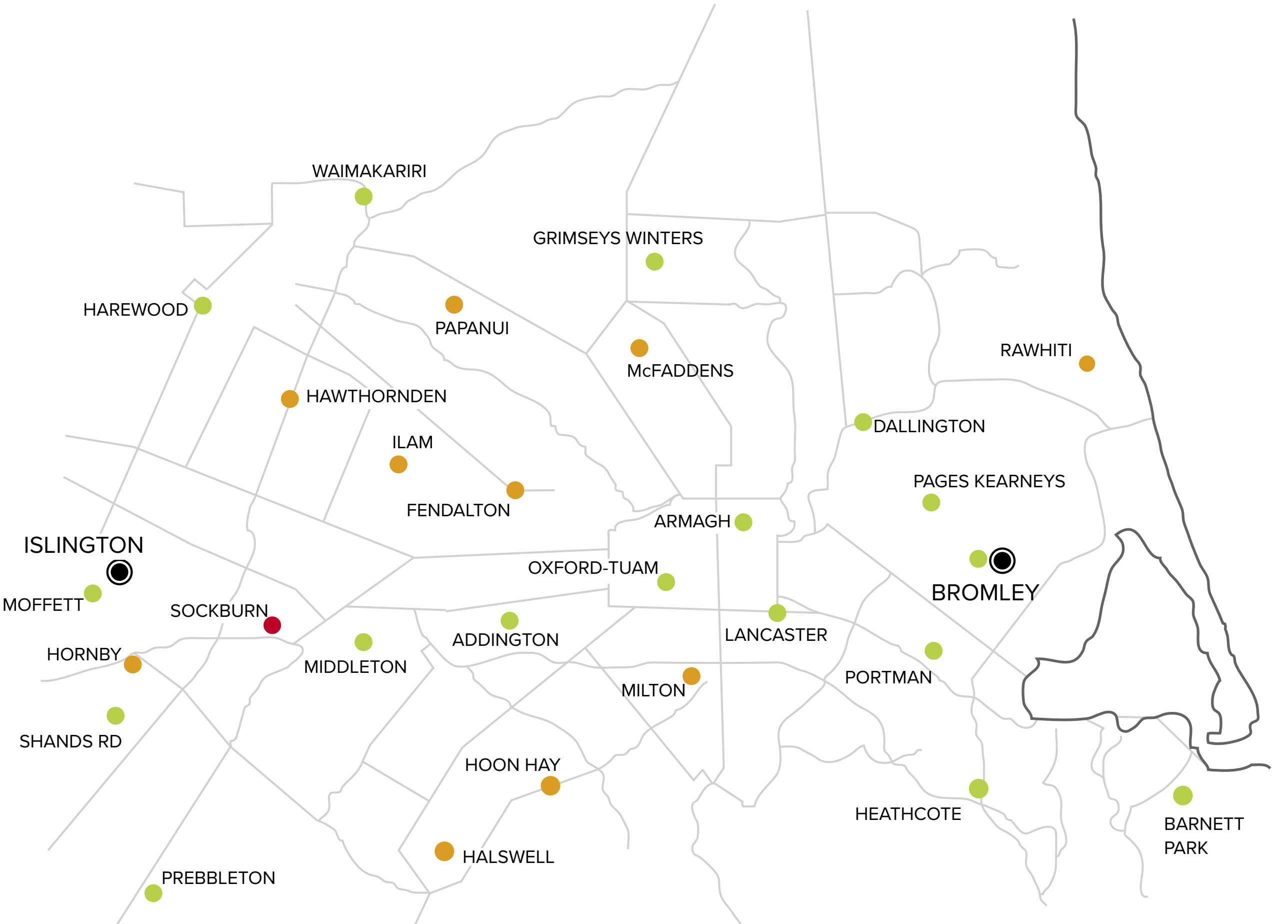
6.3.6 Present loading

Region A geographical map in Figure 6.3.17 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 the previous year are:

- Sockburn rose to more than 90% due to derating of the 33kV cable joints which are now on a refurbishment programme
- Halswell and Hornby rose to more than 70%
- Fendalton and McFaddens dropped to less than 90%
- Waimakariri firm capacity was restored due to having a second transformer which removed the 15MW limit in the security standard due to a single transformer.

Figure 6.3.17 Zone substations – Region A (FY18 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%

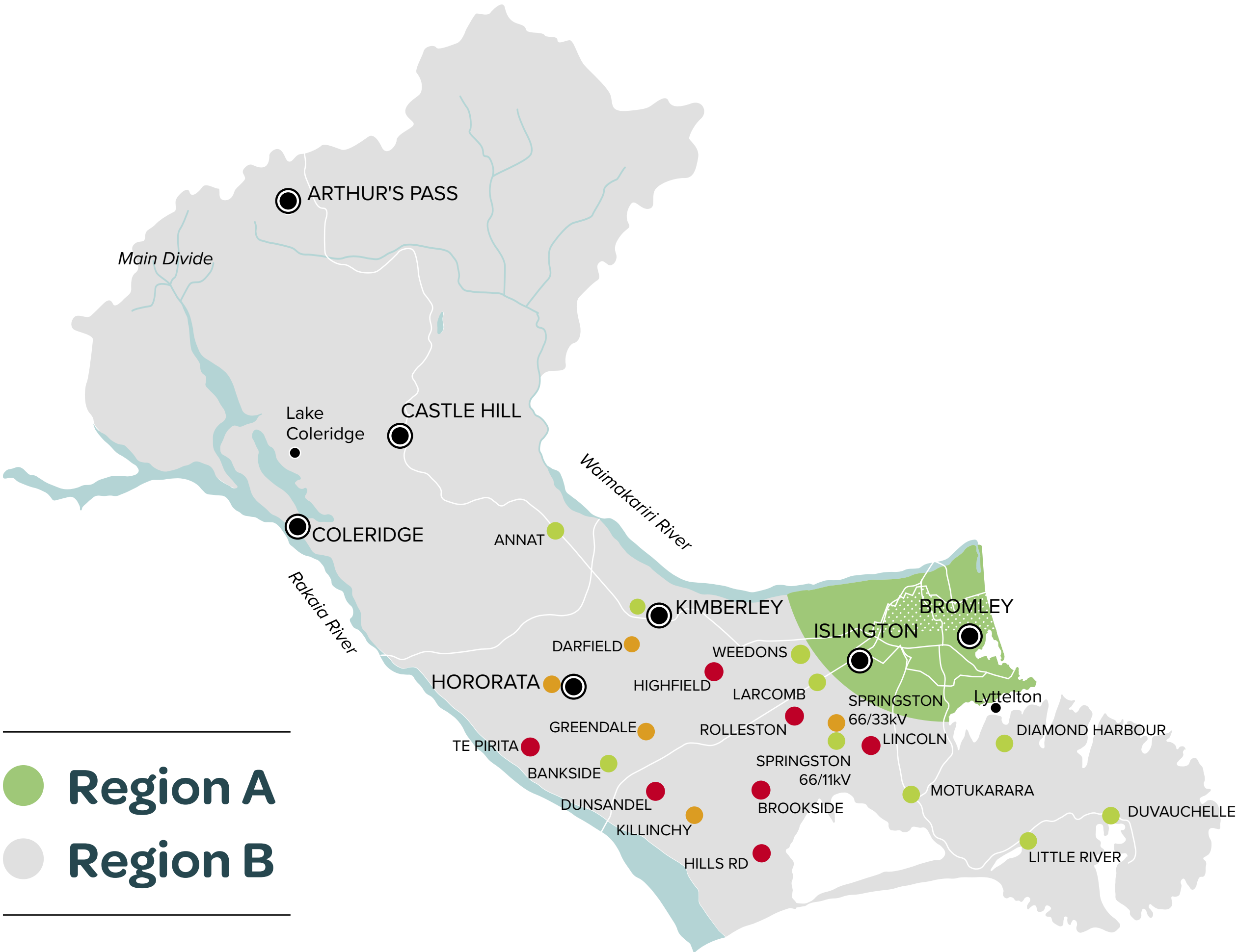
6.3 Preparing for growth continued

The Region B geographical map in Figure 6.3.18 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 the previous year are:

- Te Pirita, Hills and Brookside moved to more than 90%
- Darfield, Greendale and Hororata moved to more than 70%
- Springston moved to less than 70%.

Figure 6.3.18 Zone substations – Region B (FY18 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%

6.3.7 Load forecast

6.3.7.1 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 FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Bromley 66kV	A1	210	123	123	124	118	119	120	121	122	123	124	125	126
Islington 33kV	B1	107	72	71	72	74	76	79	82	84	85	87	88	90
Orion Islington 66kV	A1	494 [1]	430	428	443	453	478	486	495	500	505	510	515	521
Hororata 33kV [2]	C1	23	22	22	21	21	21	21	22	22	22	22	22	22
Kimberley 66kV, Hororata 66 & 33kV [3]	C1	70 [4]	64	67	67	68	68	75	75	75	75	75	74	74
Arthur's Pass	D1	3	0.3	0.3	0.3	0.3	0.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Castle Hill [5]	D1	3.75	0.7	0.8	0.8	0.8	0.8	0.8	0.8	5	6	6	7	7
Coleridge	D1	2.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Indicates load greater than firm capacity

Notes:

1. 532 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 66 if needed

3. Constraint to be resolved by new GXP

4. Assumes full generating capacity available from Coleridge. Can be limited to 40MW capacity when Coleridge is not generating or providing reactive support

5. Possible upgrade required for the proposed alpine village and winter sports resort near Porters Heights

6.3.7.2 Zone substation load forecasts

The following three 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 6.3.2 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 MVA	Actual winter FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Year 10 High EV Impact
Addington 11kV #1	B2	40	24	23	23	23	23	23	23	23	23	23	23	23	23
Addington 11kV #2	B2	34	13	20	21	21	21	21	21	21	21	21	22	22	23
Armagh	A3	40	12	18	19	22	22	23	24	24	25	25	26	27	29
Barnett Park	B3	15*	8	8	8	8	8	8	9	9	9	9	9	9	10
Bromley	B2	60	31	31	31	32	32	32	33	33	33	34	34	35	38
Dallington	B2	40	27	27	27	27	27	28	28	28	28	29	29	29	33
Fendalton	B2	40	37	34	34	34	34	34	34	34	34	34	34	35	38
Halswell	B2	23	17	18	19	20	21	22	23	24	24	25	25	26	30
Harewood	B3	7.5	2	2	2	2	2	2	2	2	2	2	2	2	2
Hawthornden	B2	40	31	30	30	30	31	31	31	31	31	31	31	31	35
Heathcote	B2	40	23	28	29	29	29	29	29	30	30	30	30	30	33
Hoon Hay	B2	40	35	33	33	34	34	34	34	35	35	35	36	36	38
Hornby	B3	20	14	14	15	15	15	15	16	16	16	16	17	17	17
Ilam	B3	11	8	8	8	8	8	8	8	8	8	8	8	8	9
Lancaster	A2	40	19	21	21	21	21	21	22	22	22	22	22	22	23
McFaddens	B2	40	35	35	35	35	35	36	36	36	36	36	37	37	41
Middleton	B2	40	23	24	25	25	25	24	24	24	24	24	24	24	24
Milton	B2	40	34	32	32	33	33	33	34	34	34	35	35	36	41
Moffett St	B3	23	12	14	14	15	16	18	20	20	21	21	22	22	22
Oxford-Tuam	A2	40	14	21	27	27	29	29	29	29	29	30	30	30	30
Papanui	B2	48	40	40	44	44	57	57	62	62	62	63	63	64	66
Prebbleton	B3	15	5	6	6	6	6	6	6	6	6	6	6	6	7
Rawhiti	B2	40	29	29	29	29	30	30	30	30	30	30	30	30	35
Shands Rd	B3	20	10	11	11	12	12	13	13	14	14	15	15	15	15
Sockburn	B2	29#	26	26	27	27	27	27	28	28	28	29	29	29	29
Waimakariri	B2	40	16	22	23	23	23	23	23	23	23	24	24	24	24

* Single transformer – security standard limits load to 15MW, 11kV ties from neighbouring sites provide backup capacity for all load

Cable limit 35MVA. 33kV joint issue temporarily limits each of the three cables to 14.3MVA i.e. N-1 is only 28.6MVA

Indicates load greater than firm capacity

Proposed resolution is as follows:

Halswell	Load transfer to Hoon Hay then a transformer upgrade
Ilam	Included with the 66 and 33kV substations although it is regarded as an 11kV zone substation elsewhere in this plan. This is because it has no transformers on site but has two dedicated 66/11kV transformers located at Hawthornden
Milton	Load transfer to Addington zone substation
McFaddens	Load transfers or new Marshland zone substation when needed
Papanui	Transfers to Waimakariri & new Belfast zone substation
Sockburn	33kV joint issue temporarily limits each of the three cables to 14.3MVA i.e. N-1 is only 28.6MVA. Resolve by transfer to Middleton until joints refurbished

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

Zone substation	Security Standard class	Firm capacity	Actual	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Year 10 High EV Impact
Annat*	C4	7.5	3.7	4	4	4	4	4	4	4	4	4	4	4	4
Bankside*	C3	10	5.8	5	5	5	5	5	5	5	5	5	5	5	5
Brookside*	C3	10	9.4	9	9	10	10	10	10	10	10	10	10	10	10
Darfield*	B3	8.8	6.2	6	6	6	6	6	6	7	7	7	7	7	7
Diamond Harbour*	B3	7.5	1.7	2	2	2	2	2	2	2	2	2	2	2	3
Dunsandel	A3	10	13.3	22	22	22	21	30	30	30	29	29	29	29	29
Duvauchelle	B3	7.5	5.1	5	5	5	5	5	5	5	5	5	5	5	5
Greendale*	C3	10	7.4	6	6	6	6	6	6	6	6	6	6	6	6
Highfield*	C3	7.5	6.8	6	6	6	6	6	6	6	6	6	6	6	6
Hills Rd*	B3	7.5	7.0	7	7	7	7	8	8	8	8	8	8	8	8
Hororata*	C3	10	8.0	8	7	7	7	7	7	7	7	7	7	7	7
Killinchy*	C3	10	8.9	9	9	10	10	10	10	10	10	10	10	10	10
Kimberley	A3	23	13.9	16	16	17	17	16	16	16	16	16	16	16	16
Larcomb	B3	23	11.6	13	14	15	18	18	19	19	20	22	22	22	25
Lincoln	B3	10	9.6	10	10	11	12	12	12	13	13	13	13	14	15
Little River*	C4	2.5	0.6	1	1	1	1	1	1	1	1	1	1	1	1
Motukarara	C4	7.5	2.2	2	2	2	2	2	2	2	2	2	2	2	2
Rolleston	B3	10	10.6	11	11	12	12	12	12	12	12	13	13	13	14
Springston 66/33kV	B2	60	45.6	39	40	41	43	44	45	46	47	47	48	48	53
Springston 33/11kV*	B3	10	5.7	6	6	7	7	7	7	7	7	7	7	8	8
Te Pirita*	C3	10	9.5	10	10	10	10	10	10	10	10	10	10	10	10
Weedons	B3	23	10.5	11	11	13	13	13	13	13	13	13	13	13	13

* Denotes single transformer or line substation

Indicates load greater than firm capacity

Proposed resolution as follows:

Dunsandel	One 23MVA transformer has been installed, with a second one due FY20, third added when needed
Hills Rd	Install transformer from Motukarara
Larcomb	Load shift to Rolleston if needed
Lincoln	Load shift to Springston where a second 10MVA transformer added when needed
Rolleston	Load shift to Larcomb, Weedons and Highfield, then new Burnham zone substation

Table 6.3.4 11kV zone substations – load forecasts (MVA)

Zone substation	Security Standard class	Firm capacity	Actual winter FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	Year 10 High EV Impact
Grimseys-Winters	B2	26.5	14	14	18	18	31	31	35	36	36	37	37	38	28
Pages-Kearneys	B4	17.2	9	9	9	9	9	9	9	9	9	9	9	9	9
Portman	B3	24	11	10	10	10	10	10	10	10	10	10	10	10	11

Indicates load greater than firm capacity

Proposed resolution as follows:
- Grimseys-Winters New Belfast zone substation

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 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.

Table 6.4.1 Network supply HV Security Standard

Security Standard Class	Description of Area or Customer type	Size of load (MW)	Cable, line or transformer fault	Double cable	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	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	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	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.

6.4.2 Network utilisation thresholds

We record loads on our zone substation 11kV feeder cables at half hour intervals. This information is used to prepare an annual reinforcement programme for our network. Reinforcements recommended in this plan are generally based on winter loading for the Christchurch metropolitan areas (Region A) and on summer loading for the Banks Peninsula and Canterbury Plains areas (Region B).

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 scheme.

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 ultimately results 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. 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, over, provides a summary of our standard network capacities.

Reinforcements recommended in this plan are generally based on winter loading for the Christchurch metropolitan areas (Region A) and on summer loading for the Banks Peninsula and Canterbury Plains areas (Region B).

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
		40-160	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	6	2	0.025-1	Up to 0.3
		30-50	interconnected network					
Region B	33	15	interconnected network	7.5-10	6	2	0.025-1	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 6MW 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 work flow 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 also 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 projects in the forthcoming 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 take into account 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.

We give priority to addressing constraints most likely to impact customer supply through extended or frequent outages, or compromised power quality.

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:

- Customer Demand Management
- Distributed Generation
- uneconomic connections

6.4.5.1 Customer Demand Management

Customer Demand Management provides an alternative to transmission and distribution network development.

Customer Demand Management is shaping the overall customer load profile to obtain maximum mutual benefit to the customer and the grid and network operator. This promotes efficient operation of the network.

Some of the gains from Customer Demand 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 Customer Demand 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

The recent and forecast improvement in battery technology, and forecast drop in price is likely to create new Customer Demand Management opportunities in the short to medium term. We will continue to monitor and investigate opportunities.

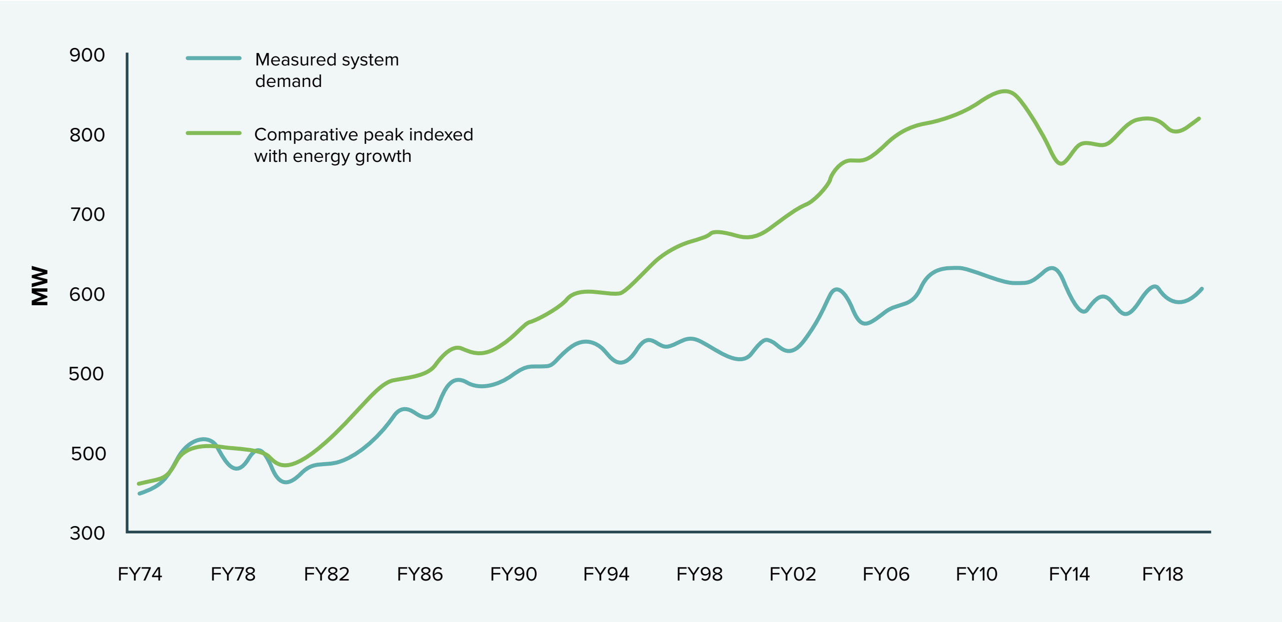
For some major projects, we would consider paying for Customer Demand Management to avoid or defer network development. These projects, and an indication of the value possible are detailed in Section 6.7.

Ripple control

Ripple control is one of the most effective tools available for implementing Customer Demand Management. Over the last 30 years, our commitment to Customer Demand Management through hot water cylinder peak control and night rate price signalling has resulted in a dramatic difference between the growth in peak demand and energy usage. Figure 6.4.1 shows that significant peak demand capping occurred during the 1990s as a result of our Customer Demand Management initiatives.

Customer Demand 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 Peak demand capping



Since 1980, Orion has achieved a gap of 200MW between energy based peak demand and measured peak demand. As network costs are driven by peak demand, this means growth in costs has been kept much lower than growth in demand. The decreased gap following the Canterbury earthquakes in 2011 and 2012 is due to the large drop in energy delivered due to the reduction in connections supplied. There was no drop in demand for the first two years following the earthquakes due to significant snow falls in August 2011 and June 2012. Committed utilisation of our ripple control system has been the driver for approximately 125MW of the 200MW gap between demand and energy.

Ripple control has facilitated the implementation of the following Customer Demand Management strategies:

- 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) – 25MW during contingencies. This has reduced 3MW with the decommissioning of ground water pumps due to the uptake of the Central Plains Water Scheme

To ensure we can continue to achieve these results, ripple plants have been replaced with multiple 11kV ripple plants. 11kV ripple plants avoid overloading issues caused by an increasing number of capacitors being installed on Transpower's grid and also reduce dependence on any one item of plant.

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.

Interruptible load groups – irrigation

When the power goes out on our network, there is a cost of lost production and inconvenience to our customers. Our consideration of network investments to improve SAIDI and SAIFI aims to match the cost of an interruption to the cost of preventing one.

We now plan our network on the basis that emergency cuts are acceptable to irrigators and as a result invest less in the rural network with accompanying reduced prices to irrigators.

Coordinated upper South Island load management

As well as controlling hot water cylinder load to manage peaks on our own network we also coordinate control 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 of the 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.

Power factor correction rebate

If a customer's load has a poor power factor then our network and the transmission grid is 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.

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

6.4.5.2 Distributed Generation

The purpose of our distribution network is 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 (DG). DG may also reduce the need to extend our network capacity.

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

- coincidence of DG 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 DG

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 connection – larger connections only – is submitted for review, we undertake an economic assessment of the connection. This assessment determines whether or not our standard pricing arrangements will cover the cost of utilising existing or new assets associated with the connection. If the connection is uneconomic, that is 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

Our 'deterministic' Security Standard provides a useful benchmark to identify areas on our network that may not currently receive the same high level of security as the majority of our network.

Economically robust solutions to actual and anticipated network gaps caused by imminent load growth are quickly provided for by our annual capital spend. Network security is maintained on our 11kV distribution network by ensuring that the design of new connections is consistent with our Security Standard.

The network gaps identified in Table 6.5.2 arise because the cost of reinforcing the network to the performance level identified in our Security Standard would be economically prohibitive. That is, the cost to provide the Security Standard level of performance would exceed what customers are prepared to pay for it.

In general, network security gaps fall into one or more of 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 for each network gap determines the Value of Lost Load (VoLL) when a defined contingency occurs and then utilises probability theory to determine the annual VoLL. This VoLL is calculated using $3 (residential) to $10 (industrial) per kW for the initial interruption, and $1 (irrigation) to $50 (commercial) per kWh thereafter.

Although the VoLL of contingencies can be very high, the low probability of occurrence can often lead to a very low annualised VoLL and therefore render the proposed solution uneconomic. This often results in the timing of the solution being largely dependent on the timing of other related network development proposals which are required for load growth or asset replacement in the area.

Because annualised VoLL figures can hide the high VoLL of a particular event it is important to consider the implications of rare but costly – High Impact Low Probability – events if they were to occur. The Canterbury earthquakes have underlined the importance of building a resilient network and any economic analysis should be considered alongside the asymmetric 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 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 Standard to Transpower's core-grid, spur or GXP assets.

Table 6.5.1 and Table 6.5.2 only show current Security 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

Network gap	VoLL per event $,000	VoLL p.a. $,000	Solution	Cost $,000	Cost p.a. $,000	Benefit cost ratio	Proposed date
Islington							
Partial loss of restoration for an Islington 220/33kV dual transformer failure	2,200	4	Install Templeton 66kV zone substation (Project 502) [1]	5,590	783	1:196	Timing is influenced by load growth at Templeton and not driven by closing this gap
Hororata							
Interruption to all Hororata GXP load for a 66kV bus fault (restorable)	830	19	Install a 66kV bus coupler (75% of load will remain on)	TP 500	55	1:2.9	Uneconomic. No date proposed. Proposed Norwood GXP will reduce the load making it even less economic
Partial loss of restoration for a Hororata 66/33kV dual transformer failure	1,180	11	Hororata 33kV switchgear is near end of life and a review of whether to exit 33kV is required. This security gap to be included in a future 33kV architecture review.				

[1] Shared mobile generation could provide an alternative solution.

6.5 Network gap analysis continued

Table 6.5.2 Network security gaps

Substation	Network gap	Solution	Cost $,000	Proposed date
Dallington	Loss of 27MW of load for a single 66kV cable or transformer failure. Restoration achievable in 5 minutes.	Complete a 66kV loop from Bromley via Rawhiti and Marshland by installing a cable from Marshland to McFaddens zone substation (Project 491).	8,222	FY22
Rawhiti	Loss of 29MW 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).	Investigate installation of a 33kV bus coupler as part of 33kV switchgear replacement	TBA	FY23
Waimakariri	Loss of 20MW of load for a single 66kV circuit	Complete a 66kV loop from Papanui via Belfast and Waimakariri by installing a cable from Belfast to Papanui (Project 942)	11,694	FY24
Lancaster	Loss of 21MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes.	Overall objective: complete a 66kV loop from Hoon Hay to Milton.		
		Lancaster ZS to Milton ZS 66kV (Project 589)	5,063	FY27
		Milton ZS 66kV switchgear for Lancaster ZS cable (Project 723)	5,090	FY27

6.6 Network development proposals

This section lists our proposals to remove capacity and security constraints. In addition to monitoring the actual rate of growth, we also consider the time it takes to plan and install the network identified as being needed. We allow for:

- sufficient time to procure zone substation land and/or negotiate circuit routes – typically one or two years
- sufficient time for detailed design – typically one year
- service provider resources managed via 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 Impact on service level targets

The network development projects listed in this section are driven mainly by the need to meet the capacity and security requirements of load growth. Where economic, project solutions have been designed to meet our security of supply standard requirements.

This ensures our network configuration and capacity is constructed in a consistent way and the impact on our reliability of supply service levels will be predictable. It should be noted that reliability of supply service levels are a function of many inputs and, while network configuration and capacity is a major input, it is not the only factor.

Project solutions also need to consider our safety, power quality, environmental and efficiency targets.

Safety performance during construction is influenced by factors such as site security, operating standards and contract management practices. Upon completion, high levels of safety performance are achieved by appropriate choice of network equipment, site security and operating standards.

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.

Power quality is influenced mainly by ensuring that network capacity is adequate. Undersized reticulation or high impedance transformers will increase the risk of power quality issues. Some projects provide for the connection of equipment (for example variable speed drives) which can create high levels of harmonic distortion and it may be necessary to install harmonic filtering equipment to reduce the distortion to acceptable levels.

Environmental targets are met with new projects by ensuring that substation design includes appropriate oil bunding and, where possible, precludes the installation of SF_6 switchgear. On-going environmental targets are met by adhering to appropriate resource management standards.

Our efficiency target is met by ensuring that upgrades or extensions to the existing network are not oversized. During development projects it may be necessary to reconfigure adjacent parts of the network and consideration is given to economic downsizing of existing underutilised distribution transformer capacity.

Projects for the current year can be considered firm. Those planned for the following four years will be reviewed annually, and may not proceed as currently envisaged. Projects for the remainder of the period are indicative only because of the uncertainties as to the nature and magnitude of future loads.

Power quality is influenced mainly by ensuring that network capacity is adequate.

6.6.2 Region A subtransmission development

We estimate one new Region A zone substation and a capacity increase of transformers at one substation in the next 10 years.

When required, we can connect most new loads to our network at short notice. The additional load makes use of network capacity held in reserve for contingency situations. That capacity must be replaced by capital expenditure in order to ensure that supply security continues to meet our Security Standard and the needs of our customers.

Each increment of between 20 and 40MW of new load requires a new zone substation. Zone substations supply an area close to them and free up capacity in adjacent substations. New zone substations require a suitable site, transformers, switchgear and subtransmission connected to Transpower's 66kV or 33kV GXPs.

We will consider removing 11kV zone substations when their assets come up for replacement, as they do not fit with our current network design architecture.

The capacity of our pre-earthquake 66kV subtransmission network north of Christchurch was not sufficient to supply any proposed new zone substation. Permanent damage sustained to our 66kV network from the earthquakes meant our network capacity was further reduced.

In an environment where our standard of living and health is so heavily dependent on a reliable electricity supply it has become increasingly important our network is resilient to a wide range of factors. The Canterbury earthquakes prompted the need to review the architecture of our network and our network security of supply standard and a reconsideration of the Christchurch subtransmission network was carried out in FY12.

We work hard to apply preventative maintenance measures to ensure that the likelihood of electrical, mechanical or external forces causing failure of our assets is economically minimised.

Future design will be based on a closed-ring network topology so the failure of any single route will not interrupt supply to a zone substation. Cables will be sized to give sufficient cross-GXP link capacity to provide full support in the loss of either Islington or Bromley 66kV supply. The preferred layout for 66kV zone substations is to have a ring-bus which has better fault performance than a conventional bus arrangement for either circuit breaker failures or bus faults.

For future work, we will continue to move away from zone substations being radially fed from GXPs to a more resilient layout.

In an environment where our standard of living and health is so heavily dependent on a reliable electricity supply it has become increasingly important our network is resilient to a wide range of factors.

Figure 6.6.1 Region A subtransmission 66kV – existing and proposed

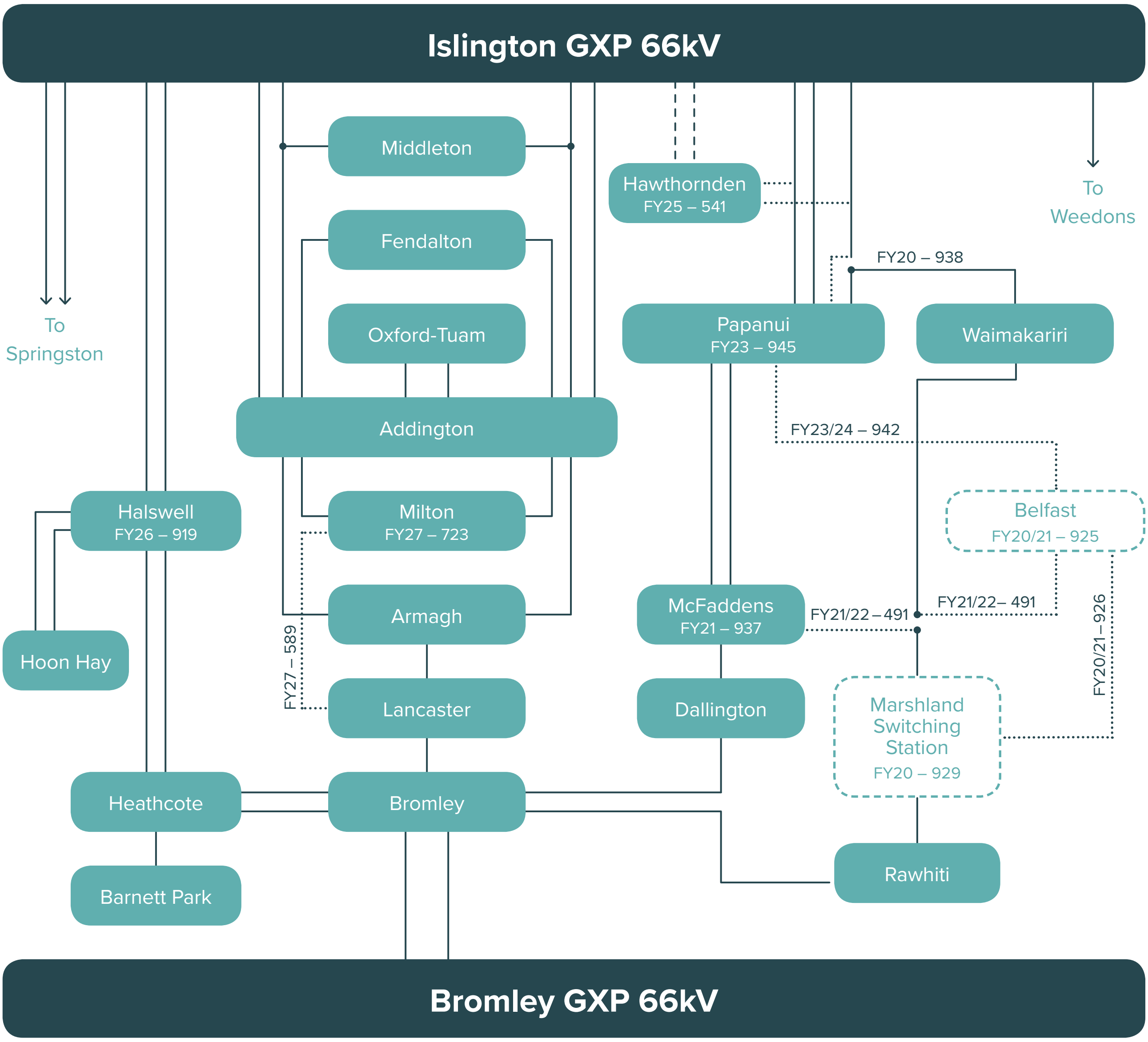
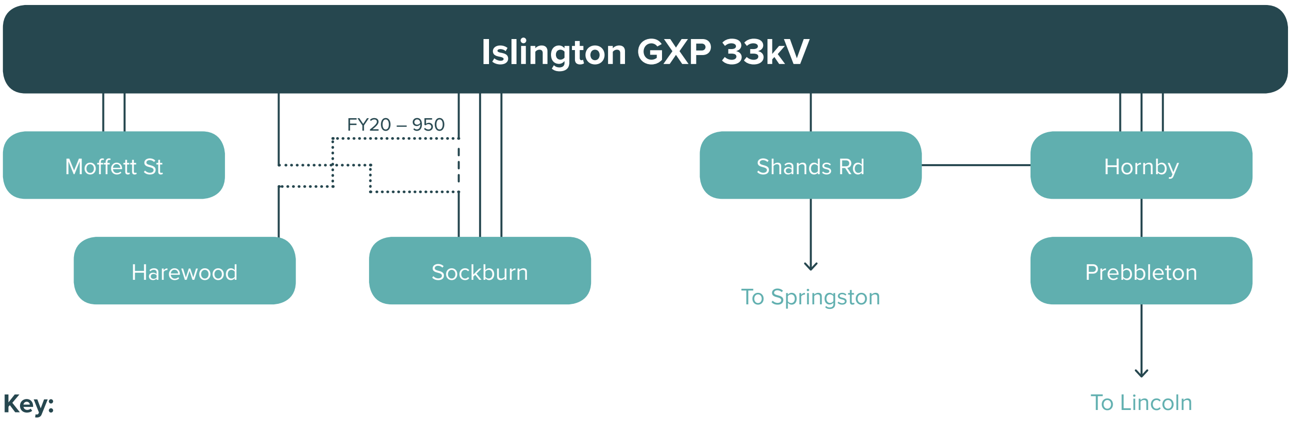


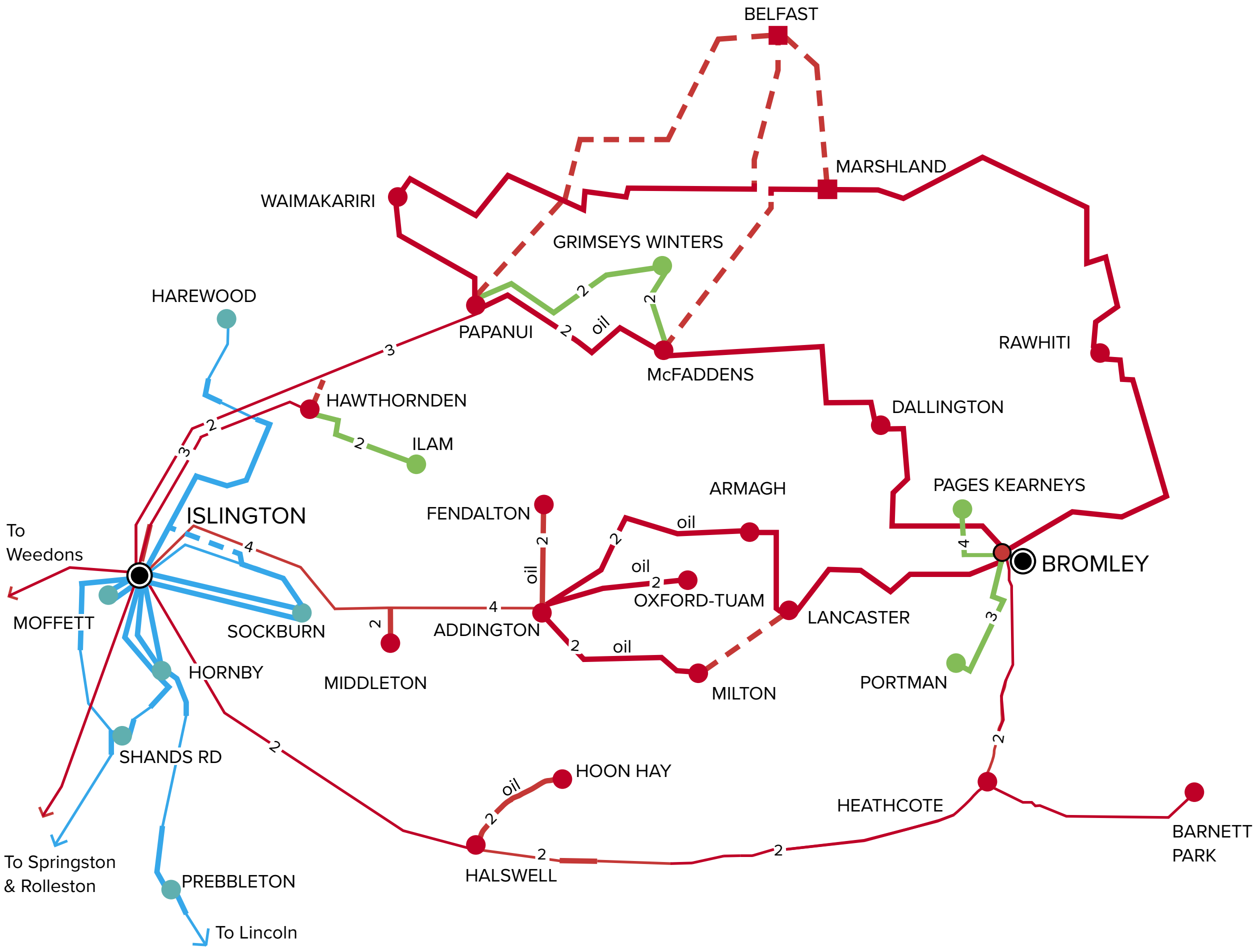
Figure 6.6.2 Region A subtransmission 33kV – existing and proposed



Key:

FY20 - 950	Year – Project	- - - - -	Existing circuit – to be decommissioned
···········	Proposed circuit		Existing zone substation
———	Existing circuit		Proposed zone substation

Figure 6.6.3 Region A subtransmission 66kV and 33kV – existing and proposed



Key:

Existing | **Proposed**

- 66/11kV zone substation
- 33/11kV zone substation
- 11kV zone substation
- 66kV overhead circuit
- 33kV overhead circuit
- 66kV underground circuit
- oil — 66kV underground circuit (oil)
- 33kV underground circuit
- 11kV underground circuit
- 2 — No. of circuits, if more than 1

Note: voltages are circuit/construction ratings

6.6.3 Region B subtransmission development

We estimate one new zone substation, the capacity increase of transformers at four zone substations and one new GXP in Region B in the next 10 years. This plan also makes provision for a new zone substation to connect customer distributed generation. However, the number, size, and location of these will depend on the magnitude and geographic distribution of actual load growth in the intervening period.

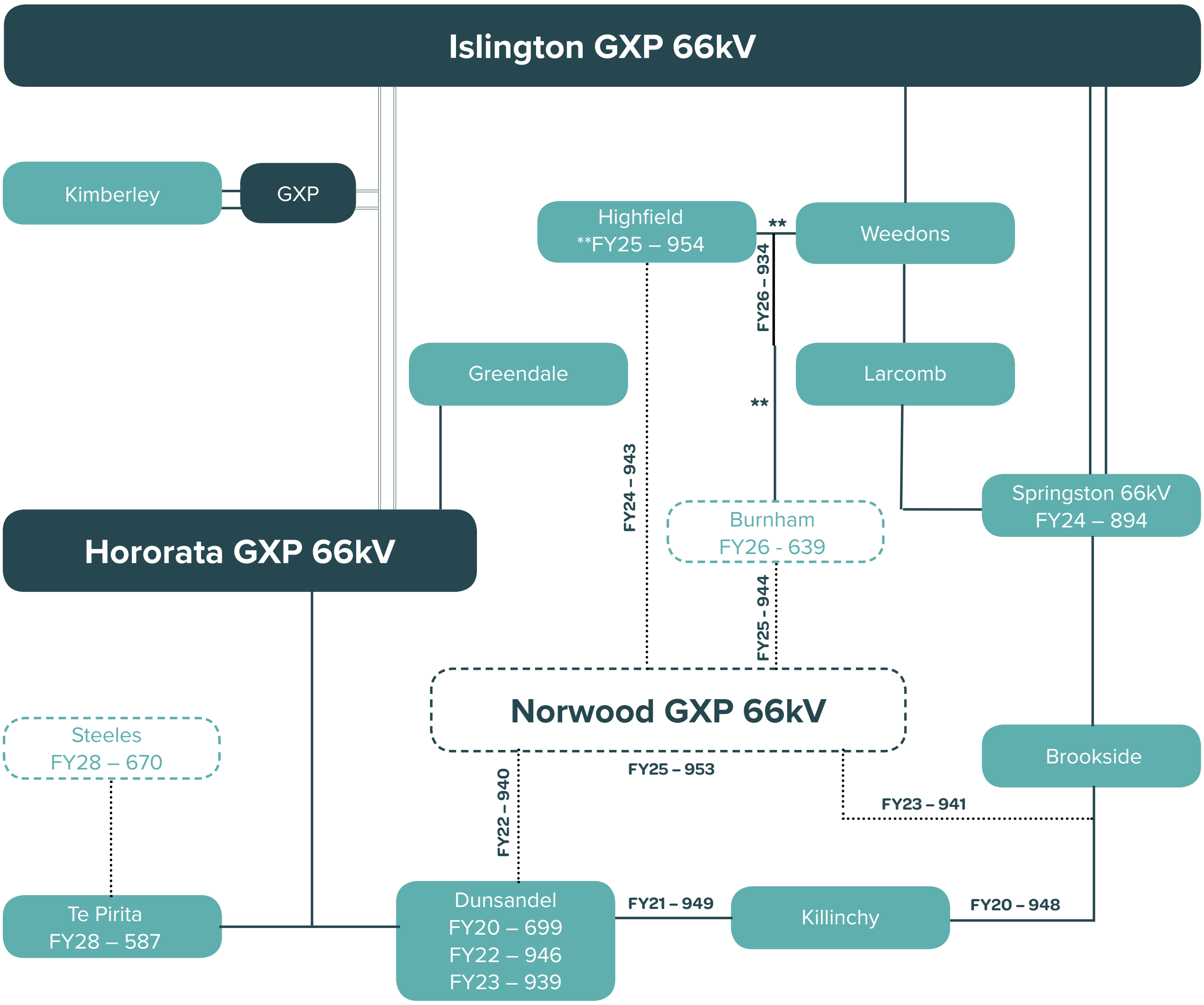
Each increment of between 5 and 20MW of new load requires a new zone substation. Zone substations supply an area close to them and free up capacity in adjacent substations. New zone substations require a suitable site, transformers, switchgear and subtransmission connected to Transpower's 66kV or 33kV GXPs.

The existing subtransmission network has been designed to meet strong load growth whilst optimising cost. The significant increase in load over the last 15 years has enabled a much more interconnected subtransmission network to be developed.

The number of zone substations operating in radial configuration has reduced over time. Most zone substations have only one transformer, generally 7.5MVA or 7.5/10MVA, although substations serving larger townships such as Rolleston and Lincoln or a milk processing plant may have duplicated transformers up to 23MVA.

Subtransmission capacity is generally limited by voltage drop considerations and hence 66kV, as opposed to 33kV, is technically and economically more attractive for new subtransmission projects.

Figure 6.6.4 Region B subtransmission network 66kV – existing and proposed



Key:

FY20 - 999 Year - Project

Proposed circuit

Existing circuit

Existing circuit – Transpower

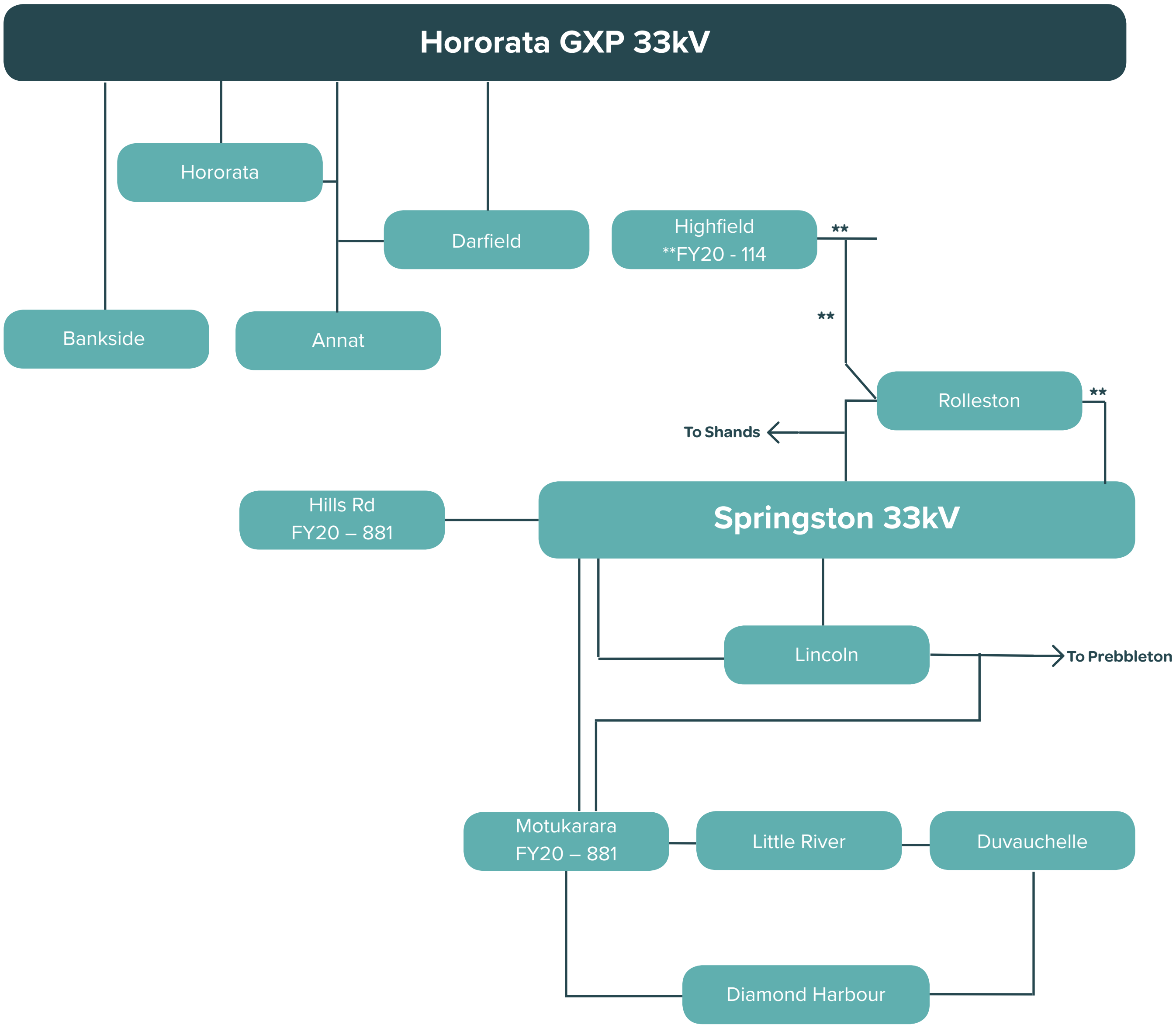
Existing zone substation

Proposed zone substation

** Built for 66kV, operating at 33kV until conversion

Proposed GXP

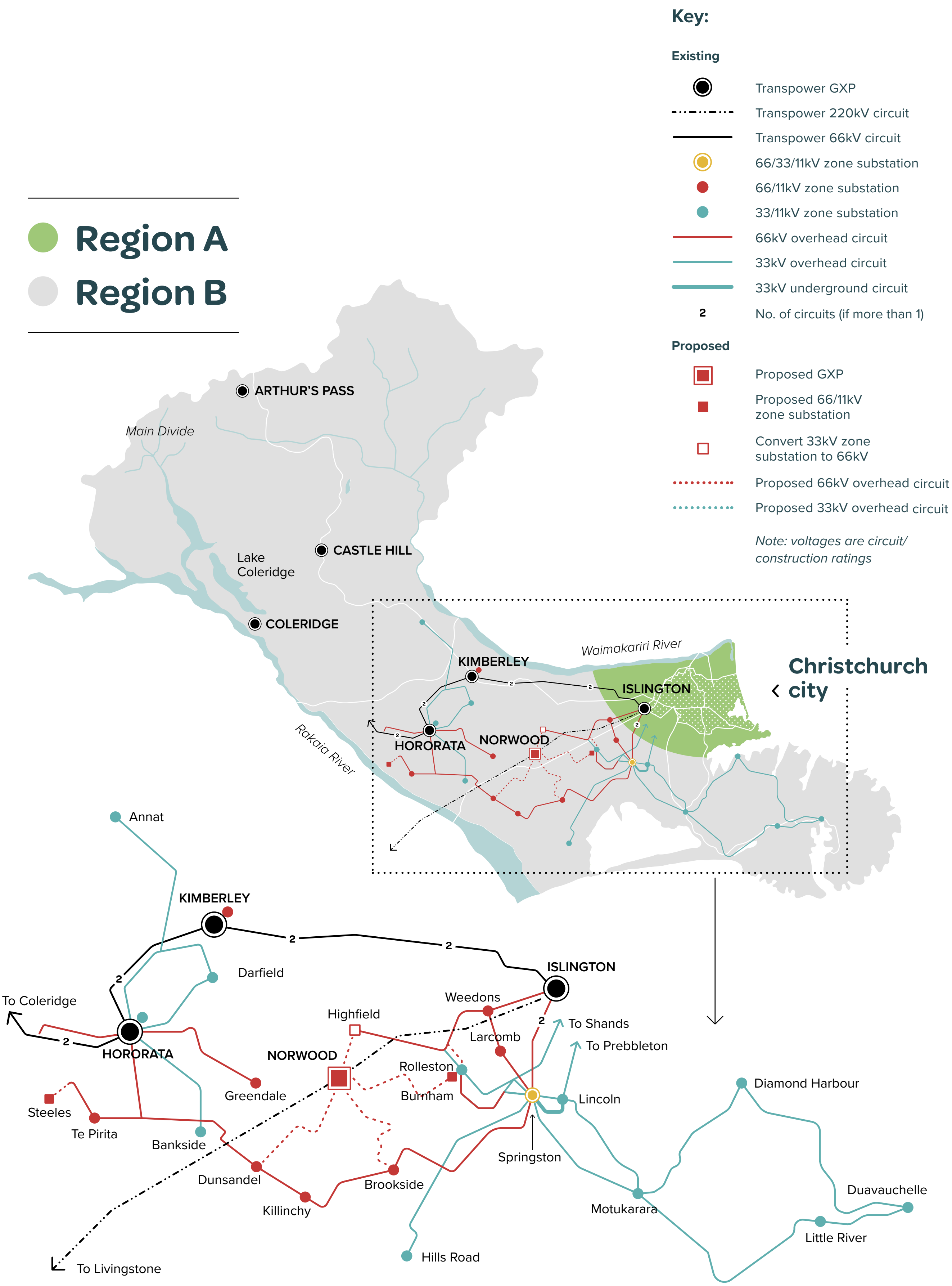
Figure 6.6.5 Region B subtransmission network 33kV – existing and proposed



Key:

FY20 - 999	Year - Project
———	Existing circuit
▬	Existing zone substation
**	Built for 66kV, operating at 33kV until conversion

Figure 6.6.6 Region B subtransmission network 66kV and 33kV – existing and future



6.6.4 Overview of projects and budgets

The network development/growth related projects and budgets identified in this section are sorted into the following categories:

- GXP major projects
- HV major projects
- HV minor projects
- LV projects
- network connectons and extensions.

With the exception of network connections and extensions, these categories are banded within the following timeframes:

- the current financial year (FY20) which are considered firm
- the next four years (FY21-FY24)
- the remainder of the period (FY25-FY29) indicative only.

FY refers to financial year ending 31 March.

6.6.5 GXP major projects

Table 6.6.1 shows an overview of the GXP major projects planned for the next 10 years.
The project values shown are indicative build costs for Transpower. The estimated Transpower new investment agreement payment schedule for these projects can be found in Table 9.1.14.

6.6.6 HV major projects

Table 6.6.2 shows an overview of these major projects planned for the next 10 years. Projects planned in the first year are considered firm.

HV Major projects are defined as those which are:

- new subtransmission, or
- significant (>$0.5m) subtransmission alterations.

Table 6.6.1 GXP Major projects – $000

No.	Project	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
931	Norwood GXP – new Region B 220/66kV substation				17,500						
	HV Major projects total				**17,500**						

Note: the details of this project can be found in Table 6.6.3.

6.6 Network development proposals continued

Table 6.6.2 HV Major projects – $000

No.	Project	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
881	Hills Rd ZS transformer upgrade	189									
948	Killinchy to Brookside 66kV upgrade	50									
950	Sockburn / Harewood 33kV feeders	548									
938	Papanui ZS 66kV bay	478									
114	Convert Highfield ZS to 66kV	392									
699	Dunsandel ZS upgrade – stage 2	2,130									
929	Marshland 66kV switching station	2,660									
926	Belfast ZS to Marshland 66kV cable	2,600	2,600								
925	Belfast ZS – new 66/11kV substation	4,397	4,397								
924	Belfast ZS 11kV feeder integration		417								
937	McFaddens ZS 66kV bay		478								
637	Railway Rd 11kV sub (Westland Milk)		3,360								
949	Dunsandel to Killinchy line upgrade		30								
491	Belfast / McFaddens 66kV cable links		4,111	4,111							
940	Norwood to Dunsandel 66kV line			2,820							
946	Dunsandel ZS 66kV line bay			493							
931	Norwood 66kV switching station			1,220	1,215						
939	Dunsandel ZS 3rd transformer				1,850						
941	Norwood to Brookside 66kV line				3,839						
945	Papanui 66kV bay for Belfast cable				478						
942	Belfast to Papanui 66kV cable				5,847	5,847					
894	Springston 2nd 66/11kV transformer					1,660					
728	Springston ZS 11kV switchboard ext.					580					
956	Strategic spare 40MVA transformer					1,410					
943	Norwood to Highfield 66kV line					1,085					
953	Norwood GXP 66kV line bays						946				
954	Highfield ZS 66kV line bay						478				
541	Hawthornden ZS 66kV T-off						1,616				
666	Porters village						4,600				
944	Norwood to Burnham 66kV line						3,037				
639	Burnham ZS - new 66/11kV substation							7,994			
919	Halswell ZS 3rd transformer							2,399			
934	Walkers Rd 66kV line conversion							160			
723	Milton switchgear for Lancaster cable								5,090		
589	Lancaster ZS to Milton ZS 66kV cable								5,063		
587	Te Pirita ZS 66kV bays									939	
670	Steeles Rd substation									2,989	
955	Strategic land purchase	400	400	400	400	400	400	400	400	400	400
	HV Major projects total	**13,844**	**15,793**	**9,044**	**13,629**	**10,982**	**11,077**	**10,953**	**10,553**	**4,328**	**400**

Table 6.6.3 HV Major project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
881	Hills Rd ZS transformer upgrade	The observed loading of Hills Rd ZS in summer FY18 was 7.0 MVA. Forecast load growth indicates the transformer capacity will be exceeded by FY23. Load transfer to the adjacent zone substations Killinchy and Brookside is not possible because they are at or approaching their full capacity	This project will involve swapping the existing 7.5MVA transformer at Hills Rd ZS with one of the units at Motukarara ZS. The new transformer will then be retro-fitted with cooling fans creating a 10MVA forced cooled unit.	The option of off-loading Hills Rd ZS was considered, but is not feasible due to lack of spare capacity at the surrounding zone substations. The option of purchasing a new higher capacity 33/11 kV transformer to meet the demand is undesirable due to long term plans for moving to 66kV in that area. The steady growth forecast for Hills Rd ZS and neighbouring sites makes diesel generation an unsuitable alternative to providing network capacity because of the increasing generator running hours. This would also require increasing fuel deliveries, which is at odds with the government's direction to reduce carbon emissions. Network scale battery storage is also unsuitable to this growth environment. Irrigation is the major driver for the peak load in the area and being climate dependant may lead to even longer peaks requiring significant storage.	189	FY20	Customers Safe, Reliable, Resilient System	Yes
948	Killinchy ZS to Brookside ZS 66kV line upgrade	Dunsandel ZS is supplied at 66kV from an overhead line tie between Hororata GXP and Springston ZS. The Springston ZS - Brookside ZS and Hororata GXP - Dunsandel ZS sections are rated at 43MVA, but the remaining sections (Dunsandel ZS - Killinchy ZS - Brookside ZS) are only rated at 30MVA. After load increases from Synlait and other rural customers, the total load on the tie is forecast to be 41 MVA in summer FY20 (excluding Te Pirita). Under contingency the Killinchy ZS to Brookside ZS line section rating will be exceeded. The forecast overload of the line needs to be addressed to provide N-1 security.	The existing 66kV line has been surveyed to determine that a higher rating can be achieved by increasing the separation between the 11kV line and overbuilt 66kV circuit. This will be achieved by a combination of dropping the 11kV cross-arms and elevating the 66kV at low clearance points.	This project is a tactical upgrade to lift the Killinchy ZS to Brookside ZS 66kV line maximum design temperature rating from 50degC (30MVA) to 70degC (43MVA).	50	FY20	Customers Safe, Reliable, Resilient System	Yes

Table 6.6.3 HV Major project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
950	Sockburn & Harewood ZS 33kV feeder reconfiguration	The Sockburn ZS T1 transformer capacity is limited to 14.2MVA due to the 33kV overhead line out of Islington 33kV ZS, limiting the nominal firm capacity of Sockburn ZS to 28.5MVA.	This project utilises the existing Harewood ZS T2 33kV cable from Islington ZS to the corner of Gilberthorpes Rd and Buchanans Rd to joint onto the existing Sockburn T1 cable using a new section of 33kV cable. The Harewood ZS T2 transformer will be connected onto the old Islington ZS to Sockburn ZS T1 overhead line. The Sockburn ZS firm capacity will be lifted to 35MVA with this change.	An alternative would be to extend the existing Sockburn ZS T1 33kV cable back to Islington ZS, but this would require over three times more cable than the current option.	548	FY20	Safe, Reliable, Resilient System	Yes
938	Papanui ZS 66kV bay	The Papanui ZS - Waimakariri ZS 66kV cable is terminated direct onto the Islington GXP - Papanui ZS 66kV Cct#1 tower circuit at bay 180 at the Papanui ZS 66kV switchyard. This configuration was originally conceived to eliminate the dependency on the Papanui 66kV busbar when there was no bus coupler to allow direct feed-through from Islington GXP to the 66kV northern loop. However this configuration causes protection and metering issues and the proximity of the earthing points to live equipment is non-compliant.	Utilise the spare Papanui ZS bay 160 to terminate the 66kV ISL - PAP Cct#1 tower line to separate the tower circuit from the Papanui ZS - Waimakariri ZS cable.	An alternative was to install a new line side VT at Papanui ZS on bay 180 to alleviate the metering and protection issues, but there are space constraints and this option would not address the non-compliant electrical safety clearance issues on bay 180 or the decreased circuit reliability.	478	FY20	Safe, Reliable, Resilient System Health and Safety	Yes
114	Convert Highfield ZS to 66/11kV	Highfield ZS is currently fed by an overhead 33kV line shared with Rolleston ZS from Springston ZS. During peak summer loads the Highfield ZS transformer reaches its maximum tap range due to voltage drop on the 33kV line and the contingency loading on the Rolleston ZS 33kV circuits are approaching capacity.	We propose to convert Highfield ZS from 33kV to 66kV by installing the ex Dunsandel ZS T2 7.5/10MVA transformer. Highfield ZS will then be supplied from the Weedons ZS 66kV bus.	This project will happen concurrently with the transformer swap at Dunsandel ZS. The line from Weedons ZS to Highfield ZS has already been re-insulated to 66kV.	392	FY20	Safe, Reliable, Resilient System	Yes

Table 6.6.3 HV Major project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
699	Dunsandel ZS upgrade - stage 2	In FY19/20 the Dunsandel ZS load will exceed the substation firm capacity due to strong industrial growth. The Dunsandel ZS upgrade - stage 1 provided N security to enable to the load to be connected, but there is no N-1 capability due to insufficient transformer capacity and excessive subtransmission voltage drop.	The Dunsandel ZS T1 transformer was replaced with a 23MVA unit in FY19 so this project will change the second transformer giving the substation a firm 23MVA transformer capacity. The project budget also includes the installation and commissioning of the four 2.5MVAr statcom units that will provide voltage support to the subtransmission network enabling the full thermal rating to be utilised.	The solution chosen was the most optimal for the large industrial customer with regards to capacity and project timing requirements. The existing 10MVA transformer will be installed at Highfield ZS (Project 114).	2,130	FY20	Customers Safe, Reliable, Resilient System	No
929	Marshland 66kV switching station	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).	This project is to establish a 66kV switching station at the Marshland ZS site to allow for the connection of the new 66kV cable (project 926) that will supply Belfast ZS (project 925) while maintaining the 66kV connectivity between Waimakariri ZS and Rawhiti ZS.	There are no other practical ways to supply Belfast ZS at 66kV without comprising the supply to existing zone substations.	2,660	FY20	Customers Safe, Reliable, Resilient System	Yes
926	Belfast ZS to Marshland substation 66kV cable	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).	This project is to establish a 66kV cable link between the Marshland 66kV switching station (project 929) and Belfast ZS (project 925).	There are no other practical ways to supply Belfast ZS at 66kV without comprising the supply to existing zone substations.	5,200	FY20-21	Safe, Reliable, Resilient System	Yes
925	Belfast ZS - new 66/11kV substation	The load forecast for Northern Christchurch shows at least 7MW of residential and industrial growth in the next 10 years. A rest home, shopping complex, business park development and water bottling plants may drive this higher. We have forecast a further 16MW of growth from water bottling. 11kV capacity in the area has been fully committed and both neighbouring zone substations are highly loaded. The CCC district plan presents Belfast as a priority area for business development and significant growth is likely when the new northern motorway is constructed. This area is growing faster than the Marshland area. Building Belfast zone substation enables the planned Marshland zone substation to be delayed beyond 10 years whilst still significantly enhancing the capacity and security of supply for customer in northern Christchurch city.	Establish a new 40MVA 66/11 kV zone substation in Belfast to supply load growth in Northern Christchurch.	It is not practical to supply the load growth using 11kV from existing zone substations or the previously proposed Marshland ZS due to the distribution reinforcement required. Customer demand management and/or diesel generation are better suited to deferring investment in a slowly developing load environment. The higher growth rate expected in Belfast means it is not a good candidate.	8,794	FY20-21	Customers Safe, Reliable, Resilient System	Yes

Table 6.6.3 HV Major project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
924	Belfast ZS 11kV feeder integration	The existing 11kV distribution network in Northern Christchurch requires reconfiguration to connect the new Belfast ZS (project 925) into it.	This project connects the existing Belfast 11kV primary ring network into the new Belfast ZS.	Completion of this project and Project 491 are required to provide full N-1 66kV security to Dallington ZS and Rawhiti ZS.	417	FY21	Safe, Reliable, Resilient System	Yes
937	McFaddens ZS 66kV bay	McFaddens ZS requires an extra bay to terminate the new McFaddens ZS - Marshland 66kV switching station cable (project 491).	This project is to install and commission a new 66kV CB bay at McFaddens ZS to terminate the new McFaddens ZS - Marshland switching station 66kV cable link into.	Completion of this project and Project 491 are required to provide full N-1 66kV security to Dallington ZS and Rawhiti ZS. The completion of the 66kV ring from Bromley 66kV facilitates the ability to transfer McFaddens ZS between Islington and Bromley GXP whilst maintaining full N-1 security.	478	FY21	Safe, Reliable, Resilient System	Yes
637	Railway Rd 11kV substation (Westland Milk)	The proposed Westland Milk Products (WMP) processing plant in the Izone industrial park will require up to 8MVA. Steady load growth around this district also means further 11kV reinforcement is necessary to maintain security of supply.	We will build an 11kV substation at the site with two dedicated cables from Larcomb ZS and a backup circuit from Rolleston ZS, all along Jones Rd.	The magnitude of the point load, plus the ongoing growth around Rolleston, meant that a new zone substation near WMP was considered as an option. The fact that there are three nearby substations with sufficient capacity (especially after Rolleston ZS is converted to 66kV), and that the 11kV feeders to adjacent substations in this project would still be needed for contingent support, means an 11kV solution is much cheaper and makes more efficient use of existing assets.	3,360	FY21	Customer Safe, Reliable, Resilient System	TBC
949	Killinchy ZS to Dunsandel ZS 66kV line upgrade	Under contingency the Dunsandel ZS to Killinchy ZS 66kV line rating will be exceeded. The forecast overload of the line needs to be addressed to provide N-1 security. See project 948 for further detail.	The existing 66kV line has been surveyed to determine that a higher rating can be achieved by increasing the separation between the 11kV line and overbuilt 66kV circuit. This will be achieved by a combination of dropping the 11kV cross-arms and elevating the 66kV at low clearance points.	This project is a tactical upgrade to lift the Dunsandel ZS to Killinchy ZS 66kV line maximum design temperature rating from 50degC (30MVA) to 70degC (43MVA).	30	FY21	Customer Safe, Reliable, Resilient System	Yes

Table 6.6.3 HV Major project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
491	Belfast ZS to McFaddens ZS 66kV cable links	Initially only a single 66kV cable connection will supply the new Belfast ZS (project 925) providing only N security. Rawhiti ZS and Dallington ZS remain with only switchable N-1 security at 66kV.	This project establishes 66kV cable links from Belfast ZS to Waimakariri ZS and from Marshland 66kV switching station to McFaddens ZS. This will provide Dallington ZS and Rawhiti ZS with full N-1 security and provide Belfast ZS with switchable N-1. The Marshland 66kV switching station - McFaddens ZS link also requires an additional 66kV CB bay (Project 937).	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	8,222	FY21-22	Safe, Reliable, Resilient System	Yes
940	Norwood GXP to Dunsandel ZS 66kV line	The existing 66kV subtransmission supplying Dunsandel ZS has no capacity available for any additional load growth.	This project provides a direct 66kV connection between the new Norwood GXP (project 931) and Dunsandel ZS.	Refer to Norwood GXP (project 931).	2,820	FY22	Customers	Yes
946	Dunsandel ZS 66kV line bay	A new 66kV CB bay is required at Dunsandel ZS to connect the new 66kV line from Norwood GXP.	This project creates a new 66kV bay to terminate the new 66kV line (project 940) from Norwood GXP (project 931).	Refer to Norwood GXP (project 931).	493	FY22	Safe, Reliable, Resilient System	Yes
931	Norwood 66kV switching station Norwood GXP - new Region B 220/66kV substation	Continued residential and commercial growth around the areas of Rolleston, Lincoln and Springston will cause load on the Islington GXP – Weedons ZS – Larcomb ZS – Springston ZS 66kV loop to exceed the firm capacity by FY27. The combined load on Islington 66kV GXP is also forecast to exceed firm capacity in FY27. The 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 constraints.	Install a new 220/66kV GXP at Norwood that is supplied from the Transpower Islington to Livingstone 220kV circuit. This will remove the constraint on the Islington GXP - Weedons ZS - Larcomb ZS - Springston ZS 66kV loop and along with increasing resilience of Orion's western network by reducing reliance on Islington 66kV GXP.	There are other 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.	2,435 17,500	FY22-23 FY23	Customers Safe, Reliable, Resilient System	Yes
939	Dunsandel ZS 3rd transformer bank	The load at Dunsandel ZS is forecast to exceed the firm capacity in FY23.	To meet the Orion security of supply standard a third 23MVA 66/11kV transformer will be installed at Dunsandel ZS.	Upgrading Dunsandel to a 2x 40MVA transformer site was considered but ruled out due to the need to upgrade the switchgear busbar and incomers.	1,850	FY23	Customers Safe, Reliable, Resilient System	Yes
941	Norwood GXP to Brookside ZS 66kV line	Dunsandel ZS load has grown (Project 939) beyond the N-1 capability of the existing subtransmission network so an additional supply from Norwood GXP is required.	This project provides a 66kV connection between Norwood GXP (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.	An alternative would be to double circuit the direct Norwood GXP to Dunsandel ZS 66kV line, but this arrangement is vulnerable to a single car vs pole incident.	3,839	FY23	Customers Safe, Reliable, Resilient System	Yes

Table 6.6.3 HV Major project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
945	Papanui ZS 66kV bay for Belfast ZS cable	Currently, Waimakariri ZS and Belfast ZS do not have full N-1 security at 66kV. Cable links are being created (project 942) but require a new 66kV at Papanui to connect to.	This is part of the project to create 66kV ties between Belfast ZS to Waimakariri ZS and from Belfast ZS to Papanui ZS.	Belfast ZS and Waimakariri ZS will have full N-1 security at 66kV on completion of these cable links and Project 942.	478	FY23	Safe, Reliable, Resilient System	Yes
942	Belfast ZS to Papanui ZS 66kV cable	Currently, Waimakariri ZS and Belfast ZS do not have full N-1 security at 66kV.	This project creates a 66kV cable link between Belfast ZS to Papanui ZS.	Belfast ZS and Waimakariri ZS will have full N-1 security at 66kV on completion of this cable link and Project 945.	11,694	FY23-24	Safe, Reliable, Resilient System	Yes
894	Springston ZS 2nd 66/11kV transformer bank	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).	We will increase the capacity by installing a second 66/11kV 10MVA transformer and additional 66kV CB bay.	There is an alternative to upgrade Lincoln ZS to be a 2x 23MVA substation but the chosen solution is more cost effective.	1,660	FY24	Customers Safe, Reliable, Resilient System	Yes
728	Springston ZS 11kV switchboard extension	At Springston ZS additional 11kV circuit breakers are required to connect the new 66/11kV transformer (Project 894).	This project extends the 11kV CB's installed in FY18 to terminate the new transformer and provide additional feeders.	The old 11kV CB's located in the aging modular building will be decommissioned as part of this project, rationalising the 11kV panel switchgear to one building.	580	FY24	Customers Safe, Reliable, Resilient System	Yes
956	Strategic Spare 40MVA transformer	At present the emergency spare 40MVA transformer is an in-service unit at Lancaster ZS, but in the short-term one of the transformers located at the future Belfast ZS (project 925) will become the new spare. Belfast ZS will be commissioned with two 40MVA transformers in FY21, but it is predicted that the load will grow requiring full uninterrupted N-1 around FY24.	This project is the purchase of a spare 20/40MVA 66/11kV power transformer. This transformer will be located at the future Marshland 66kV switching station (project 929).	This purchase and timing are dependant on the outcome of the replacement 66/11kV 40MVA transformer being purchased in FY19/20 and the load uptake at Belfast ZS.	1,410	FY24	Customers Safe, Reliable, Resilient System	TBC
943	Norwood GXP to Highfield ZS 66kV line	The load on the Islington GXP - Weedons ZS - Larcomb ZS - Springston ZS 66kV loop and Islington 66kV GXP transformers are forecast to exceed the N-1 capacities in FY27.	This project creates a new 66kV connection between Norwood GXP and Highfield ZS which forms one leg of the Norwood GXP - Highfield ZS - Burnham ZS 66kV loop to enable the new Rolleston ZS (Burnham ZS) to be fed from Norwood GXP. See projects 953, 954, 944 and 934.	The timing of this project is to ensure the resource required to construct the final solution is smoothed-out over several years.	1,085	FY24	Safe, Reliable, Resilient System	TBC

Table 6.6.3 HV Major project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
953	Norwood GXP 66kV line bays	New 66kV CB bays are required at Norwood GXP to supply the Norwood GXP - Highfield ZS - Burnham ZS 66kV ring.	This project installs two new 66kV line bays at Norwood GXP to allow for the connection of the new 66kV lines to Highfield ZS and Burnham ZS. See projects 946, 931, 943 and 954.	The timing of this project is to ensure the resource required to construct the final solution is smoothed-out over several years.	946	FY24	Safe, Reliable, Resilient System	TBC
954	Highfield ZS 66kV line bay	A new 66kV CB bay is required at Highfield ZS to connect the new 66kV line from Norwood GXP.	This project installs a new 66kV line bay at Highfield ZS to allow for the connection of the new 66kV line from Norwood GXP. See projects 946, 931, 943 and 953.	The timing of this project is to ensure the resource required to construct the final solution is smoothed-out over several years.	478	FY25	Safe, Reliable, Resilient System	TBC
541	Hawthornden ZS 66kV T-off	The radial configuration of the 66kV lines from Islington 66kV GXP to Hawthornden ZS does not enable supply route diversity to be achieved. Furthermore, the purchase of the Papanui substation 66kV lines provides an opportunity to rationalise and more efficiently supply Hawthornden ZS/Ilam ZS.	We intend to supply Hawthornden ZS and Papanui ZS from the three Islington GXP to Papanui ZS high capacity tower lines enabling the ability to supply Hawthornden ZS/Ilam ZS from the Papanui ZS 66kV bus. We will then be able to decommission the lower capacity Islington GXP to Hawthornden ZS tower lines and rationalise the connection assets at Islington 66kV GXP.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	1,616	FY25	Safe, Reliable, Resilient System	TBC
666	Porters Village	A large resort development near Porters Pass ski field is proposed and if it proceeds it will require connection to the network. Existing electrical load at the site is supplied by 'off grid' generators.	The size of the load and distance from existing assets makes the requirement challenging. Preliminary studies have been undertaken to provide an initial estimate of the costs however detailed design is yet to be undertaken. The solution may involve major business decisions such as GXP changes or the adoption of 22kV assets.	The size of the load and distance from existing assets makes the requirement challenging. Preliminary studies have been undertaken to provide an initial estimate of the costs however detailed design is yet to be undertaken. The solution may involve major business decisions such as GXP changes or the adoption of 22kV assets.	4,600	FY25	Customers	TBC

Table 6.6.3 HV Major project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
944	Norwood GXP to Burnham ZS 66kV line	A full N-1 66kV supply will be required at the planned Burnham ZS (Project 639) due to the existing load on Rolleston ZS	This project creates a new 66kV link between Norwood GXP (project 931) and Burnham ZS (project 639) forming part of the 66kV subtransmission loop Norwood GXP – Highfield ZS – Burnham ZS. This provides Burnham ZS with a full N-1 loop out of Norwood GXP.	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 address the Islington GXP – Weedons ZS – Larcomb ZS – Springston ZS 66kV loop or Islington GXP 66kV capacity constraints.	3,037	FY25	Safe, Reliable, Resilient System	TBC
639	Burnham ZS - new 66/11kV substation	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).	A new 66/11kV 23MVA capacity Burnham ZS will be built to replace the 11kV capacity at Rolleston ZS.	Upgrading Rolleston ZS to 23MVA utlising 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.	7,994	FY26	Customers Safe, Reliable, Resilient System	TBC
919	Halswell ZS 3rd transformer bank	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.	This project is the installation of an additional 23MVA 66/11kV transformer to lift the firm capacity from 23MVA to 46MVA and 66kV CB bay to supply it. Additional 11kV feeders will be installed to enable the use of the extra capacity	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	2,399	FY26	Customers Safe, Reliable, Resilient System	TBC
934	Walkers Rd 66kV line conversion	The overhead 33kV conductor between Highfield ZS and Rolleston ZS has progressively been upgraded to 66kV construction in anticipation of their operation at 66kV. However, there is a small section remaining down Walkers Rd that has yet to be upgraded.	This project converts the remaining 33kV line construction, down Walkers Rd, between Two Chain Rd and Kerrs/Wards Rd, to 66kV construction. The final construction will be 66kV Dog ACSR at 70degC (43MVA).	The timing of this project coincides with the requirement to create a 66kV ring out of Norwood GXP to supply the new Burnham ZS (Projects 943, 944 and 639).	160	FY26	Safe, Reliable, Resilient System	TBC

Table 6.6.3 HV Major project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
723	Milton ZS 66kV switchgear for Lancaster ZS cable	The Milton ZS to Lancaster ZS 66kV cable (Project 589) will require switchgear installation at Milton ZS.	This project commissions a new indoor 66kV switchroom on land adjacent to Milton ZS.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16 Network Architecture Review: Subtransmission.	5,090	FY27	Safe, Reliable, Resilient System	TBC
589	Lancaster ZS to Milton ZS 66kV cable	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.	A 95MVA circuit between Lancaster and Milton zone substations will provide extra security of supply for the CBD. In addition, it contributes our goal of providing for stronger cross-city connections between Islington and Bromley 220kV GXPs to mitigate a major outage at either site. See Project 723.	This project forms part of Orion's urban subtransmission strategy. For more detail refer to the document NW70.60.16.	5,063	FY27	Safe, Reliable, Resilient System	TBC
587	Te Pirita 66kV bays	The Central Plains Water scheme will create an opportunity for a 7MVA hydro generation scheme near Steeles Rd. Assets will be required to connect this into our 66kV network (see Project 670).	Two 66kV circuit breaker bays will be installed at Te Pirita for the existing Hororata circuit and the Steeles Rd line. If the generator does not proceed, these bays will still be required when the Windwhistle (Project 348) and/or The Point (Project 608) substations are commissioned.	It may be possible to connect the generation at 11kV. We will investigate this in more detail when more information is available.	939	FY28	Customers	TBC
670	Steeles Rd substation and 66 kV line	The Central Plains Water scheme will create an opportunity for a hydro generation scheme near Steeles Rd. Assets will be required to connect this into our 66kV network.	A dedicated substation may be installed at the generation site. The substation would be a simple voltage step up site without the need for a building to house 11kV switchgear, ripple and the usual protection and control equipment. We will build a 66kV line from this substation to Te Pirita zone substation. Switchgear will be required at Te Pirita (Project 587).	This project is dependent on the requirements of Central Plains Water or another party developing hydro generation at the site. Smaller amounts of generation could be directly connected to our 11kV network and therefore prevent the need for a new substation.	2,989	FY28	Customers	TBC
955	Strategic land purchase	Future HV projects related to zone substations and the subtranmission may require land aquistion to enable site expansion and reconfiguration	This is a yearly budget for strategic land purchases. Any land required will be identified as part of the proposed projects		400 / yr	FY20-29 ongoing	Customers Safe, Reliable, Resilient System	TBC

6.6.7 HV minor projects

Table 6.6.4 is an overview of minor projects planned for the next 10 years whereby projects planned in the first year are considered firm. For years that do not have projects scheduled, a lump-sum is allocated in the budget and projects will be identified closer to date.

Table 6.6.4 HV minor projects – $000

No.	Project	FY20	FY21	FY22-29
855	Waterloo Rd 11kV feeders	697		
536	Heathcote to Lyttelton 11kV reinforcement	1,200		
936	Terrace Rd 11kV overhead reinforcement	359		
932	Pound Rd 11kV reinforcement	92		
933	Lancaster ZS to Milton ZS 11kV tie	274		
922	Milton ZS 11kV alteration		366	
952	Addington 11kV reinforcement		249	
663	Darfield Township reinforcement		595	
920	Southfield Drive cable upgrade		371	
913	Heathcote Lyttelton reconfiguration		232	
	HV minor projects	**2,622**	**1,813**	**–**
	Unscheduled HV minor projects	878	900	900 / yr
	Unidentified HV minor projects	-	787	2,600 / yr
	HV minor projects totals	**3,500**	**3,500**	**3,500/yr**

6.6 Network development proposals continued

Table 6.6.5 summarises minor projects for the next 10 years. Business cases consider innovations and identify multiple solutions for implementation. Only the chosen solution is presented in this table.

Table 6.6.5 HV minor project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
855	Waterloo Road 11kV feeder	The load of the Waterloo Business Park off Waterloo Road in Hornby is forecast to grow as more of the lots are filled. This growth will stretch the 11kV capacity from Moffet ZS in the north eastern part of the business park.	To improve the 11kV capacity into the Waterloo Business Park and to allow for future large capacity tie feeders, between Moffet St ZS and the neighbouring ZS's, the 11kV distribution around the ZS will be reinforced. This will be achieved by creating a new feeder and extending and upgrading the capacity of existing feeders.	This project aligns with Orion's urban 11kV architecture standard, see NW70.60.06 for more details	697	FY20	Customers Safe, Reliable, Resilient System	Yes
536	Heathcote to Lyttelton 11kV reinforcement	To enable the establishment of the protection signalling as part of the Lyttelton tunnel 11kV cable project (Project 50), a communication cable is required to be laid from the Lyttelton tunnel entrance to Heathcote ZS. The aging overhead assets, spanning the same route, supplying Lyttelton are also due for replacement so these will be cabled in conjunction with the communications work.	Install two new 11kV cables out of Heathcote ZS to join the existing underground Lyttelton cable circuits on Martindales Rd in a common trench with a communication cable duct	The parallel 11kV spur overhead circuit will be also undergrounded as part of this project	1,200	FY20	Customers Safe, Reliable, Resilient System	Yes
936	Terrace Rd 11kV overhead reinforcement	Bankside ZS and Te Pirita ZS are neighbouring substations with single transformers that support each other during contingency events. During a transformer or subtransmission fault the interconnecting 11kV network is used to back-feed customers. However, the 11kV backup tie capability is limited by the conductor on Terrace Rd, which overloads and causes excessive voltage drop during contingency events.	The existing 7/14 Cu overhead 11kV line down Terrace Rd will be reconductored to Dog ACSR		359	FY20	Safe, Reliable, Resilient System	Yes

Table 6.6.5 HV minor project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
932	Pound Rd 11kV line reinforcement	The Moffett St ZS CB114 O/H feeder on Pound Rd is operating at 90% capacity at peak load times due to the large loads on Old West Coast Rd and West Coast Rd.	Replace the 19/16 Cu 11kV line with new Dog ASCR conductor on Pound Rd up to the Buchanans Rd corner and reconfigure the open points to minimise the voltage drop.	An alternative was to reuse the ex ISL 2102 - HAR 234 33kV overbuilt line to create a split 11kV feeder. This solution would have required a section of cable to be installed and key replacement of poles, cross-arms and insulators pushing the cost above the proposed solution. Long term this alternative would also require greater maintenance due to having twice as many cross-arms, insulators and conductors	92	FY20	Customers Safe, Reliable, Resilient System	Yes
933	Lancaster ZS to Milton ZS 11kV tie	The transfer capacity during an N-2 event between Milton ZS and Lancaster ZS is limited due to the low number of large capacity interconnecting 11kV tie feeders	Two large capacity cables were laid out of Lancaster ZS into the Waltham area in FY12 to establish additional 11kV tie capacity to Milton ZS with only one of the cables fully utilised as part of that works. This project makes use of the second cable to establish an additional large capacity tie between Lancaster ZS and Milton ZS.	This project aligns with Orion's urban 11kV architecture standard, see NW70.60.06 for more details	274	FY20	Safe, Reliable, Resilient System	Yes

Table 6.6.5 HV minor project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
922	Milton ZS 11kV alteration	Milton ZS was originally built as a four section closed-ring configuration. In 2012 all the 11kV panel switchgear were replaced with a new four section straight bus design. Upon commissioning it was found that this design did 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.	This project allows for the installation of a cabled wrap-around bus tie, including the bus coupler and link truck panel.	The requirement for this project is dependant on the outcome of the project where the busbars in the two outer sections are being uprated to 2500A to match the two inner buses in FY19 .	366	FY21	Safe, Reliable, Resilient System	Yes
952	Addington 11kV reinforcement	Addington ZS and Milton ZS are neighbouring substations that support each other during major contingency events using large capacity 11kV ties. One of the ties is currently limited in transfer capacity by an undersized cable section.	This project releases the 11kV tie capacity potential between Addington ZS CB19 and Milton ZS CB17 by reinforcing the feeder.	An opportunity to rationalise the 11kV switchgear in one of the affected 11kV distribution substation buildings is included as part of the works. This project aligns with Orion's urban 11kV architecture standard, see NW70.60.06 for more details	249	FY21	Safe, Reliable, Resilient System	Yes
663	Darfield township reinforcement	"Growth at Darfield township is expected to reach the 4MVA threshold for security of supply class D2, which requires restoration in 4 hours after a transformer outage. The switching plan requires 17 operations and while most of them are around the township, meeting the time requirement would be challenging given the distance from the Orion base."	An 11kV cable will be laid from the Kimberley ZS down West Coast Rd to Darfield township. This will carry the entire township load in the event of a Darfield ZS outage or dual 11kV feeder fault. Support for Kimberley ZS from Darfield ZS is also improved.	Alternative back-feed points for Darfield township (Hororata ZS, Highfield ZS and Greendale ZS) are too far away to provide adequate backup.	595	FY21	Customers Safe, Reliable, Resilient System	TBC

Table 6.6.5 HV minor project details

No.	Project	Issue	Chosen solution	Remarks/alternatives	Budget $,000	Year	AM focus areas	Business case (yes/no)
920	Southfield Drive Cable upgrade	Subdivision developments in Lincoln are progressing between Lincoln and Springston zone substations. End-to-end 11kV feeders are needed to provide security of supply and load shifting between the substations	This project upgrades existing small cables to provide a strong 11kV tie feeder between Lincoln and Springston zone substations.	This project requires the least work to provide the 11kV tie where the capacity is needed.	371	FY21	Safe, Reliable, Resilient System	TBC
913	Heathcote Lyttelton reconfiguration	Load in Lyttelton township and the Lyttelton Port is expected to increase due to plans outlined in the Christchurch City Council development plan and Lyttelton Port Recovery Plan 2015. A new 11kV cable through the Lyttelton tunnel is planned to improve both capacity and reliability to Lyttelton township (Project 50).	This project provides 11kV switchgear to connect the new cable into the existing network in Heathcote Valley and provide an increase in capacity and resiliency.	This project installs equipment on an existing Orion site and is the most cost effective solution to make use of the full capacity of the new 11kV through the tunnel.	232	FY21	Customers Safe, Reliable, Resilient System	TBC

6.6 Network development proposals continued

6.6.8 LV projects

Table 6.6.6 is an overview of 400V project costs planned for the next 10 years. Low voltage network monitoring and reinforcement forms part of our staged approach to new technologies. More information about the impact of emerging technologies on our LV network is provided in Section 6.2 In particular see Section 6.2.2.1 for a description of LV monitoring.

LV reinforcement projects will included consideration of non-traditional solutions such as static synchronous compensators (STATCOMs) or network batteries to provide reactive voltage support

Table 6.6.6 LV projects – $000

No.	Project	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
884	Low voltage network monitoring	554	543	798	782	1,022	1,002	1,227	1,203	1,414	1,386
Unidentified network reinforcement		0	250	250	300	300	300	350	350	350	350
LV projects totals		**554**	**793**	**1,048**	**1,082**	**1,322**	**1,302**	**1,577**	**1,553**	**1,764**	**1,736**

6.6.9 Network connections and extensions

The network connections and extensions budget includes household and business connections. Forecast connection numbers are outlined in Section 6.3.4.4. Business connections are becoming more expensive as different layouts are introduced to further enhance worker safety. Costs are also being driven up by implementing the National Code of Practice for Utility Operators' Access to Transport Corridors to its full extent.

Table 6.6.7 Connections / extensions capex – expenditure forecast – $000

Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
General connections	3,705	3,693	3,699	3,693	3,332	3,332	3,332	3,332	3,332	3,332	**34,781**
Large connections	1,258	1,252	1,252	1,252	1,130	1,130	1,130	1,130	1,130	1,130	**11,794**
Subdivisions	3,429	3,414	3,418	3,414	3,080	3,080	3,080	3,080	3,080	3,080	**32,155**
Switchgear purchases	1,297	1,298	1,297	1,242	1,242	1,297	1,242	1,242	1,242	1,242	**12,639**
Transformer purchases	2,189	2,193	2,190	1,971	1,971	1,971	1,971	1,971	1,971	1,971	**20,370**
Total	**11,877**	**11,849**	**11,856**	**11,572**	**10,755**	**10,810**	**10,755**	**10,755**	**10,755**	**10,755**	**111,739**

6.7 Value of Customer Demand Management alternatives

Customer Demand Management initiatives can provide alternatives to investment in traditional network development solutions. This section is included in our AMP to assist potential Customer Demand Management providers to determine the approximate funding available from Orion when specific projects are deferred through Customer Demand Management.

Table 6.7.1 is a high level assessment of the annual per kW cost of proposed network solutions where Customer Demand Management could be used to defer the project. If a Customer Demand Management solution is presented, further detailed analysis is undertaken to compare options.

For example:

Halswell zone substation transformer scheduled for FY26 has a capital cost of $2.4M and an annual capital funding cost of $290k. It provides capacity for 850kW of load growth per annum. For a Customer Demand Management solution to be economic and provide a one year deferral of a network solution, the cost per kW must be lower than $340/kW ($290k /850kW). If the Customer Demand Management solution can provide three years of deferral (2.5MW at peak) then the Customer Demand Management proposal cost must be lower than:

- $340/kW for 850kW in the first year
- $170/kW for 1.7MW in the second year
- $110/kW for 2.5MW in the third year

The values in the following table assume that the Customer Demand Management solution is provided in the year required and therefore discounted values apply for Customer Demand Management solutions implemented earlier than required.

Table 6.7.1 Customer Demand Management value for network development alternatives

No.	Project description	Year	Budget capital ($,000)	Growth per year (kW)	$ per kW available for CDM alternative		
					Year 1	Year 2	Year 3
894	Springston ZS 2nd 66/11kV transformer	FY24	1,660	500	400	200	130
666	Porters Village	FY25	4,600	4,400	130	70	40
919	Halswell ZS 3rd transformer	FY26	2,399	850	340	170	110

Customer Demand Management initiatives can provide alternatives to investment in traditional network development solutions.

7 Managing our assets

Photo: One of 216 11kV substations in our network, our sturdy substation in Linwood Avenue has been serving customers since 1934.

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.

Over the past two to three decades 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 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 which means our customers benefit during adverse events through the quality and timeliness of emergency repairs.

Replacement programmes for our poles, switchgear and cable 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, see Figure 4.7.2. We reduce the impact of these events by conducting regular proactive programmes where approximately 70 per cent of our 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 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 heath, 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 11,600 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 11,600 buildings, substations, kiosks and land assets that form an integral part of Orion's distribution network. Our network and distribution substation buildings vary in both construction and age. Orion owns approximately 80% of its network substation buildings and approximately 30% of its distribution buildings. Around 150 of our substations are incorporated in a larger building we do not own, often customer owned premises.

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. Our Region A zone substations date back to as early as 1962, and our most recently built was Waimakariri, commissioned in 2016.

Orion has 49 zone substations (Table 7.3.1) and in general, they 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. A zone substation schedule is shown in Table 7.3.2.

Table 7.3.1 Zone substation description and quantity

Voltage	Quantity	Description
66kV / 11kV	26	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. 8 in Region B are supplied by overhead lines (Brookside, Dunsandel, 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	18	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, Little River and Highfield 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	**49**	

Table 7.3.2 Zone substation equipment schedule

Zone substation	Circuit breakers			Power transformers				Zone substation	Circuit breakers			Power transformers			
	66kV	33kV	11kV	66/33kV	66/11kV	33/11kV	Rating (MVA)		66kV	33kV	11kV	66/33kV	66/11kV	33/11kV	Rating (MVA)
Addington	13		33		4		20/30 x2 and 30/36 x2	Islington		14					
Annat	1		4			1	7.5	Kimberley	3		13		2		11.5/23
Armagh	5		33		2		20/40	Lancaster	5		22		2		34/40
Bankside	1		5			1	7.5/10	Larcomb	3		10		2		11.5/23
Barnett Park			12		1		11.5/23	Lincoln		3	9			2	7.5/10
Bromley	11		25		3		30/36	Little River		3	3			1	2.5
Brookside	3	1	10		1		7.5/10	McFaddens	5		24		2		20/40
Dallington	3		25		2		20/40	Middleton	2		19		2		20/40
Darfield		2	6			1	7.5/10	Milton			23		2		20/40
Diamond Harbour		3	4			1	7.5	Moffett St		1	14			2	11.5/23
Dunsandel	4		11		2		7.5/10 and 11.5/23	Motukarara		6	6			2	7.5
Duvauchelle		5	9			2	7.5	Oxford-Tuam			23		2		20/40
Fendalton			20		2		20/40	Pages Kearneys			16				
Greendale	1		6		1		7.5/10	Papanui	9		34		2		20/40
Grimseys Winters			18					Portman			18				
Halswell	8		11		2		11.5/23	Prebbleton		2	8			2	11.5/23
Harewood		2	9			2	7.5	Rawhiti	3		15		2		20/40
Hawthornden			28		4		20/40 x2 and 11.5/23 x2	Rolleston		2	9			2	7.5/10
Heathcote	8		24		2		20/40	Shands Rd		4	12			2	11.5/23
Highfield	1		6			1	7.5	Sockburn			18			3	10/20 x2 and 11.5/23 x1
Hills Rd		1	4			1	7.5	Springston	8	12	9	2	1		11.5/23 and 30/60 x2
Hoon Hay			25		2		20/40	Te Pirita	1		6		1		7.5/10
Hornby		10	11			2	10/20	Waimakariri	4		18		2		20/40
Hororata		9	5			1	7.5	Weedons	6		11		2		11.5/23
Ilam			13												
Killinchy	3		6		1		7.5/10	**Totals**	**109**	**63**	**724**	**3**	**51**	**31**	

7.3.2.2 Network substation

There are 216 network substations in our 11kV network, all within Region A. They contain at least one 11kV circuit breaker per connected primary cable and one or more circuit breakers for radial distribution feeders. Some also contain secondary 11kV switchgear, one or more distribution transformers and 400V distribution panels.

Network substations have historically been installed whenever the load on radial feeders exceeded the design limit of cable capacity and when primary cables with adequate spare capacity were available nearby. The original approach was that no radial secondary loads were to be supplied from zone substations and all such loads were to be supplied from network substations. In recent years this approach has been modified so that if suitable spare switchgear is available at a zone substation, and it is more economical to do so, secondary cables may be laid from the zone substation to reinforce overloaded cables. This avoids the need for additional network substations.

Due to changes in the location of load during their lifetime, network substations may become under-utilised. In these cases, and when it is economical to do so, the primary cables supplying the substation may be through-jointed and the secondary load transferred to other feeders and the network substation decommissioned.

7.3.2.3 Distribution substation

We have 11,489 distribution substations of a variety of types. They take supply at 11kV from either a zone substation, a network substation or from another distribution substation. Of those where our equipment is housed in buildings, many are in buildings owned by our customer. The different types of distribution substation are shown in Table 7.3.3.

Table 7.3.3 Distribution substation type

Type	Quantity	Description
Building	251	These are similar to network substations in most aspects except for their status in the network. 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	3,077	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. See Table 7.4 for kiosk types
Outdoor	775	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	6,416	Single pole mounted substations usually with 11kV fusing and a transformer
Pad transformer	809	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	161	Cabinets that contain only switchgear
Totals	**11,489**	

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 network 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 need 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.

Prior to the Canterbury earthquakes in 2010 and 2011 we undertook a 15 year programme to seismically strengthen our zone and network substation buildings.

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

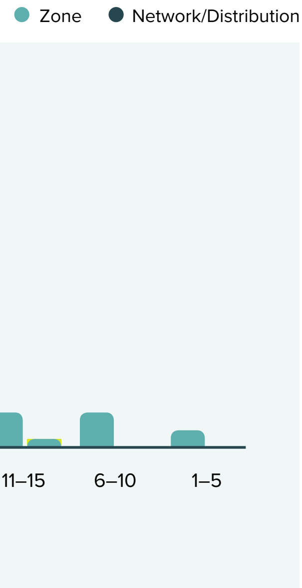
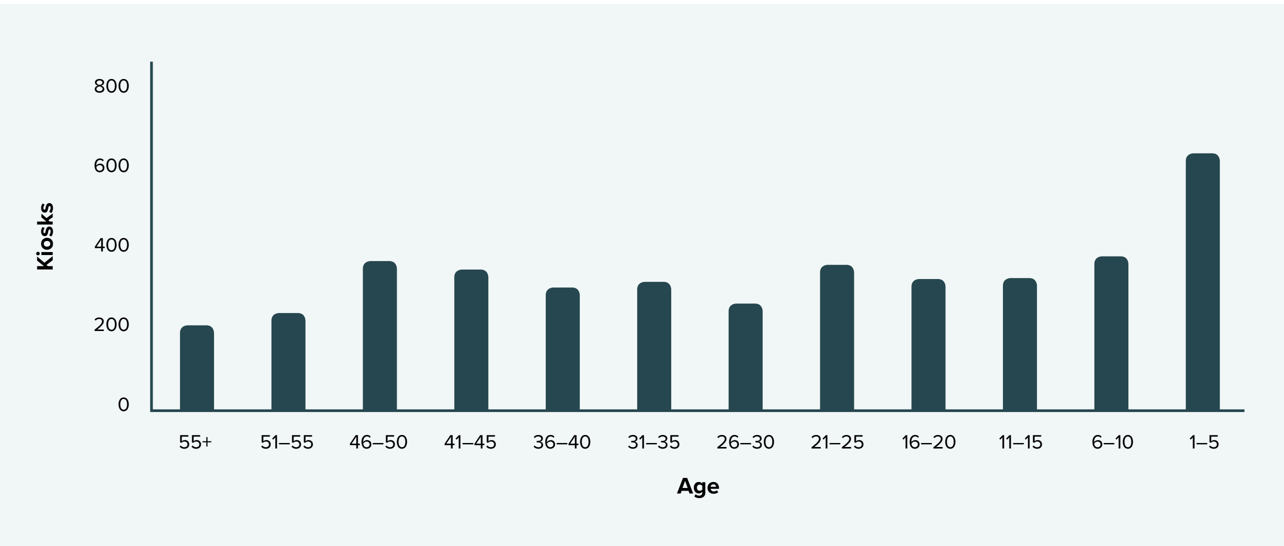


Figure 7.3.2 Kiosk age profile



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 7.3.4 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 and resilient system as set out in our asset management objectives in Section 2.8.

Table 7.3.4 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	A programme to run over a 10 year period to upgrade security and safety is underway. This mainly involves 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
	Vegetation in and around our assets poses an operational safety hazard	We conduct planned and reactionary grounds maintenance programmes
	Illegal 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 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

Our forecast operational expenditure (Table 7.3.6) is in the Commerce Commission categories. The substation monitoring and inspection programmes are listed in Table 7.3.5.

Table 7.3.5 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
Network substations	A complete visual component inspection and the reading of any transformer loading Maximum Demand Indicators (MDIs)	6 months
Network substation grounds maintenance	These sites are generally of larger land area than the other network substation sites. Grounds are adequately maintained, vegetation is kept under control 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 have recently engaged local media outlets to highlight the reporting procedure for graffiti on our assets. 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	Under development

Table 7.3.6 Network property operational expenditure (real) – $000											
	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	75	75	75	75	75	75	75	75	75	75	750
Routine and corrective maintenance and inspections	2,200	2,200	2,200	2,140	2,140	2,080	2,030	2,030	2,030	2,030	21,080
Asset replacement and renewal	135	135	135	135	135	235	235	235	235	235	1,850
Total	2,410	2,410	2,410	2,350	2,350	2,390	2,340	2,340	2,340	2,340	23,680

7.3.5 Replacement plan

The forecast capital expenditure in Table 7.3.7 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
- Seismically strengthen substations built within customer buildings
- Replace all fibreglass kiosks as well as some steel kiosks due to rust. A number of the steel kiosks are located near the coast

Table 7.3.7 Network property replacement capital expenditure (real) – $000											
	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Zone substations	430	130	130	130	130	130	130	130	130	130	1,600
Distribution substations and transformers	545	545	545	545	545	545	545	545	545	545	5,450
Other network assets	435	335	335	335	335	335	335	335	335	335	3,450
Total	1,410	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	1,010	10,500

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 7.3.8.

A new opex programme has been identified to better forecast the costs associated with decommissioning our substations. These works are mostly driven by our changing customer needs.

Table 7.3.8 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 520 kilometers of lines spanning over 396 towers and 5,797 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. We will continue with our tower and pole asset management practices to maintain our very low failure rate level for this asset class.

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 5. 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.

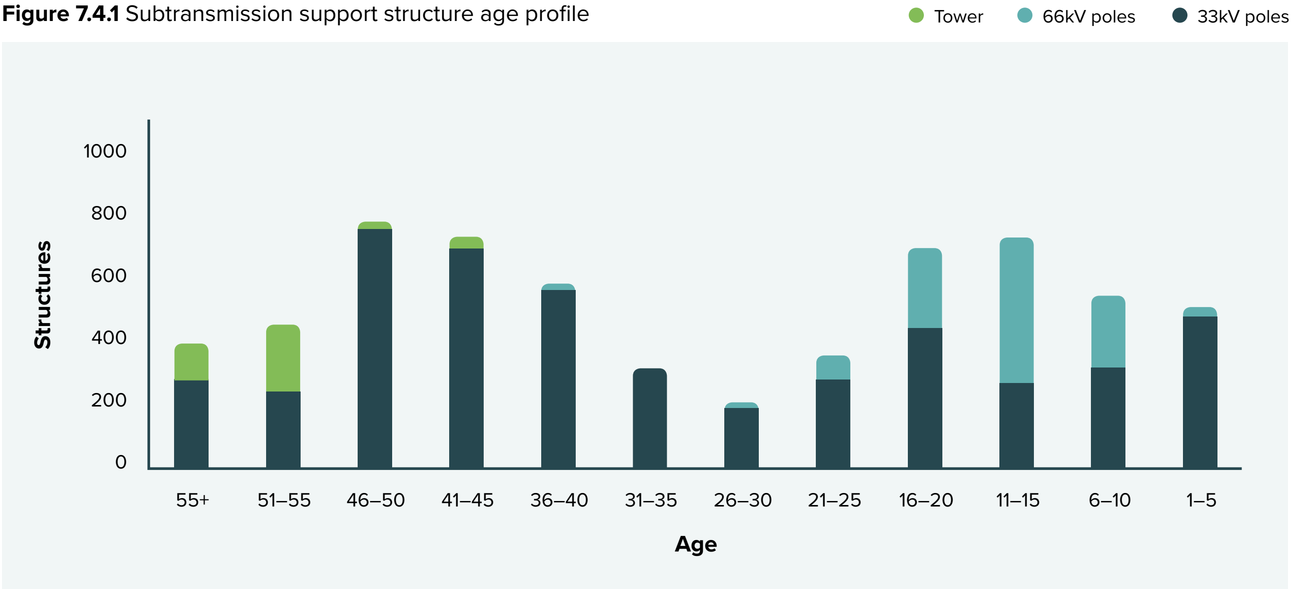
The age profile is shown in Figure 7.4.1. More than 95% of our 66kV poles are less than 20 years old and are well within their life expectancy. We have a large number of 33kV poles. The life expectancy of these poles is 40 to 45 years for wooden poles, and 80 years for concrete poles. Improved treatment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

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	Nominal asset life	% of population	Quantity	Nominal asset life	% of population	Total
Hardwood pole	998	45	68%	2,184	45	46%	
Softwood pole	35	40	2%	547	40	12%	
Concrete pole	25	80	2%	1,991	80	42%	
Steel pole	15	60	1%	2	60		
Steel tower	396	70-80	27%				
Total	**1,469**			**4,724**			**6,193**

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.

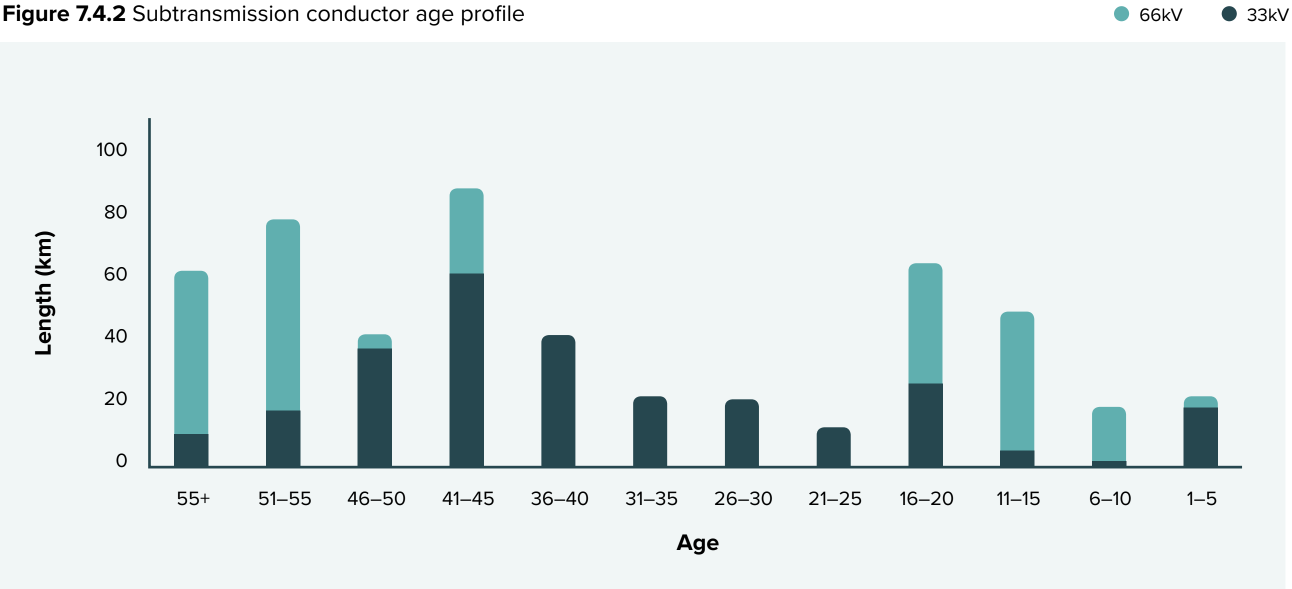
Conductors

Conductor types on our 33kV and 66kV overhead lines consist of hard drawn copper (HD) and aluminium conductor steel reinforced (ACSR). We no longer install copper conductors, except for minor repairs. 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)	Nominal asset life	% of population	Length (km)	Nominal asset life	% of population	Total
ACSR	244	60	100%	229	60	83%	
Copper				47	60	17%	
Total	**244**			**276**			**520**

Figure 7.4.2 Subtransmission conductor age profile



7.4.3 Asset health

7.4.3.1 Condition

Towers

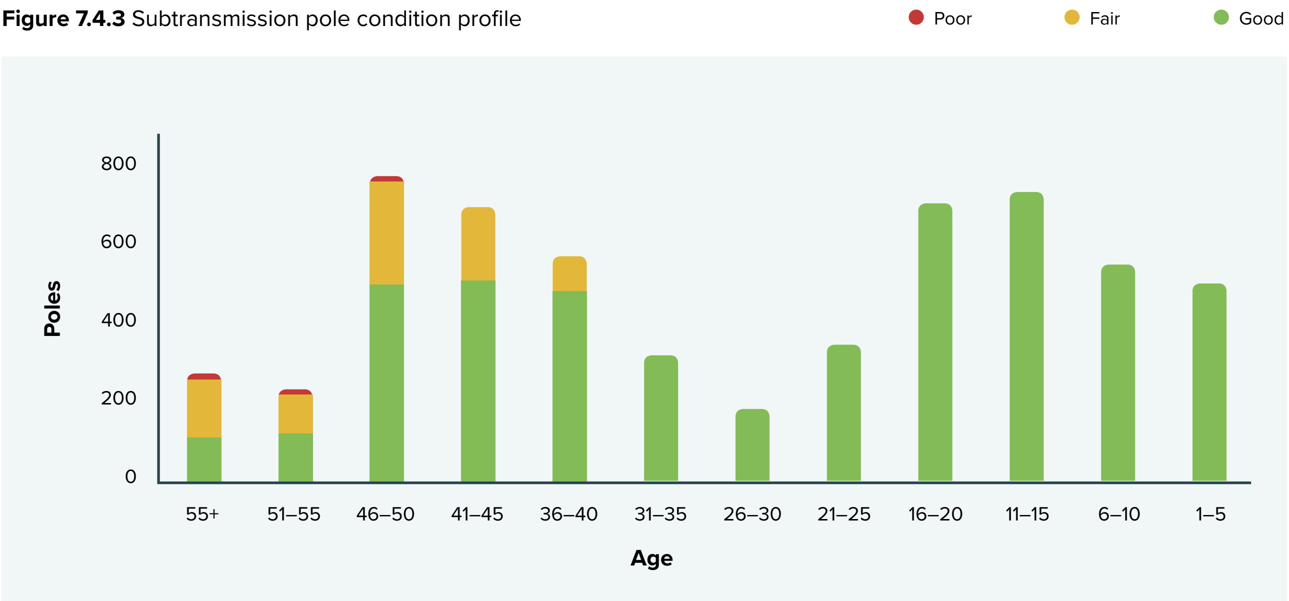
The overall condition of our steel towers is good. The ex-Transpower towers between Addington and Islington came with no additional paint protection which we are addressing with our painting programme. The condition of most tower grillage foundations below ground level is good. A few are in fair condition 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. Most 66kV poles are less than 20 years old and therefore are in good condition. Most of the 33kV poles are also in good condition. 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

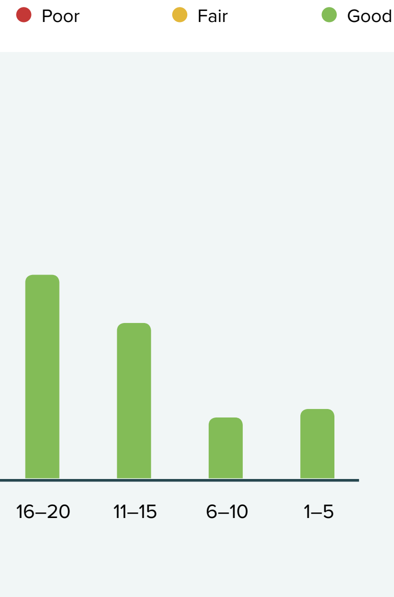


Conductor

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

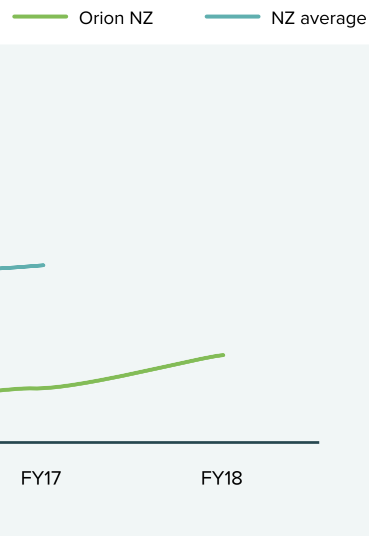


7.4.3.2 Reliability

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 three years.

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

Figure 7.4.5 Subtransmission line faults per 100km



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.

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.

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.

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 notify tree owners if their trees might become a hazard 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 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 10 years (retighten/ refurbishment)

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	125	125	125	125	125	125	125	125	125	125	**1,250**
Routine and corrective maintenance and inspections	1,640	1,640	1,665	1,640	1,640	1,640	1,640	1,640	1,640	1,665	**16,450**
Asset replacement and renewal	345	255	255	255	255	255	255	255	255	255	**2,640**
Total	**2,110**	**2,020**	**2,045**	**2,020**	**2,020**	**2,020**	**2,020**	**2,020**	**2,020**	**2,045**	**20,340**

7.4.5 Replacement plan

Towers

Currently we have not seen any evidence to suggest any of our towers require replacement.

Poles

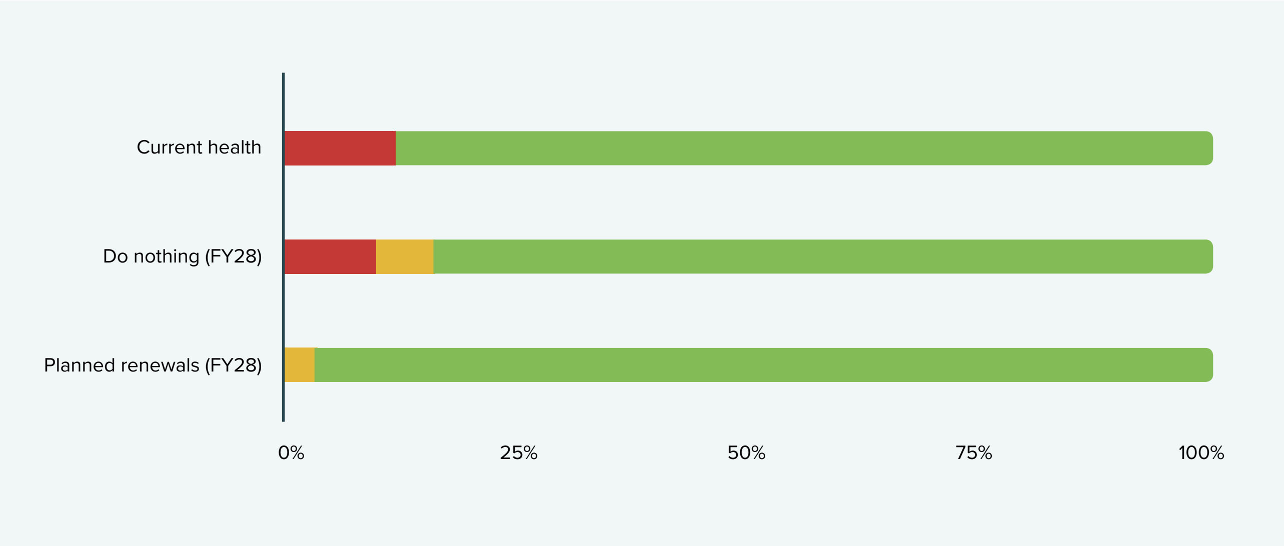
We use CBRM to help determine the replacement requirements for our subtransmission poles. We are planning to replace 7% of our subtransmission pole population over the next five years. This is based on a combination of our risk based approach to replacement and our visual inspection programme. We have 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 'Planned renewals'.

'Do nothing' involves regular maintenance only, but does not prevent material deterioration in condition. 'Planned renewals', our chosen solution, identifies and prioritises poles based on condition and criticality.

We plan to continue replacing our 33kV poles at a steady rate as supported by CBRM. 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 7.4.6.

We are planning to replace 7% of our subtransmission pole population over the next five years.

Figure 7.4.6 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 will soon need to replace the conductor on our Bromley to Heathcote line. This was planned for FY20, however this has now been deferred while we assess our replacement options, as a result the budget has been moved to FY25. In the meantime, we will retest the conductor in FY22 to monitor deterioration. Further out in FY27 we also have a placeholder replacement budget for some conductor 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

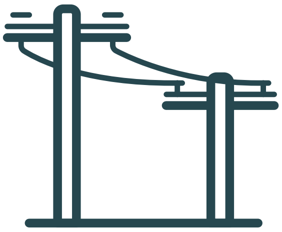
	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Overhead lines – Subtransmission	1,020	660	660	660	660	3,160	660	3,160	660	660	**11,960**
Total	**1,020**	**660**	**660**	**660**	**660**	**3,160**	**660**	**3,160**	**660**	**660**	**11,960**

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 are also continuing to work with the manufacturer of a non-destructive pole testing device. There is potential for this innovation to better detect hidden decay in wooden poles which could enhance our pole replacement programme for wooden poles of all voltage classes.



Our 11kV distribution overhead system has 3,189km 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, connecting the “last mile” of power to 32,000 customers. 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 3,189km of lines servicing the rural area of central Canterbury, Banks Peninsula and outer areas of Christchurch city. These lines are supported by 47,313 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.

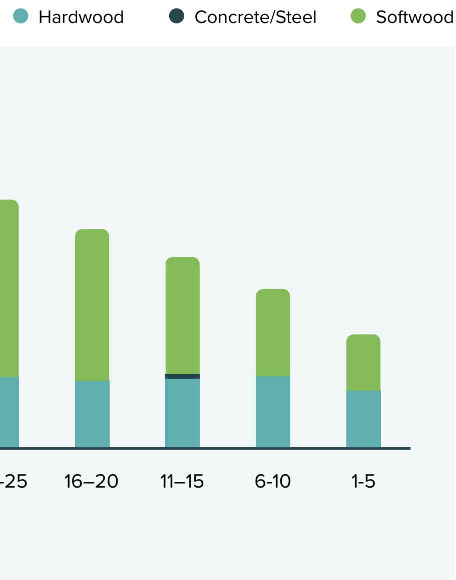
Table 7.5.1 11kV pole quantities by type

Pole type	Quantity	Nominal life	Population %
Timber (Hardwood)	13,848	45	29%
Timber (Softwood)	15,688	40	33%
Concrete	17,731	80	38%
Steel pole and piles	46	60	<1%
Total	**47,313**		

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. While these concrete poles are still within their typical service life there are a number of wooden poles that have exceeded their nominal life.

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 these component ages.

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

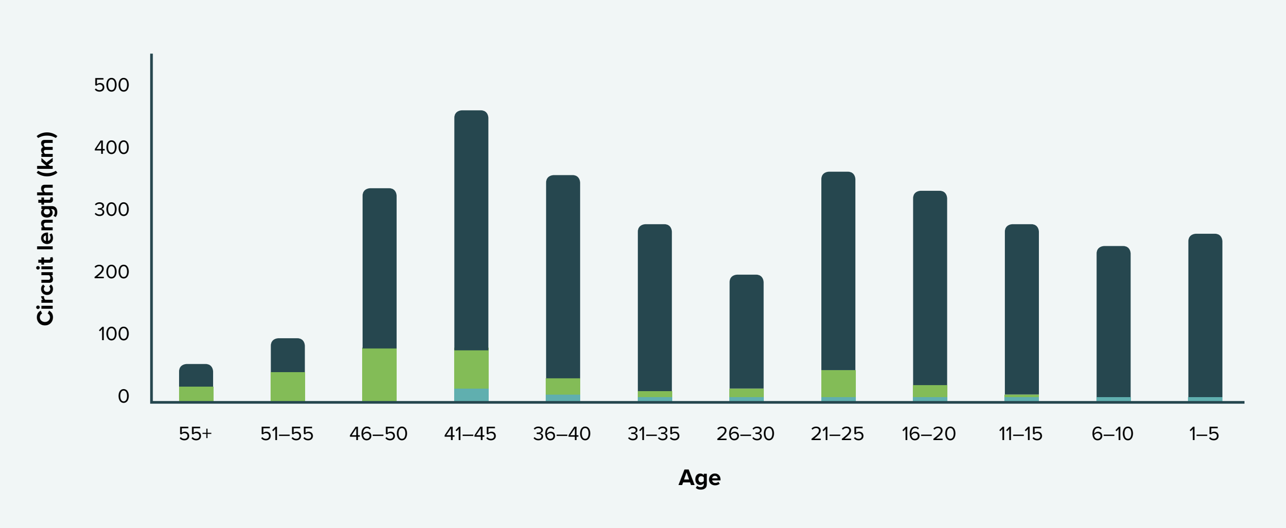
Table 7.5.2 11kV conductor quantities by type

Conductor type	Length (km)	Nominal asset life	% of population
Copper (Cu)	321	60	10%
Aluminium (ACSR)	2,799	60	88%
Other aluminium (AAC & AAAC)	69	60	2%
Total	**3,189**		

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

ACSR Copper AAC/AAAC



7.5.3 Asset Health

7.5.3.1 Condition

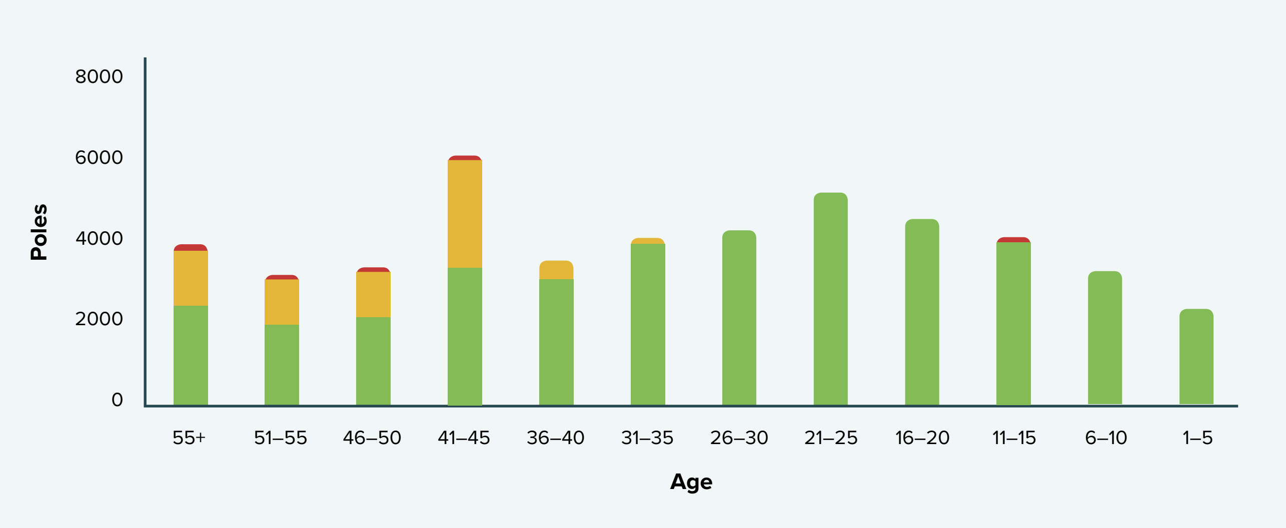
Poles

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.

Our replacement programme will prioritise poles in fair and poor condition, the majority of which were installed in the 1960s and 70s (age 46+).

Figure 7.5.3 11kV pole condition profile

Poor Fair Good



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 and moving to a range of smaller and older ACSR conductors. We are still developing our CBRM model for 11kV overhead conductors.

7.5.3.2 Reliability

SAIDI and SAIFI

The 11kV overhead asset class is the largest contributor to our regulatory SAIDI and SAIFI performance. Figure 7.5.4 shows the trend of our uncapped SAIDI and SAIFI performance for the 11kV overhead asset class. The extreme weather event in FY14 had a significant impact on our performance. We believe the current performance level is satisfactory.

Figure 7.5.4 Uncapped SAIDI and SAIFI for 11kV overhead

Overhead faults/100km

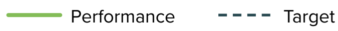
Figure 7.5.5 is compiled using information disclosure data. It shows that our distributions lines fault rate, on average, has been declining. Our target is to achieve less than 18 faults per 100km and this target will be reviewed annually. The biggest factors impacting the overhead reliability are:

- **Severe weather events –** the historical wind/snow storm events were few and far between. However, weather experts are predicting that extreme weather events will be occurring more often
- **Disabling auto-reclosers (A/R) –** during windy days, there are often intermittent faults such as wind swept vegetation touching the lines. The A/R can quickly restore supply after these transient faults. However, in order to reduce the risk of fires, during the period when fire bans are in place, a procedure of disabling the auto-reclosers was introduced. Disabling this auto-reclose function has led to more 'unknown' faults
- **Asset lifecycle –** Some insulators are coming to the end of their useful life and are impacting on reliability

Recently we have been focusing on reliability improvement for Region B townships by targeting feeders through a combination of insulators and crossarm replacements and installation of automated line switches.

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.

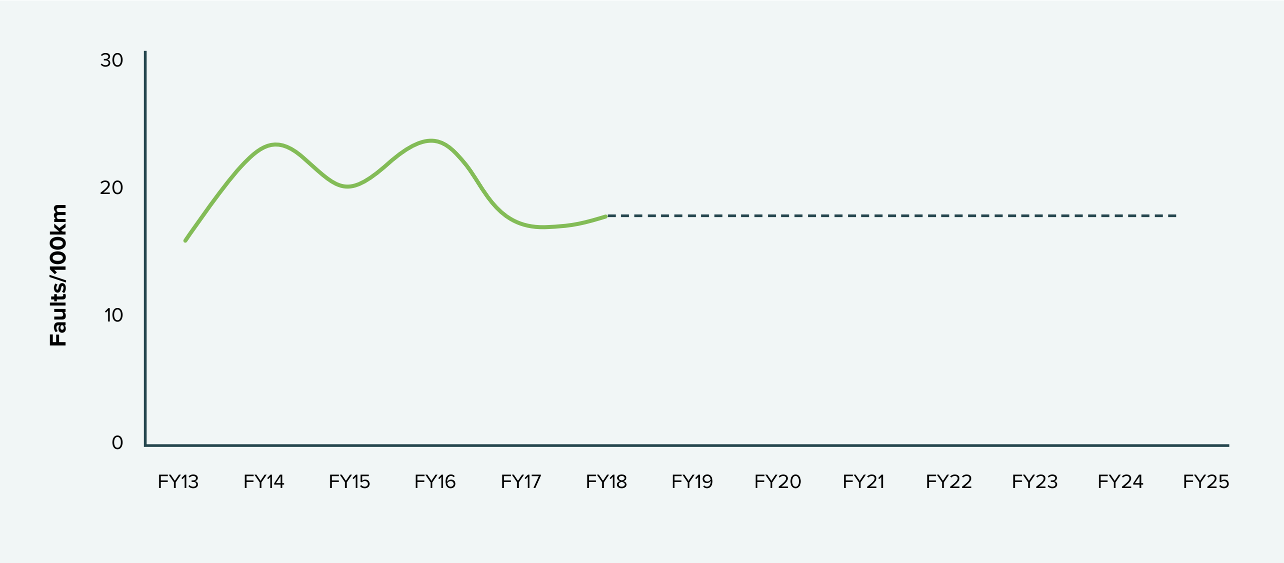
Figure 7.5.5 11kV line faults per 100km



Pole failure rate

To support public safety and network reliability we have established a pole failure rate[1] target of less than 1 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, two years of comparable data has been reviewed under this benchmark with Figure 7.5.6 showing that we met the asset class objective in FY18.

Figure 7.5.6 Pole failure rate (all voltage classes)



[1] "Pole Failure" is where the pole has failed to be self-supporting under normal load conditions and has fallen or is sufficiently unstable that it is posing a risk to people's safety or damage to property. The term does not cover events where a pole has fallen due to an "Assisted Failure", such as impacts from vehicles or trees. It also does not cover "red tag" poles that are replaced immediately when found to be at risk of failure under normal structural loads. We have monitored our poles according to this definition since 2016.

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	Visual inspection of poles and lines	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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	**22,150**
Vegetation management	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	**30,500**
Routine and corrective maintenance and inspections	870	870	515	515	915	915	915	515	515	915	**7,460**
Asset replacement and renewal	935	935	935	935	935	935	935	935	935	935	**9,350**
Total	**7,070**	**7,070**	**6,715**	**6,715**	**7,115**	**7,115**	**7,115**	**6,715**	**6,715**	**7,115**	**69,460**

7.5.5 Replacement plan

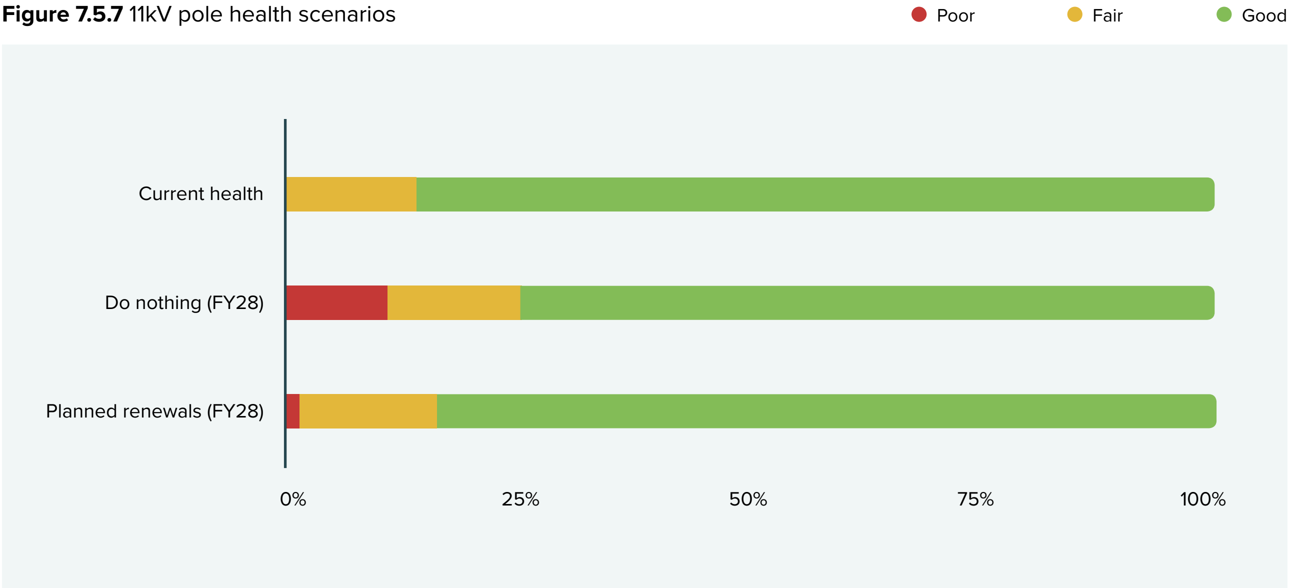
Poles

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 1 in 10,000 poles and to reduce our faults per km rate we have considered these options:

- **CBRM optimised replacement –** 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

Using our CBRM model we are able to project the current and future asset health of the 'do nothing' versus the CBRM optimised replacement approach options as shown in Figure 7.5.7.

Figure 7.5.7 11kV pole health scenarios

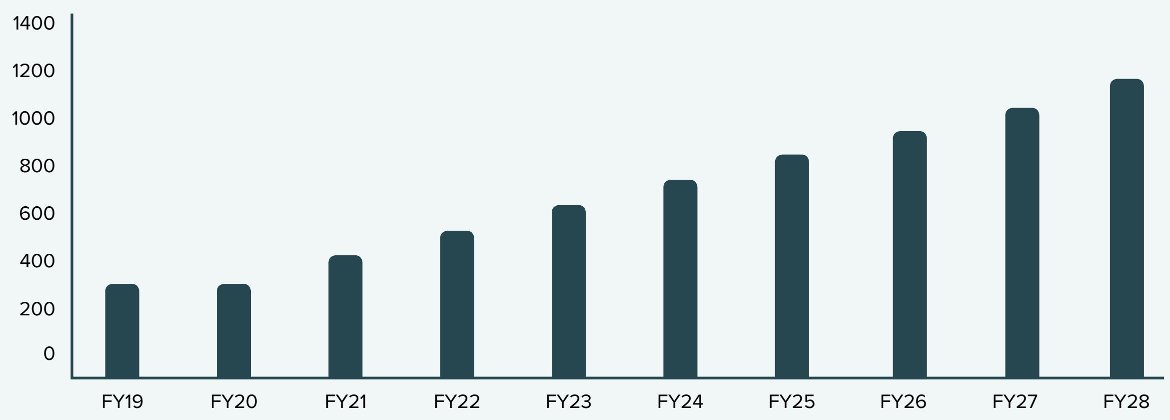


We believe our targeted replacement plan is appropriate as it achieves our asset class objective to maintain a safe, reliable, resilient system. While the condition profile in FY28 shows some poles as red or poor health the overall risk profile remains largely the same. This also aligns with our health and safety focus to achieve no serious safety event involving employees, service providers or the public.

This replacement programme, in conjunction with subtransmission and LV pole replacement supports our asset class objective to maintain less than 1 in 10,000 failure.

As a result we are planning a steady increase in replacement of our mainly wooden poles. This equates to replacing approximately 3% of our 11kV poles over the next five years. This steady increase is necessary to allow time for our service providers to resource appropriately for the work programme.

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. Conductor replacement is currently forecast at approximately 60km in FY20 then 40km over the following four years.

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 for approximately 4km of conversion to underground of some overhead lines in the western suburbs of Christchurch. The drivers for this replacement are a mixture of condition based replacement, safety, resilience and reliability improvement. A business case including cost benefit analysis is still to be completed to assess the viability of this project.

The capex expenditure forecast is expected to contribute to improving our asset class reliability performance while maintaining our pole failure rate to less than 1 failure per 10,000 poles.

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 1 failure per 10,000 poles.

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Distribution & LV Lines	2,685	2,150	2,765	4,615	4,615	5,850	5,850	7,850	7,945	7,945	**52,270**
Distribution switchgear	590	590	590	590	590	590	590	590	590	590	**5,900**
Total	**3,275**	**2,740**	**3,355**	**5,205**	**5,205**	**6,440**	**6,440**	**8,440**	**8,535**	**8,535**	**58,170**

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 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.

Our low voltage 400V distribution overhead system is 2,689km 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 2,689km of lines mainly within Region A, delivering power from the street to customer's premises. This includes 912km of streetlighting lines. The lines are supported by wooden and concrete poles. The Region A 400V network is a multiple earthed neutral system operating at 400V between phases and 230V to earth. In the city the network can be interconnected with adjacent substations by installing ties at various normally open points. To counteract our aging pole population and maintain our performance we are increasing the pole replacement rate over the AMP period.

7.6.2 Asset description

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

Poles

We own approximately 36,000 poles with a top voltage of 400V. There are also approximately 15,000 poles owned by Chorus that support our LV pole top hardware and conductors. Three types of poles are used: 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.

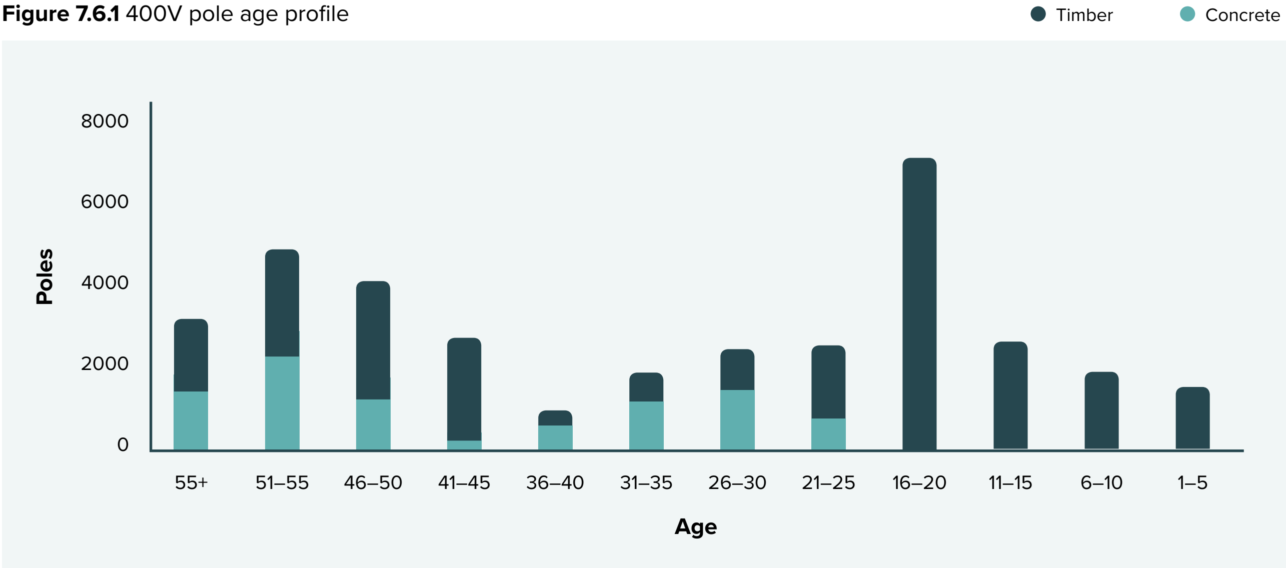
Table 7.6.1 400V pole quantities by type

Pole type	Quantity	Nominal asset life	% of population
Timber (hardwood)	12,279	45	34%
Timber (softwood)	14,506	40	40%
Concrete	9,348	80	26%
Total	**36,133**		

7.6 Overhead lines – distribution 400V continued

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



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

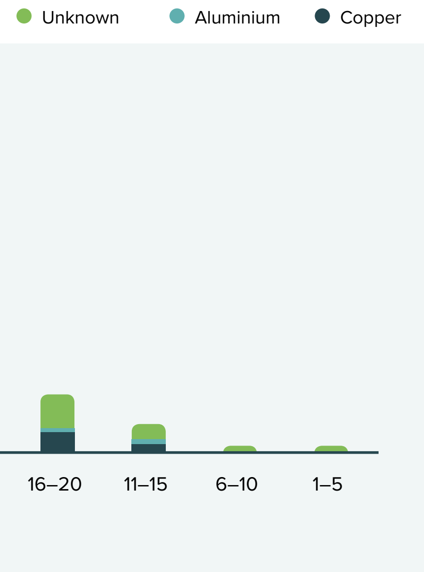
We use a variety of mainly covered conductor types for the LV overhead network. The conductor type chosen is influenced by economic considerations, asset location, environmental and performance factors. The different conductor categories are listed in Table 7.6.2.

Table 7.6.2 400V conductor quantities by type

Conductor type	Length (km)	Nominal asset life	% of population
Copper (Cu)	795	60	30%
Aluminium (Al)	148	60	6%
Unknown	834	60	31%
Streetlighting (Cu)	912	60	33%
Total	**2,689**		

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



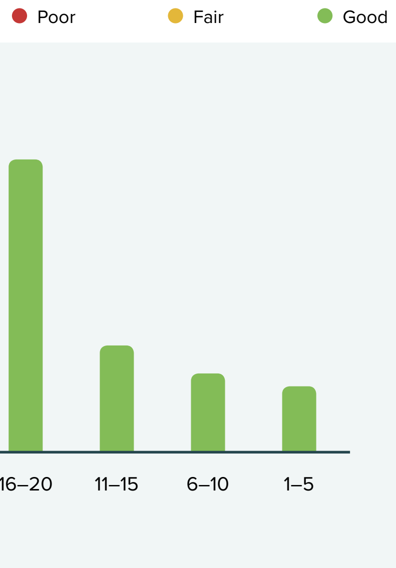
7.6.3 Asset health

7.6.3.1 Condition

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. Our replacement programme will prioritise poles in fair and poor condition, the majority of which were installed in the 60s and 70s (age 46+).

Our replacement programme will prioritise poles in fair and poor condition, the majority of which were installed in the 60s and 70s.

Figure 7.6.3 400V pole condition profile



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.

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. We have found equipment failure has increased over the last two years. This is due to more suspect poles being reported because of an increased awareness around our revised pole tagging procedures. We have also found that third party related incidents including car versus poles have decreased over the last four years.

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, as shown in Table 7.6.3, are driven by a combination of time based inspections and reliability centred maintenance.

Table 7.6.3 400V overhead maintenance plan

Maintenance activity	Strategy	Frequency
Pole inspection	Visual inspection of poles and line	5 years
Vegetation management	We have a proactive programme in place to trim trees within the corridor stated in the tree regulations. We also consult with land owners with trees that pose a risk to our assets, but are outside the trim corridor. Refer to Section 7.12 for more information	5 years
Retightening programme	Includes retightening of components, replacement of problematic assets	Initially at 12–18 months from new (retighten), then at 30 years intervals (retighten) Note: retighten only and no refurbishment unless the pole is replaced

An annual forecast of 400V overhead operational expenditure in the Commerce Commission categories is shown in Table 7.6.4.

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	**12,000**
Vegetation management	900	900	900	900	900	900	900	900	900	900	**9,000**
Routine and corrective maintenance and inspections	1,535	1,535	1,935	1,935	1,535	1,535	1,535	1,935	1,935	1,535	**16,950**
Total	**3,635**	**3,635**	**4,035**	**4,035**	**3,635**	**3,635**	**3,635**	**4,035**	**4,035**	**3,635**	**37,950**

7.6.5 Replacement plan

Poles

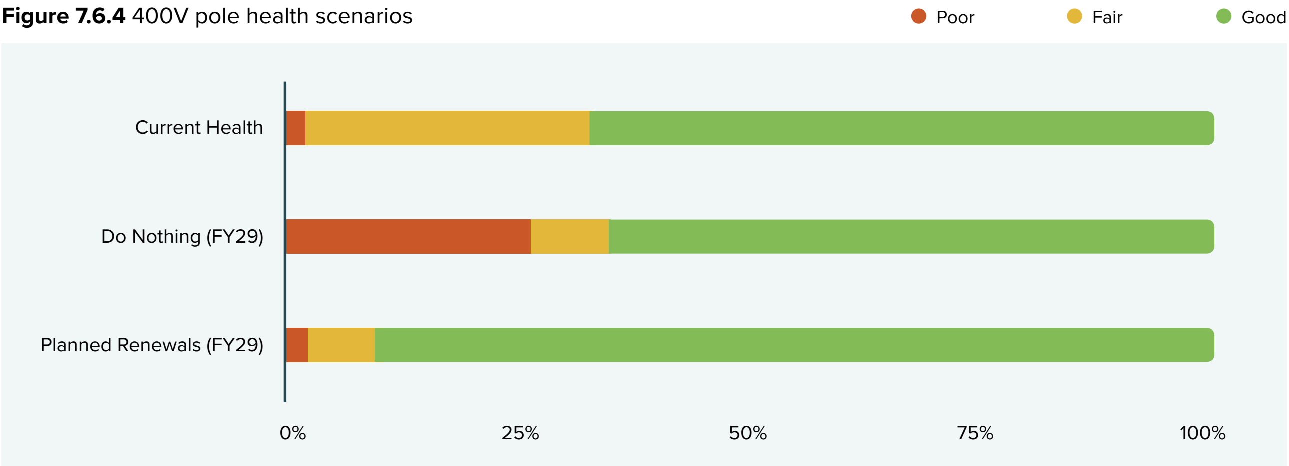
In recent times our replacement rate for LV poles has been moderately low. This was in part due to our large investment in the replacement of poles in 2000 and 2001 which brought the condition of our poles up to a very good level. The buffer that this created has now reduced. We plan to increase our replacement rate guided by CBRM to maintain the health of our LV poles.

To meet our asset class objective to maintain a pole failure rate of less than 1 in 10,000 poles and to reduce our faults per km rate we have considered these options:

- **CBRM optimised replacement –** 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

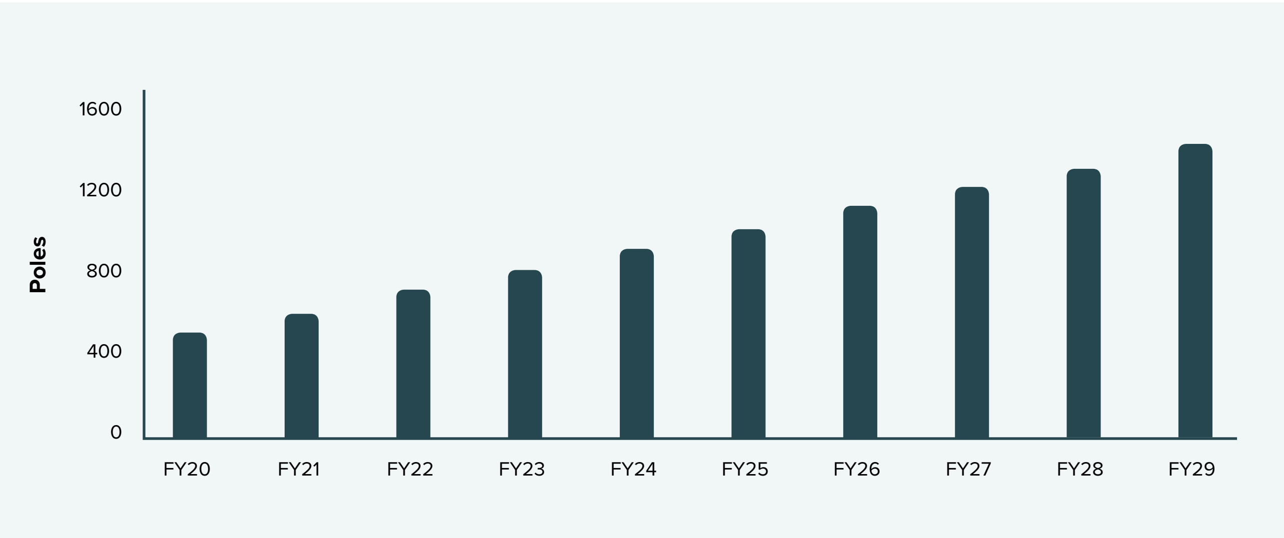
Using our CBRM model we are able to project the current and future asset health of the 'do nothing' versus the CBRM optimised replacement approach options as shown in Figure 7.6.4.

Figure 7.6.4 400V pole health scenarios



As a result we are planning a steady increase in replacement of our mainly wooden poles as shown in Figure 7.6.5. This equates to replacing approximately 26% of our LV poles over the 10 year period. This steady increase is necessary to allow time for our service providers to resource appropriately for the work programme.

Figure 7.6.5 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 or 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 7.6.5 shows the replacement expenditure in the Commerce Commission categories.

Table 7.6.5 400V overhead replacement capital expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Distribution & LV Lines	1,405	1,765	2,125	2,485	2,845	3,205	3,565	3,925	4,285	4,285	**29,890**
Other network assets	100	100	100	100	100	100	100	100	100	100	**1,000**
Total	**1,505**	**1,865**	**2,225**	**2,585**	**2,945**	**3,305**	**3,665**	**4,025**	**4,385**	**4,385**	**30,890**

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 129km 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 129km 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 both the 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

Figure 5.3.2 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 39km 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.

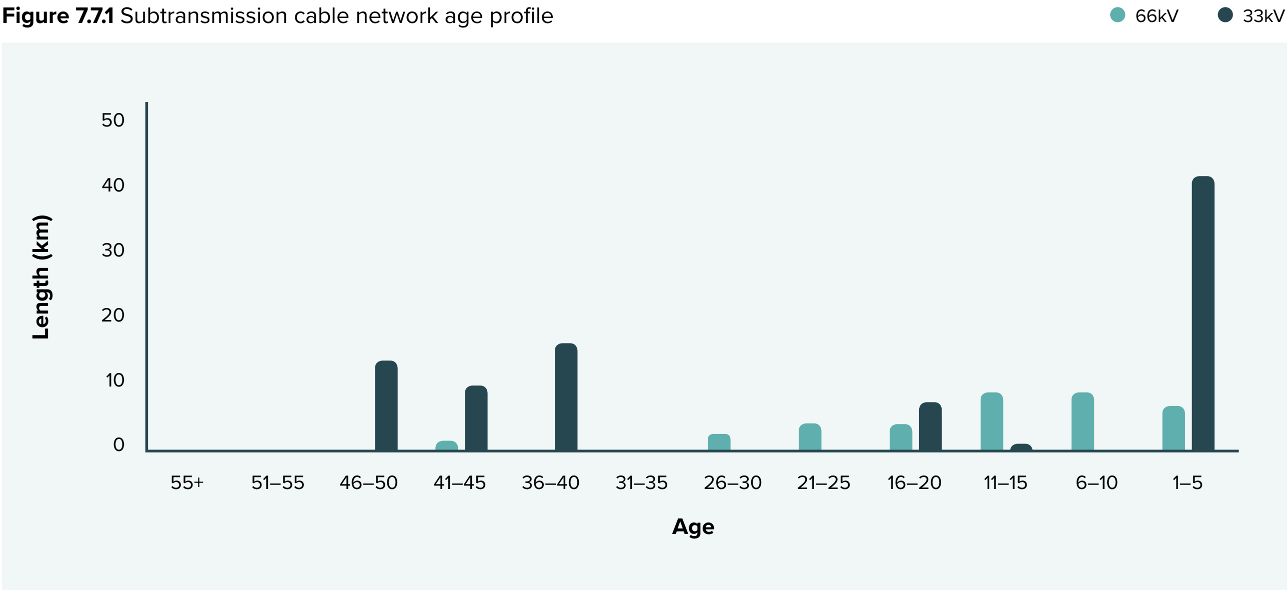
Table 7.7.1 Subtransmission cable length by type

Cable type	Length (km)			Nominal asset life	% of population
	33kV	66kV	Total		
PILCA	2	–	**2**	60	3%
XLPE	36	50	**86**	60	65%
3 core oil	–	40	**40**	60	32%
Sub-total	39	90	**129**		
Total	**129**				

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.

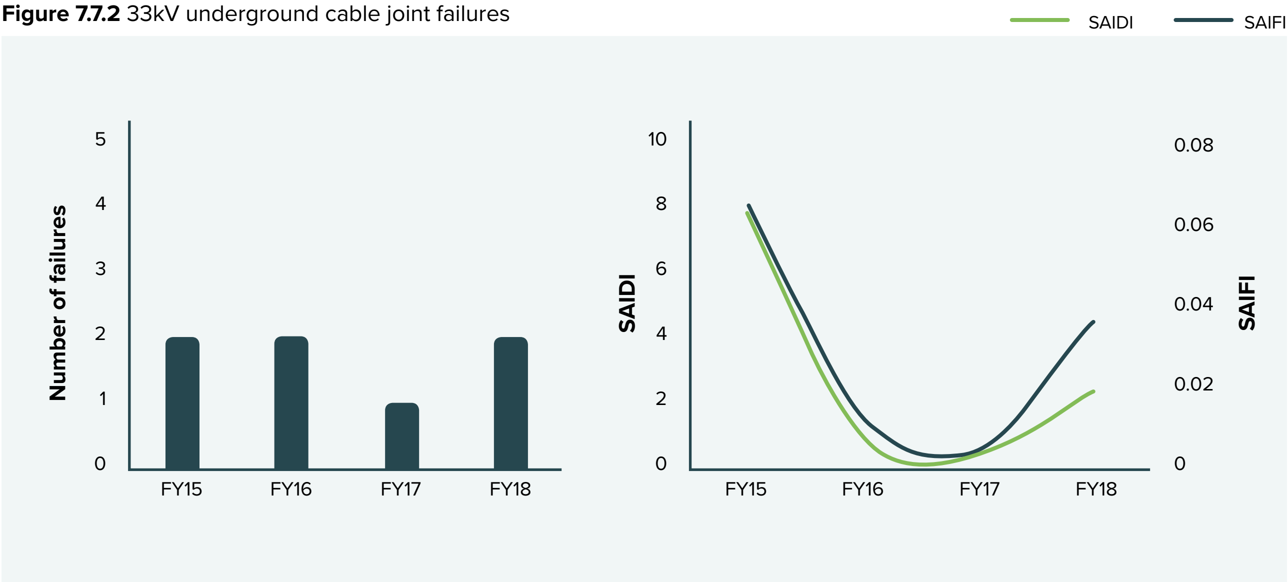
7.7.3.2 Reliability

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.

We operate our 66kV cables conservatively which means they have not been subject to electrical aging mechanisms.

As shown in Figure 7.7.2 our 33kV cable network has experienced seven joint failures since FY15 with no failures prior to that. Depending on the location of the fault, some failures have had an adverse impact on our SAIDI/SAIFI performance. In order to improve this performance we have de-rated the affected circuits while we complete a joint replacement programme (see Section 7.7.4).

Figure 7.7.2 33kV underground cable joint failures



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.

Subtransmission cable failures are rare, but when they do occur, they can significantly impact our customers.

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 cable operational expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	110	110	110	110	110	110	110	110	110	110	**1,100**
Routine and corrective maintenance and inspections	250	250	250	250	250	250	250	250	250	250	**2,500**
Asset replacement and renewal	600	530	530	530	430	430	430	430	430	430	**4,770**
Total	**960**	**890**	**890**	**890**	**790**	**790**	**790**	**790**	**790**	**790**	**8,370**

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. Being a 'sunset' technology, oil filled cables have some disadvantages. They take longer to repair compared to modern XLPE cables, sourcing trained and skilled people to work on them is difficult, and there is a risk of oil escaping to the environment.

Another issue is the mechanical strength of the cable joints. While these joints are suitable for the mechanical stress caused by cyclic loading they are, however, likely to fail during a long duration seismic event such as an Alpine Fault event.

To minimise the risk of failure and to continue investing in the network resilience and provide security and confidence for our community, we will initiate a replacement programme for our oil-filled 66kV cables. We have approximately 40km of 66kV oil filled cables. Our replacement forecast is based on a 10 year programme starting in FY24. We have learned from the earthquakes that dual circuits in the same trench can lead to common mode failure. To ensure resiliency, any new installation will be designed to account for this.

In the next 12 – 18 months we will undertake a review to:

- identify which circuits are most vulnerable
- analyse historic test results to identify the highest risk cable
- identify suitable routes to support the 66kV architecture
- identify what other works at our zone substations may be required as part of this programme
- identify the options and choose a solution

Once completed we will refine our expenditure forecast to better reflect the findings and recommendations of the review. An annual forecast of subtransmission cable replacement in Commerce Commission categories is shown in Table 7.7.5.

Table 7.7.5 Subtransmission cable replacement capital expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Subtransmission	0	0	0	0	4,115	4,115	4,115	4,115	4,115	4,115	**24,690**
Total	**0**	**0**	**0**	**0**	**4,115**	**4,115**	**4,115**	**4,115**	**4,115**	**4,115**	**24,690**

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.

Being a 'sunset' technology, oil filled cables have some disadvantages.

90% of our 2,647km 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 2,647km 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

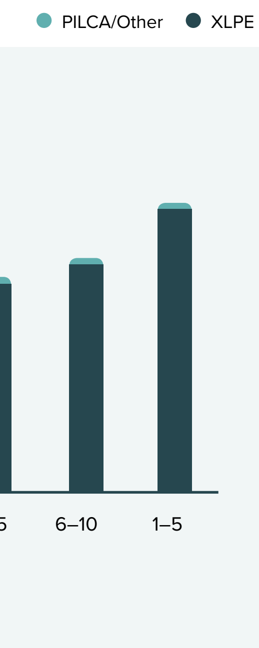
Our 11kV cables are classed as primary and secondary. Primary cables supply network substations from zone substations, secondary cables supply distribution substations from network substations. There are two types of 11kV underground cable in our network:

- **PILCA** – paper insulated lead armour cables normally used up to the voltage level of 33kV
- **XLPE** – cross linked polyethylene insulated power cables can operate at voltage levels from 600V to 420kV

Table 7.8.1 11kV cable length by type

Cable type	Length (km)	Nominal asset life	% of population
PILCA	1,559	70	59%
XLPE	1,088	60	40%
Others	< 1	60	< 1%
Total	**2,647**		

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 FY18, 11kV cable failures contributed to 7% of the total SAIDI and 14% 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 are starting to see a reduction in third party cable strikes and other failure modes in general.

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

We are beginning to see a reduction in third party cable strikes and other failure modes in general. 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 failure and performance is satisfactory.

7.8 Underground cables – distribution 11kV continued

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

7.8 Underground cables – distribution 11kV continued

An annual forecast of operational expenditure in the Commerce Commission categories is shown in Table 7.8.4.

Table 7.8.4 11kV cable operational expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	2,375	2,375	2,375	2,375	2,375	2,375	2,375	2,375	2,375	2,375	**23,750**
Routine and corrective maintenance and inspections	515	515	515	515	515	515	515	515	515	515	**5,150**
Asset replacement and renewal	100	0	0	0	0	0	0	0	0	0	**100**
Total	**2,990**	**2,890**	**2,890**	**2,890**	**2,890**	**2,890**	**2,890**	**2,890**	**2,890**	**2,890**	**29,000**

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 cable replacement capital expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Distribution & LV cables	100	100	100	100	100	100	100	100	100	100	**1,000**
Total	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**1,000**

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 3,087km 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 3,087km and delivers electricity to 2,525km 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

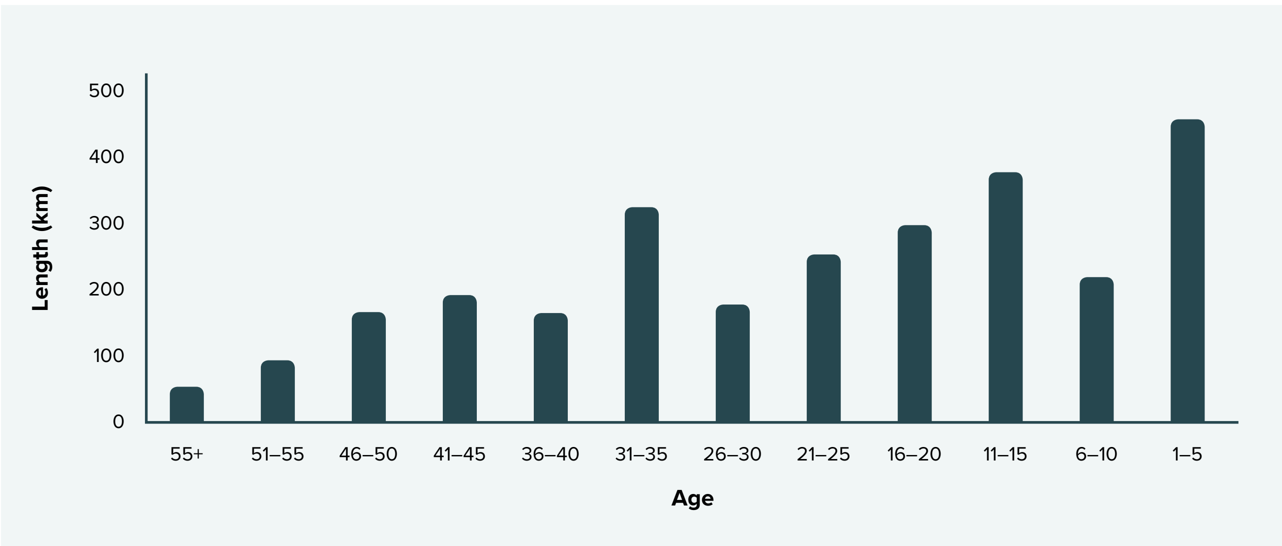
We have two groups of cables: distribution cables and street-lighting cables as shown in Table 7.9.1. They are:

- **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)	Nominal asset life	% of population
PVC	932	80	30%
PILCA	106	80	4%
XLPE	2,049	80	66%
Total	**3,087**		
Street-lighting cable	2,525		

Figure 7.9.1 LV cable network age profile



LV Enclosures

We have two groups of enclosures (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

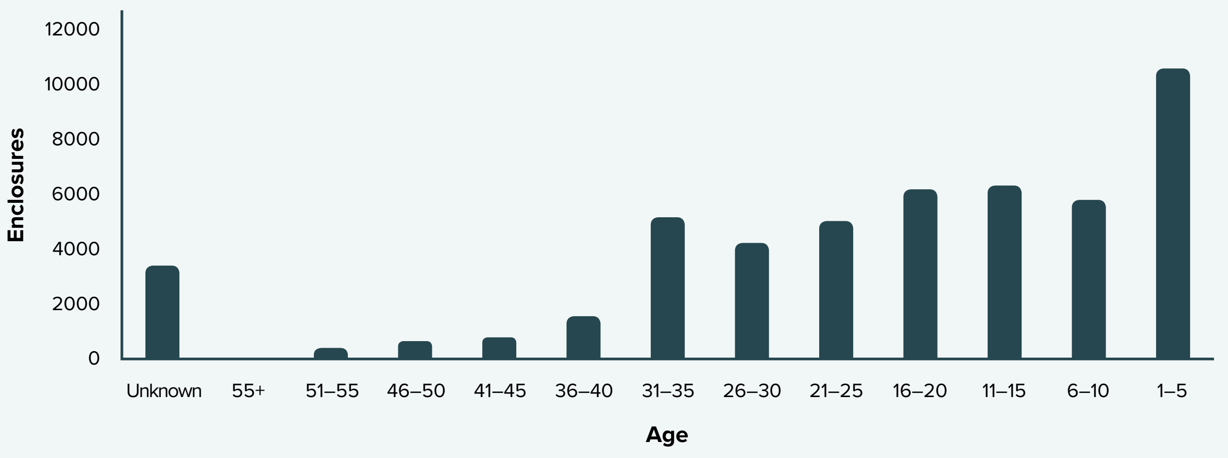
The age profile is shown in Figure 7.9.2.

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	Nominal asset life	% of population
Distribution cabinet	6,303	50	13%
Distribution box	44,019	50	87%
Total	**50,322**		

Figure 7.9.2 LV enclosures age profile



7.9.3 Asset Health

7.9.3.1 Condition

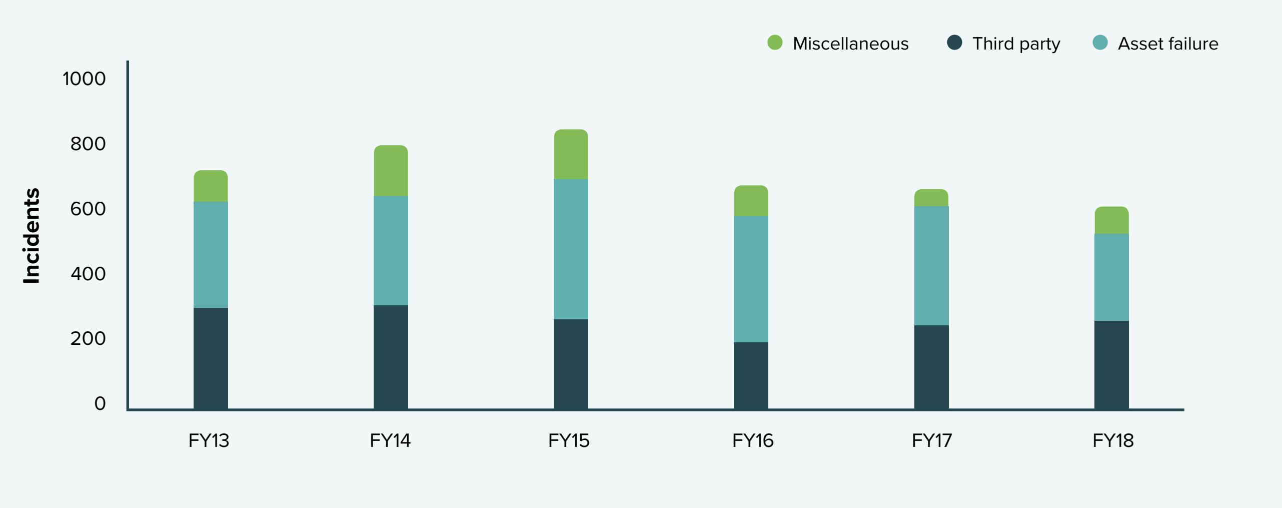
The vast majority of our distribution cabinets and boxes are in good condition. We inspect our distribution cabinets and boxes every five years, with any defects remedied in a subsequent contract. We cannot readily inspect the condition of the LV underground cables. Based on our assessments of expected 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 below 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.

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	**17,550**
Routine and corrective maintenance and inspections	1,135	1,145	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	**10,600**
Total	**2,890**	**2,900**	**2,795**	**2,795**	**2,795**	**2,795**	**2,795**	**2,795**	**2,795**	**2,795**	**28,150**

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Distribution and LV	330	330	330	330	330	330	330	330	330	330	**3,300**
Other network assets	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	1,035	0	**61,035**
Total	**7,830**	**7,830**	**7,830**	**7,830**	**7,830**	**7,830**	**7,830**	**7,830**	**1,365**	**330**	**64,335**

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 and/or have reached the end of their reliable service life. These include some that were acquired as part of our purchase of Transpower spur assets. 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, 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. We have not found a viable vacuum option for this voltage. We have a number of oil fill units some of which were acquired as part of our spur asset purchase.
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 have a number of oil filled units some of which were acquired as part of our purchase of Transpower's spur assets.
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. We only have a limited number of SF_6 circuit breakers.
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.

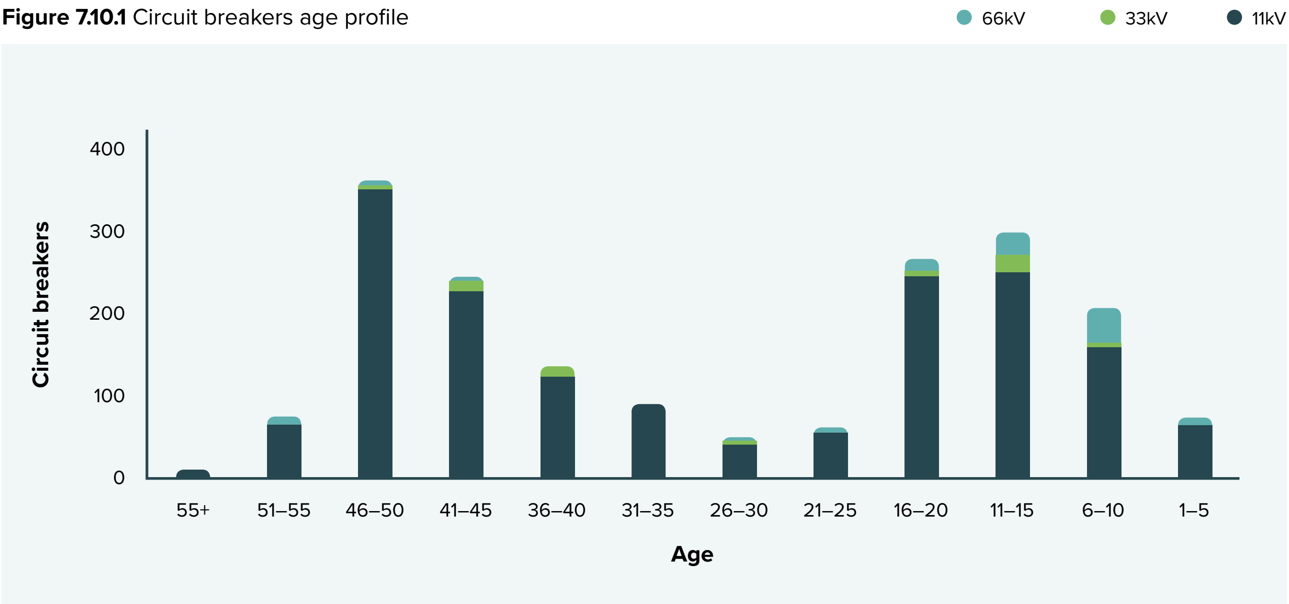
Table 7.10.2 Circuit breaker quantities by type

Voltage	Asset Type	Quantity	Nominal Asset Life	% of population
66kV	Oil CB	15	50	1%
	Gas CB	94	55	5%
33kV	Oil CB	35	50	2%
	Vacuum CB	28	60	1%
11kV	Oil CB	848	45	45%
	Gas CB	35	45	2%
	Vacuum CB	806	50	42%
	Total	**1,861**		

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.

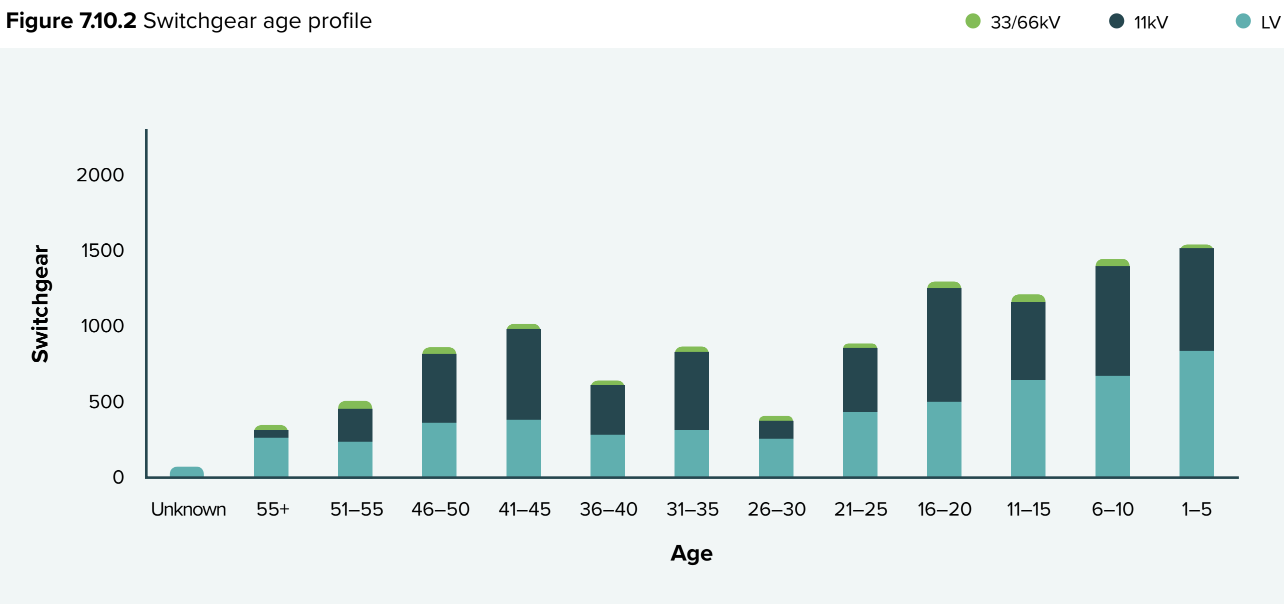
Table 7.10.3 Switchgear description by type

Voltage	Type	Description
66kV / 33kV	Substation Disconnector (DIS)	These are installed in mostly outdoor bus work in zone substations. They are 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 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	Nominal Asset Life	% of population
66kV / 33kV	Substation disconnector	321	45	3%
33kV	Line ABI	15	45	0%
11kV	Line switch	109	45	1%
	Line ABI	769	45	7%
	MSU	4,396	50	40%
	RMU	95	45	1%
	Oil switch, fused and non-fused	25	45	0%
	Sectionaliser	2	45	0%
400V	Low voltage switches	5,234	50	48%
	Total	**10,966**		

Figure 7.10.2 Switchgear age profile



7.10.3 Asset health

7.10.3.1 Condition

Overall our circuit breakers and switchgear are in good working condition. Methods of condition monitoring, for example partial discharge measurement, have enabled us to detect defects at an early stage. The line switches, ring-main units and low voltage switches are generally in good condition. 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.

We developed and use the CBRM model for our high voltage circuit breakers and switchgear. This model utilises asset information, engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal forecast. For more information on CBRM process, see Section 5.6.

Methods of condition monitoring, for example partial discharge measurement, have enabled us to detect defects at an early stage.

The results of this process shows that:

- **66kV / 33kV substation disconnector –** Overall the condition is satisfactory but the CBRM model highlights that some disconnectors acquired in the spur asset transfer currently exceed their reliable service and approximately 30% will reach their end of reliable service life in the next ten years.
- **66kV / 33kV circuit breaker –** The majority are in good condition. A small number are over their reliable service life, these are mainly the bulk oil circuit breakers acquired from Transpower. An ongoing replacement programme is in place to remove these ageing units in order to maintain the current risk profile, ensuring no health and safety incidents relating to these assets and that there is no impact on reliability performance.
- **11kV circuit breaker –** CBRM modelling of our 11kV circuit breakers in our zone substation and distribution substation also showed we are managing a number of ageing circuit breakers in our network, with some of these older assets beyond their reliable service life phase. The age profile of our circuit breakers are shown in Figures 7.10.3 and 7.10.4.

Figure 7.10.3 33kV / 66kV circuit breaker condition profile

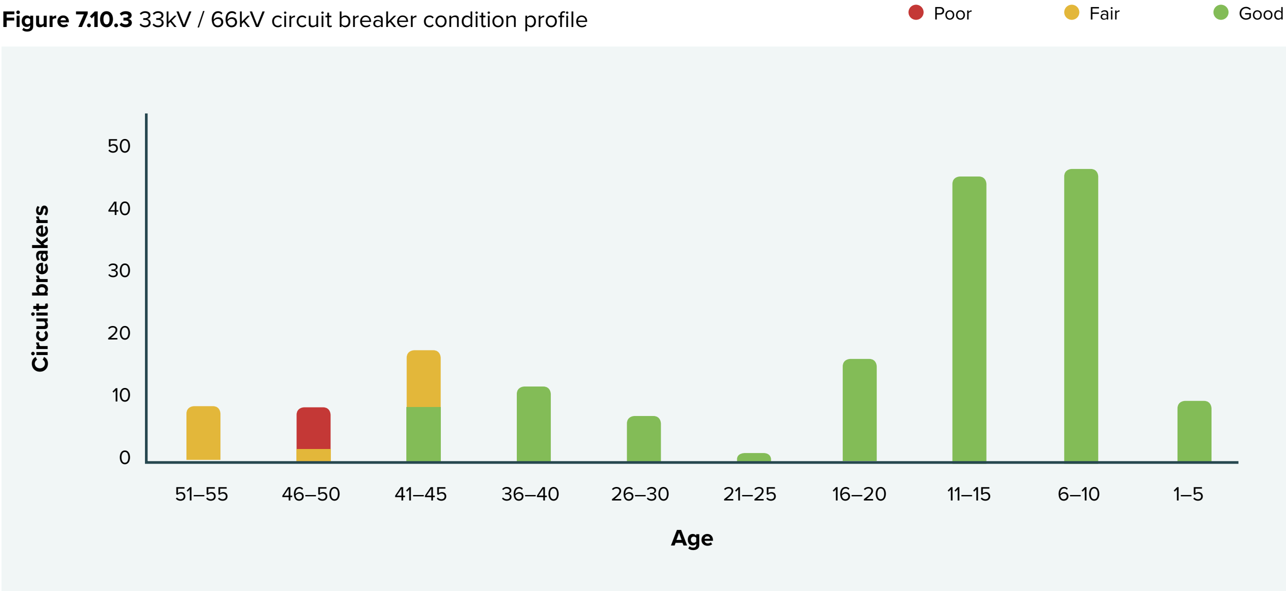
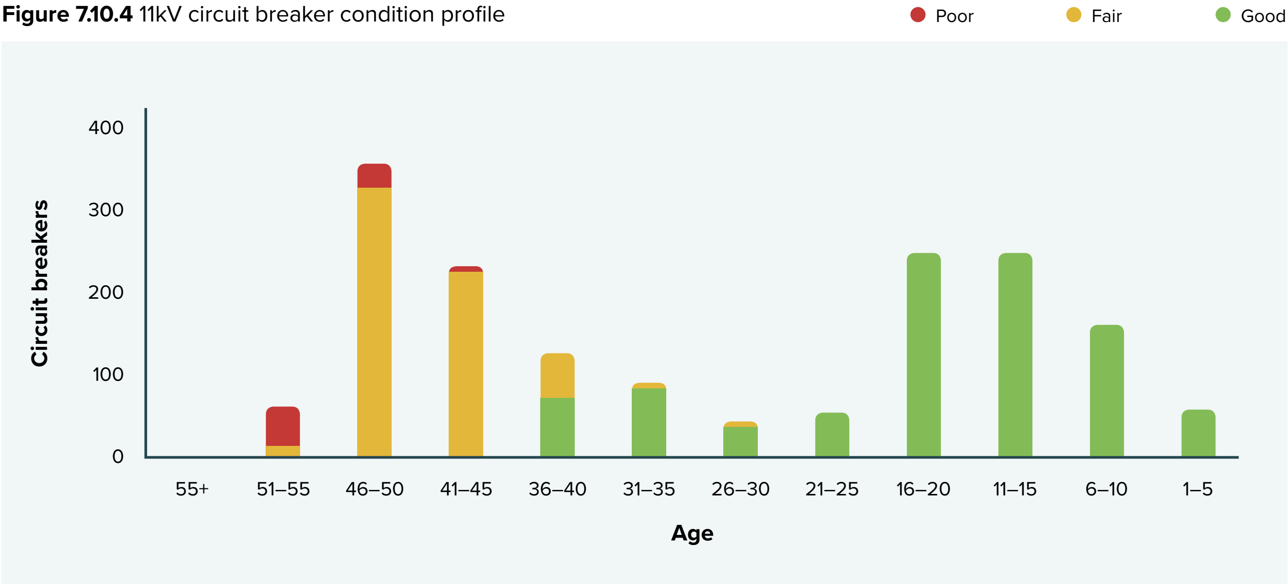


Figure 7.10.4 11kV circuit breaker condition profile



7.10.3.2 Reliability

The five year average reliability contribution for the combined circuit breakers and switchgear is less than 1% of the network SAIDI and SAIFI. Circuit breakers and switchgear contribute 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 potential safety consequences relating to 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. There have been no 66kV and one 33kV circuit breaker failures over the last ten years. There was on average one failure causing an interruption every two years of 11kV indoor circuit breaker for FY10-FY18.
A summary of the performance 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	Some acquired in the spur asset transfer are experiencing performance issues due to misalignment. Furthermore, a number of these have reached the end of their reliable life. We are addressing this issue in our maintenance and replacement programmes. Overall the performance level has been satisfactory with two failures over the last 10 years.
66kV / 33kV / 11kV	Circuit breakers	The overall performance of circuit breakers is satisfactory. However, there is a small proportion of aging oil type 66kV and 33kV circuit breakers from the spur asset transfer. There is also a small proportion of oil filled 11kV circuit breakers in our substations that have poor health index and are at the end of their reliable service life. While the rate of failure is low and currently having little impact on reliability, a failure of these assets can be catastrophic in nature. This therefore presents a risk to maintenance personnel working within the switchyards, as well as a significant impact on reliability should a failure occur. As a result of the critical nature of these assets, we are focused on phasing out all oil filled circuit breakers.
33kV	Line ABI	Although a number of the units are ageing and beyond 50 years old they 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	These are also performing well and are reliable. Any failures in these units are usually due to secondary factors such as cable terminations and are dealt with in our regular inspection and maintenance programme.
	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 objectives 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 reliability based testing and maintenance programme. Parts replacement/ refurbishment if possible or economical. If not replacement
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	Repair if economical and product still supported by manufacturer or spares available. If not, 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 Circuit breakers and switchgear continued

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 SF6 and report any loss to atmosphere • Monitor partial discharge	2 months – Zone substation 6 months – Network substations 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/SF6 • Battery replacement	Every 4 or 8 years – Zone substation 8 years – Network substations 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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	180	180	180	180	180	180	180	180	180	180	**1,800**
Routine and corrective maintenance and inspections	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	**10,800**
Total	**1,260**	**1,260**	**1,260**	**1,260**	**1,260**	**1,260**	**1,260**	**1,260**	**1,260**	**1,260**	**12,600**

7.10.5 Replacement Plan

We have a proactive replacement programme for our circuit breakers and switchgear. One of the tools we use to manage our older assets is CBRM modelling. 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 a number of factors:

- safety
- performance
- condition
- criticality
- maintenance issues
- operation
- logistical support
- working environment
- age

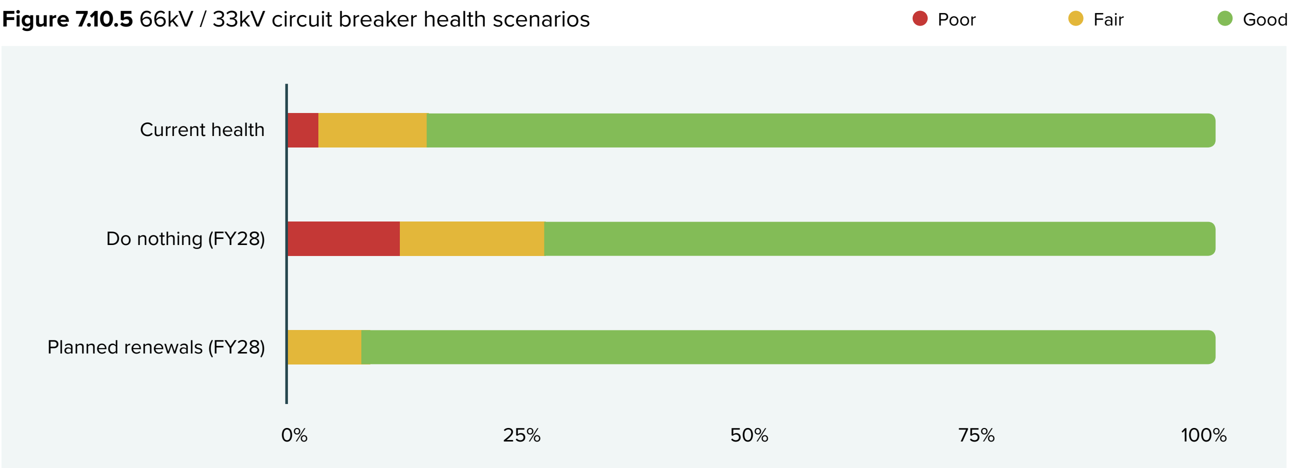
Safety issues are given a high weighting to ensure protection of the public, employees and service providers. Performance and asset condition are considered on an individual basis and are used to develop the replacement programme. The criticality and location, i.e., zone or network substation, is also 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

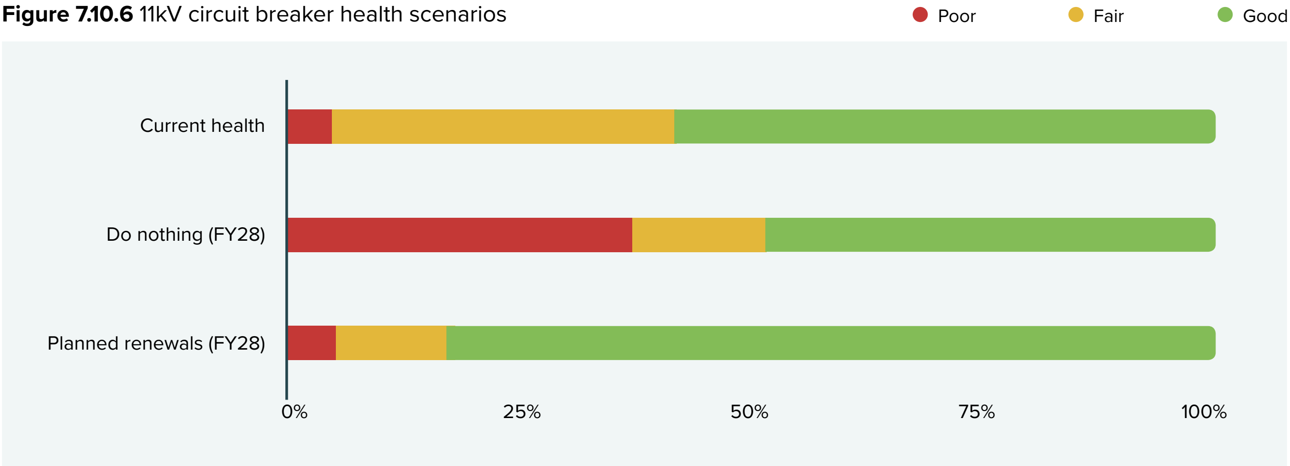


- **Do nothing scenario –** as a means of comparison, we looked at a theoretical scenario without a replacement programme. This showed the risk of a major failure of circuit breakers would increase. This poses a risk on safety of personnel and environmental impacts, which is considered to be unacceptable as it would breach a number of our asset management objectives and service level targets.
- **Planned renewal scenario –** is our preferred option where we continue our current circuit breaker replacement volume. In addition to this will be the anticipated 33kV spur asset (oil type circuit breaker) replacement at Islington substation in FY20 and Hororata substation in FY23. This scenario maintains a steady risk profile with no material increase in condition related risk.

11kV circuit breakers

Our replacement programme will target those assets with additional focus on their network performance criticality. The scenario in Figure 7.10.6 represents an appropriate response to the potential safety risk of ageing 11kV circuit breakers. We anticipate that to maintain the risk to an acceptable level, we will need to replace our circuit breakers at a rate of 3.5% per annum over the AMP period. This volume is necessary as our previous replacement programme was impacted by resources diverted to earthquake recovery work.

Figure 7.10.6 11kV circuit breaker health scenarios



66kV / 33kV substation disconnectors

For these assets, we again used condition and risk scenarios comparison, within CBRM modelling. The targeted replacement scenario is our ongoing programme for substation disconnectors based on their condition and criticality. We are looking to replace 15% of the population over the next five years to maintain the current performance and service level.

33kV line ABI

The relatively small number of older ABI at the end of their reliable service life are progressively being replaced, in our existing programme, by line circuit breakers. Replacement is based on their condition and criticality but it is planned to be a steady number over the next five years.

11kV line ABI

As mentioned in Section 7.10.3.2, a particular model of ABI has a high failure rate. We are three years into the programme of replacing these ABIs with line switches. The programme is expect to be completed by FY22. Our preferred replacement is 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

We replace MSUs installed in the 1960s and 70s with either new MSUs or metal clad RMUs. According to CBRM modelling an increase in replacement volumes is required to maintain our current health and risk profile. Due to resource constraints we plan to replace less than 1% of the population per annum over the next five years, increasing to around 3% per annum in the latter half of the AMP period. We will continue to replace our oil switches for safety reasons over the next five years.

Low voltage switch

We plan to continue our ongoing programme of replacing older exposed bus type switches for safety reasons. We also plan to replace DIN types switches in poor condition. As with our other switchgear replacements, the deciding factors are their condition, criticality and opportunity in terms of cost and resources to be carried out in conjunction with other substation work. It is anticipated that the number to be replaced will remain constant for the next 10 years.

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Zone substations	3,135	3,160	2,100	2,190	3,870	2,820	2,355	1,620	1,605	1,650	**24,505**
Distribution switchgear	4,603	4,816	4,579	4,880	4,509	6,097	8,476	8,898	9,565	9,140	**65,563**
Total	**7,738**	**7,976**	**6,679**	**7,070**	**8,379**	**8,917**	**10,831**	**10,518**	**11,170**	**10,790**	**90,068**

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.

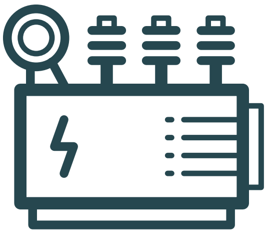
We also have procedures for the environmental management and disposal of Sulphur Hexafluoride (SF_6).

We have also replaced the doors on 11kV indoor vacuum breakers to arc rate them and all 33kV and 11kV boards purchased are now arc rated to IEC standards. Although these do not mean we can defer our asset replacement, they significantly mitigate the safety consequences in the event of an explosive failure.

7.10.6 Innovation

The new 11kV circuit breakers we recently installed at our Waimakariri Zone Substation and Addington have modern new safety features, such as:

- A capacitive voltage indication system allowing voltage indication and phasing to be carried out from the front of the circuit breaker panels
- A new fast acting arc flash mitigation system, which utilises fibre optic sensors to operate a device which shorts 3 phases to earth within 5ms, significantly reducing arc flash damage to equipment and people



We have 85 power transformers installed at zone substations, ranging from 2.5MVA to 60MVA, with the most common type being 66kV and 20/40MVA.

7.11 Power transformers and voltage regulators

7.11.1 Summary

We have 85 power transformers installed at zone substations, ranging from 2.5MVA to 60MVA, with the most common type being 66/11kV and 20/40MVA. 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.

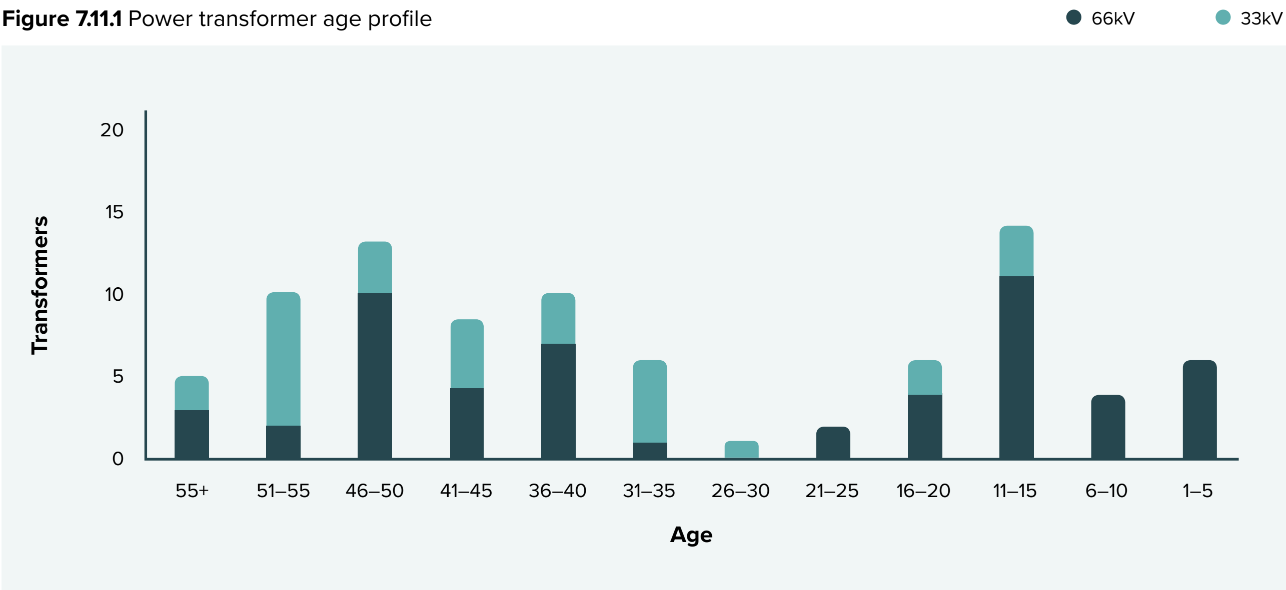
Table 7.11.1 Power transformer quantities by type

Nameplate Rating MVA	66kV			33kV		
	Quantity	Nominal asset life	% of population	Quantity	Nominal asset life	% of population
30/60	2	45	4%			
34/40	2	45	4%			
30/36 (1Ø Banks)	5 (15)	45	9%			
20/40	27	45	50%			
11.5/23	12	45	22%	7	45	23%
10/20				4	45	13%
7.5/10	6	45	11%	7	45	23%
7.5				11	45	37%
2.5				2	45	4%
Total	**54 (64)**			**31**		

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 perform two different functions:

- provide capacity, via voltage regulation, for security against the loss of a zone substation
- provide automatic voltage regulation on fixed tap transformers.

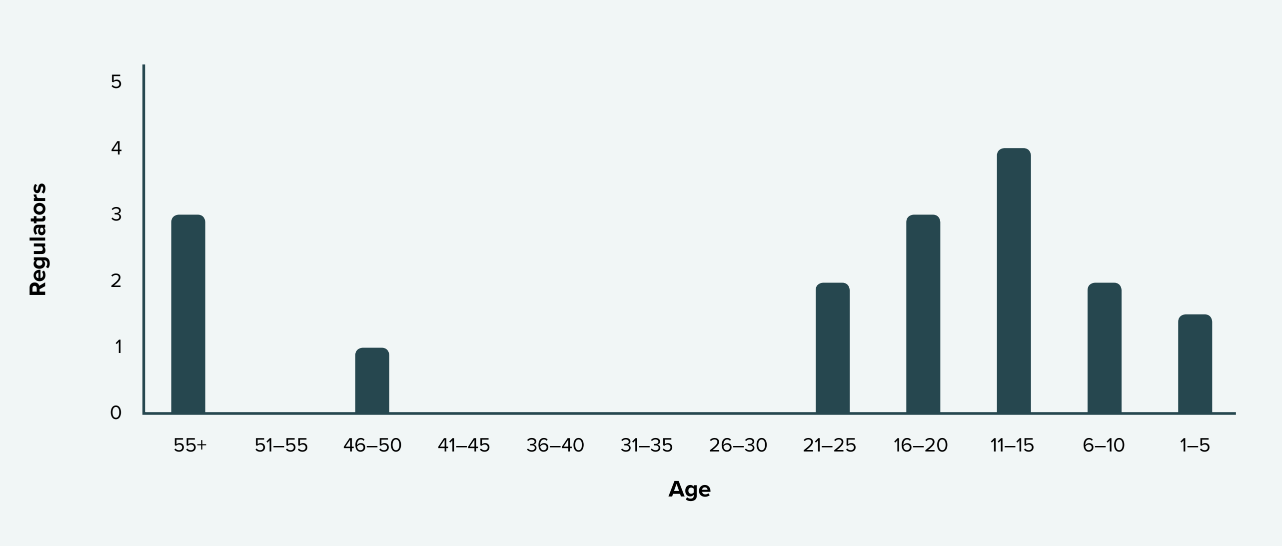
We use a wide range of ratings to cater for different load densities within our network. All regulators are oil-filled, with automatic voltage control by an on-load tap changer or induction. The quantities are listed in Table 7.11.2 and the age profile is shown in Figure 7.11.2.

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	Nominal asset life	% of population
20	3	45	20%
4	11	45	73%
1	1	45	7%
Total	**15**		**100%**

Figure 7.11.2 11kV regulator age profile



Capacitors
To assist voltage regulation within our Banks Peninsula network we have installed three HV fixed step reactive support capacitor banks.

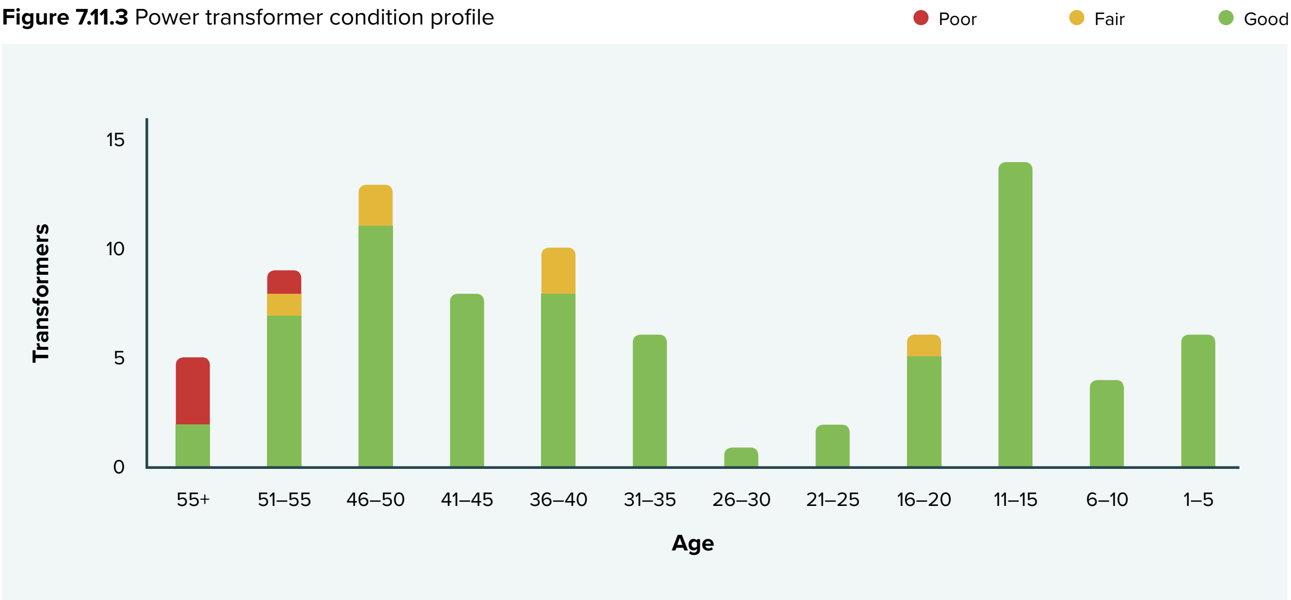
7.11.3 Asset health

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 the ex-Transpower single phase bank transformers at Addington and Bromley substations. These range from 54 to 60 years of age. Our strategy to address these transformers is discussed further in this section.

There is one transformer in fair condition in the 16-20 year age bracket which is an outlier. This condition is attributed to a historic internal fault which leaves a signature in the gas analysis tests. Our ongoing testing has shown the gas test levels have stabilised which indicates the condition hasn't deteriorated further.

Figure 7.11.3 Power transformer condition profile



Regulator
Three 20MVA regulators at Heathcote are an older design. Two are refurbished and working satisfactorily. In FY10 the third regulator was installed for the Lyttelton supply. The condition of our other regulators is good.

Capacitor
There are three capacitor installations providing voltage support. Two are in the Lyttelton harbour area are new and are in good condition. The third is at Akaroa and is in good condition except for a noisy inductor which will be fixed in FY20.

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. These controls enable us to maintain a safe, reliable, resilient system and protect the environment as set out in our asset management objectives in Section 2.8.

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 full load capability
	Lightning	All transformers procured over the last 10 years have thermally uprated papers
Mechanical failure	Tap changer	Surge arrestors fitted to overhead lines and switchyards
	Cooling systems (valves, pumps and fans)	We purchase with vacuum tap changers which are essentially maintenance free
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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	220	220	220	220	220	220	220	220	220	220	**2,200**
Routine and corrective maintenance & inspection	360	360	360	360	360	360	360	360	360	360	**3,600**
Asset replacement and renewal	0	250	250	250	250	250	250	250	250	0	**2,000**
Total	**580**	**830**	**830**	**830**	**830**	**830**	**830**	**830**	**830**	**580**	**7,800**

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
Bromley	replace three single phase banks with two 3 phase transformers	FY21
Addington	replace three single phase banks one or two 3 phase transformers, timing dependent on a wider site strategy	FY24

CBRM modelling has been used to determine the change in overall condition associated with our replacement and refurbishment plan. 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

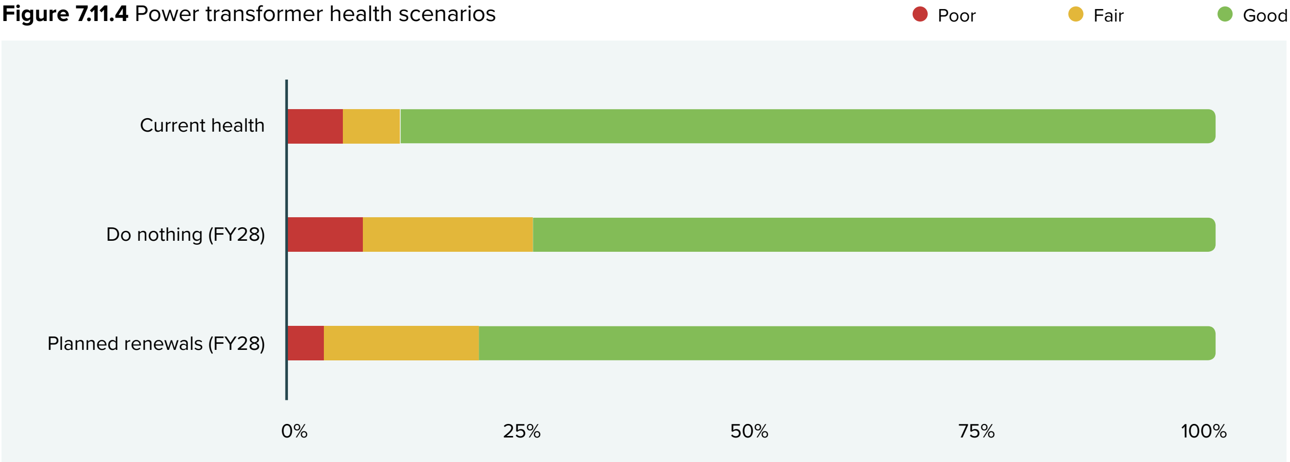


Figure 7.11.4 shows that the target intervention scenario improves the overall condition scores of our transformer fleet. This is largely due to the proposed retirement of the ex-Transpower single phase transformers which are nearing their end of life. Comparing with the 'do-nothing' scenario shows that 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 capital expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Zone substation	0	3,000	0	0	1,500	0	0	0	0	0	**4,500**
Total	**0**	**3,000**	**0**	**0**	**1,500**	**0**	**0**	**0**	**0**	**0**	**4,500**

7.11.5.1 Disposal

During FY19 we disposed of one 33/11kV 2.5MVA power transformer as part of the Teddington zone substation decommission. The site was made redundant due to sufficient 11kV capacity provided by neighbouring zone substations with the aid of capacitive voltage support.

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

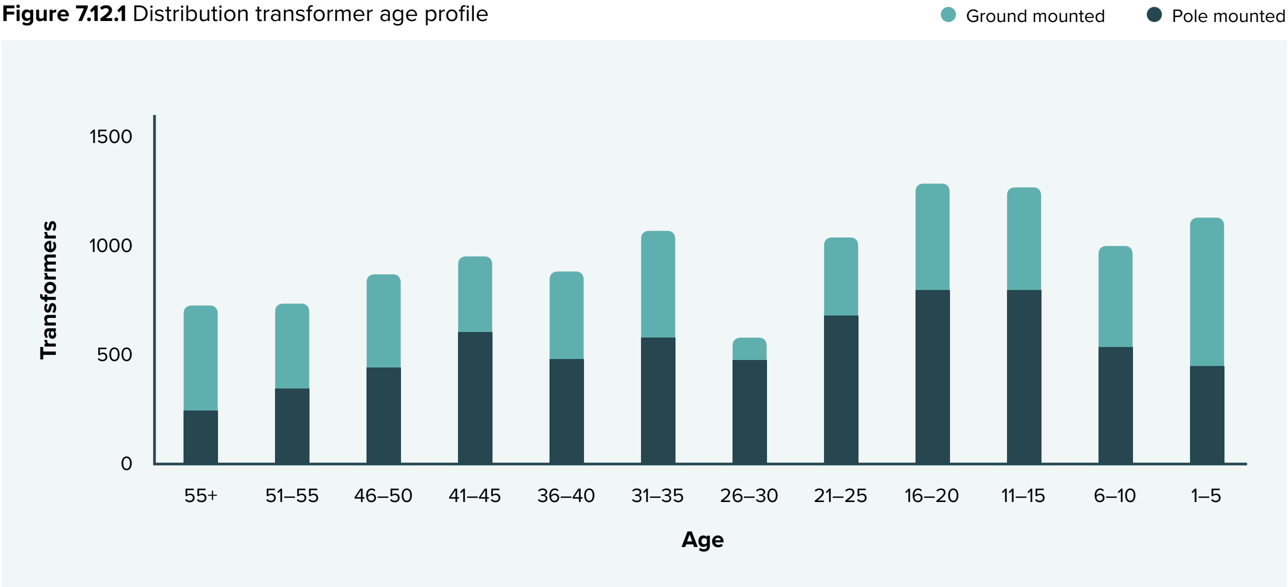
Distribution transformers fall into two main categories: pole mounted or ground mounted. Pole mounted transformers range in rating from 15kVA – 300kVA. With new installations we limit pole-mount transformers to no bigger than 200kVA for safety reasons. Ground mounted transformers range in rating from 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	Expected asset life	% of population	Quantity	Expected asset life	% of population
5-100	393	55	8%	6,101	55	94%
150-500	4,158	55	81%	356	55	6%
600-1000	564	55	11%			
1250-1500	24	55				
Total	**5,139**			**6,457**		

The performance of our distribution transformer fleet is good.

Figure 7.12.1 Distribution transformer age profile



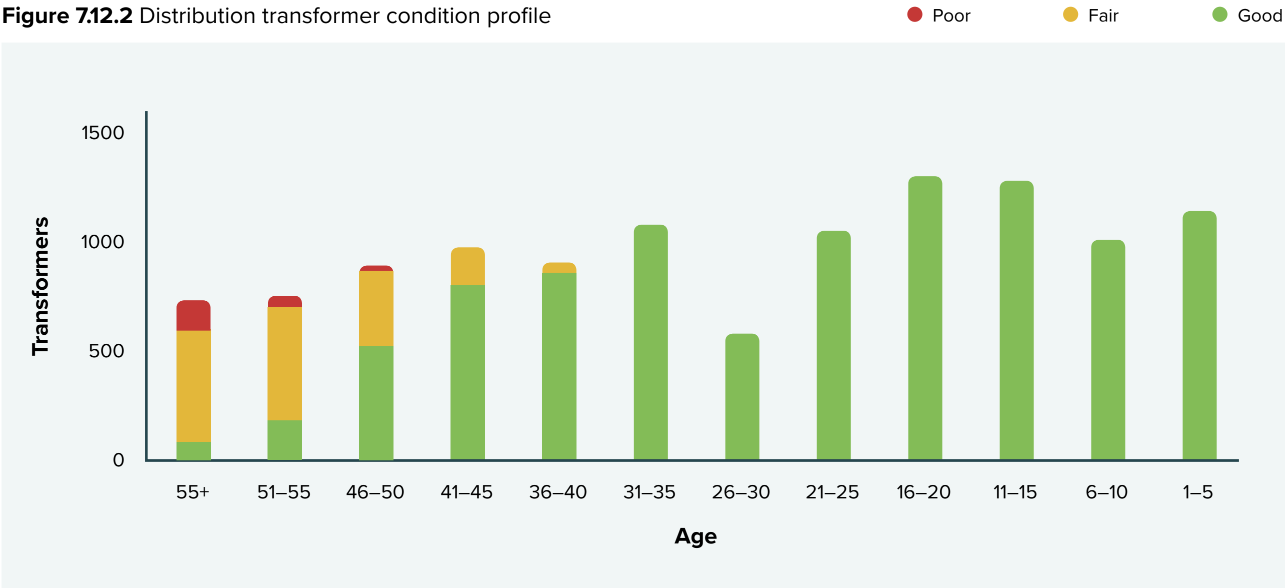
7.12.3 Asset health

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Routine and corrective maintenance and inspections	265	265	265	265	265	265	265	265	265	265	**2,650**
Total	**265**	**265**	**265**	**265**	**265**	**265**	**265**	**265**	**265**	**265**	**2,650**

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Distribution substation and transformer	2,410	2,410	2,410	2,410	2,410	2,410	2,410	2,410	2,410	2,410	**24,100**
Total	**2,410**	**2,410**	**2,410**	**2,410**	**2,410**	**2,410**	**2,410**	**2,410**	**2,410**	**2,410**	**24,100**

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, 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 and we have a programme to replace these assets.

The reliability of the protection system is inherent in fulfilling our objectives of maintaining personnel safety and system reliability.

Protection system upgrade/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.

Historically, substation protection, control and metering functions were performed with electro-mechanical equipment. This electro mechanical equipment was superseded by analogue electronic equipment, most of which emulates the single-function approach of its predecessors. More recently analogue has been superseded by digital electronic equipment that typically provides protection, control and metering functions integrated into a single device. The functions performed by these micro-processor based devices are so wide they have been labelled Intelligent Electronic Devices (IED).

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	Nominal asset life	% of population
Electro-mechanical	1,282	50	47%
Micro-processor based (IED)	1,435	15	53%
Total	**2,717**		

We currently have 22 commissioned Ground Fault Neutralisers (GFN) at our zone substations. The intended function of a GFN is to increase reliability for customers by keeping the power on during transient earth faults, and to reduce the voltage on the faulted phase during earth faults to safe levels.

The fleet of GFNs has been disabled and bypassed since FY17 until we are able to conduct a risk assessment including a Safety in Design review. Some initial work has been undertaken on this assessment and we are now ready to progress this review to the next phase. This year (FY19) we will review, discuss and assess the re-introduction into service of some or all GFNs, following design changes that mitigate operational risks so far as is reasonably practicable.

Our Safety in Design philosophy will be applied to GFNs as if they were a 'new' equipment type being proposed for use on our network. GFNs have been omitted from this AMP until the review is complete.

7.13.3 Asset health

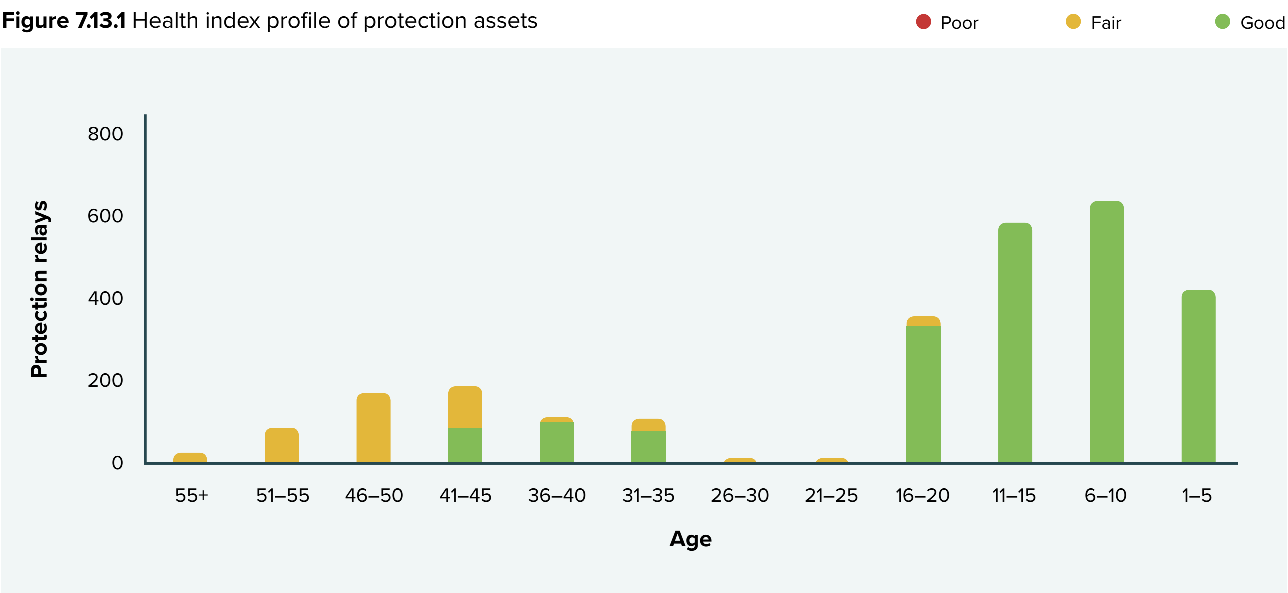
7.13.3.1 Condition

The condition of the protection system assets has been quantified using the process of CBRM. The factors that go into the health index calculation 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 age of our protection assets.

Our CBRM health index profile shows that most of the protection relay population have health indices in the 'Good' range. 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% to SAIDI. Overall they have proven to be robust and are performing well by meeting service level targets. There has been an average of 20 defects per year in recent years and of those, four resulted in an unplanned outage in FY18. 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. Some ex-Transpower spur assets are reaching their end of service life and have deteriorating reliability.

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. Equally likely, protection failure can 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 inspection of our protection systems including 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. Results are recorded and minor adjustments made if necessary.

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	280	280	280	280	280	280	280	280	280	280	**2,800**
Routine and corrective maintenance and inspections	510	510	510	510	510	510	510	510	510	510	**5,100**
Total	**790**	**790**	**790**	**790**	**790**	**790**	**790**	**790**	**790**	**790**	**7,900**

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. This accounts for our ongoing relay replacement, spur asset protection replacement plan for Islington – Addington protection scheme for FY20 and Addington switchboard bus zone upgrade for FY21.

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 replacement capital expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Other network assets	2,555	2,200	2,441	2,085	3,002	3,094	3,156	3,772	3,630	2,792	**28,727**
Total	**2,555**	**2,200**	**2,441**	**2,085**	**3,002**	**3,094**	**3,156**	**3,772**	**3,630**	**2,792**	**28,727**

Our 1,036km 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 1,036km 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 at Papanui, Hawthornden, Middleton, Addington and Islington GXP. These fibre routes provide both protection signalling for the Waimakariri/Papanui/Islington 66kV circuits and in the future Hawthornden/Islington, plus SCADA and other data communications.

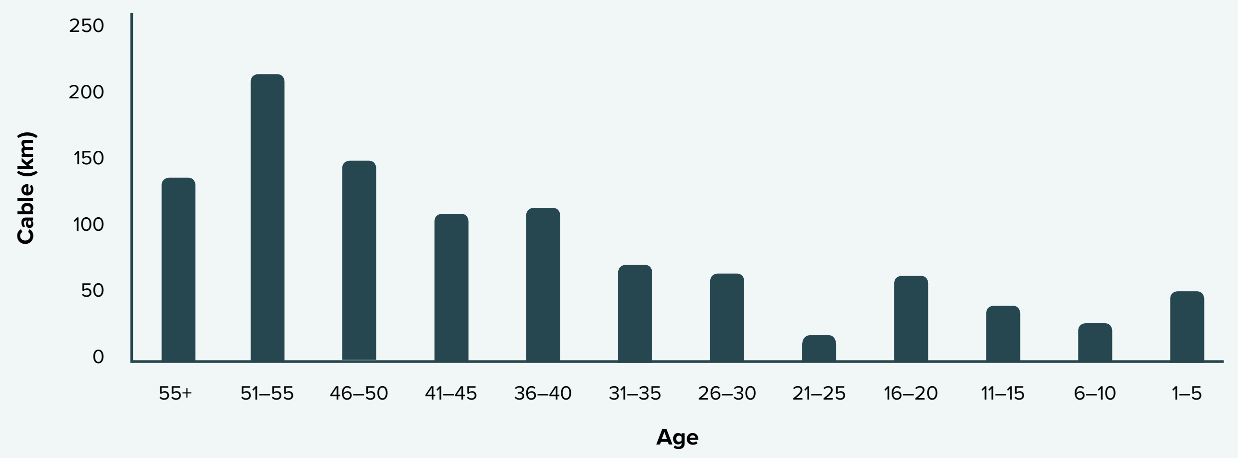
The most common and effective differential protection uses multi-twisted-pair communication cables for end-to-end measurement of electrical parameters on the protected section of cable. As new lengths of primary network cable are laid, a communication cable is laid with the electrical power cable. In general it is uneconomic to lay single pair communication cables, as required only for the unit protection, so multi-pair cables are installed.

It is not possible to use a dedicated communications provider's network for Unit Protection. The unit protection signal levels are incompatible with normal commercial communications. In addition, it is not possible to obtain the very high reliability levels that are provided by a dedicated end-to-end cable laid with the power cable.

The age profile of our communication cables is shown in Figure 7.14.1. The average age of these cables is 40.

When we require new communications routes associated with subtransmission cables or lines we now generally install fibre optic cables in ducts.

Figure 7.14.1 Communication cables age profile



7.14.3 Asset health

The overall condition of our communications 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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	25	25	25	25	25	25	25	25	25	25	**250**
Routine and corrective maintenance & inspection	285	285	285	285	285	285	285	285	285	285	**2,850**
Total	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**310**	**3,100**

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Other network assets	140	140	140	140	140	140	140	140	140	140	**1,400**
Total	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**140**	**1,400**

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 generally in good condition and performing well. Over the next few years, we will replace our analogue ultra high frequency (UHF) transceivers, located with older pole top reclosers, with new reclosers and IP radios. Additional control of the high voltage network and monitoring of the low voltage network is taking place.

These systems are generally in good condition and performing well.

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 at Orion in Wairakei Road and Connetics in Waterloo Business Park, 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.

- **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.
- **SCADA analogue UHF radio** – communicates from the SCADA master station via hilltop repeaters to substations or line circuit breakers. The radio system consists of two hilltop repeaters which utilised licensed frequencies. This system is due for replacement due to obsolescence.
- **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.

The average age of our communication components is five years old. Table 7.15.1 shows the expected nominal life of the various communications components.

Table 7.15.1 Communication component quantities by type

Asset	Quantity	Nominal asset life
Cable modems	78	15
Voice radios	500 (include service providers)	12
Cellular modems/HH PDA's	125 / 39	8
IP data radios	215	12
Radio antennae	215	20
Antenna cable	430	20
Communication masts	35	40
Routers/switches	55	12
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. Any old hardware, typically radio hardware, that fails will be replaced by modern IP equipment.

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

Table 7.15.2 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 7.15.3 and the associated expenditure in the Commerce Commission categories is shown in Table 7.15.4.

Table 7.15.3 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 **Cellular Modems / HH PDAs**	No preventative Maintenance, replaced if faulty.	As required
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 **Antenna Cable**	No preventative maintenance, replaced if faulty, radio links are continuously monitored with faults attended to as soon as detected.	As required
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 7.15.4 Communication systems operational expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	90	90	90	90	90	90	90	90	90	90	**900**
Routine and corrective maintenance and inspections	650	575	575	575	575	575	575	575	575	575	**5,825**
Total	**740**	**665**	**665**	**665**	**665**	**665**	**665**	**665**	**665**	**665**	**6,725**

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 7.15.5 and the forecast expenditure in the Commerce Commission's categories can be found in Table 7.15.6.

Table 7.15.5 Communication system replacement plan

System	Replacement plan
Completion of IP Network	We are progressively upgrading older analogue links when the associated network primary equipment – reclosers, switches etc. – are 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. We are also constructing another link path via Birdlings Flat.
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.
Fibre communications links	We plan to install a fibre link between Islington and Shands Road Zone Substation to support signalling for the protection upgrade on the Islington/Springston 66kV lines.
UHF IP radio system	We are planning to deploy a new technology UHF IP Radio System utilising data speeds below 64kbs to support a large number of small end devices.

Table 7.15.6 Communication system replacement capital expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Zone substation	50	50	50	50	50	0	0	0	0	0	**250**
Other network assets	750	955	265	265	265	265	265	265	265	265	**3,825**
Total	**800**	**1,005**	**315**	**315**	**315**	**265**	**265**	**265**	**265**	**265**	**4,075**

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 Distribution Management System (DMS)

7.16.1 Summary

Our Distribution Management System (DMS) 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 distribution management systems. They are an essential element in our efforts to ensure the safe and effective operation of the network.

Our DMS 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 DMS 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 DMS is a suite of applications designed to monitor and control the distribution network and also to support decision making in the Control Room. Key DMS deliverables include minimisation of the duration of both planned and unplanned interruptions. DMS comes in two systems: core system and ancillary system. See Table 7.16.1 for system descriptions.

Our future planning for the DMS includes the installation of more automated switchgear and on-line load-flow analysis opens up the possibility of implementing an Automated Power Restoration Scheme (APRS). APRS is a DMS application module that allows the DMS to autonomously operate remote switching devices to isolate faults and reconfigure the network to restore supply. We will develop various business and customer interfaces over the next few years as resources permit. We will implement a 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.

Distribution management systems are an essential element in our efforts to ensure the safe and effective operation of the network.

7.16 Distribution Management System (DMS) continued

Table 7.16.1 DMS description

System component	Description
	Core systems
SCADA	A comprehensive SCADA master station is tightly integrated into the DMS and provides telemetered real-time data to the network connectivity model
Network management system (NMS)	At the heart of the DMS 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, enforcing safety rules 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 personal digital assistant (PDA) devices and receive switching instructions directly from the DMS. The network model is immediately updated to reflect physical changes as switching steps are completed and confirmed on the PDA.
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 DMS 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 DMS. Linking DMS records to data from other systems greatly enhances our capabilities in both these areas. DMS data may be presented in reports or used to populate web pages for internal or customer information.

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 remainder of our units are performing satisfactorily and are fully supported by their vendors. While some of our older RTUs no longer have manufacturer support their condition is satisfactory. Those units that do not meet our current operating criteria have been targeted for removal.

Those units that do not meet our current operating criteria have been targeted for removal.

7.16.3.2 Reliability

Generally the DMS system runs at or near 100% reliability. There are some recent performance issues with the capacity, performance and/or availability of the DMS 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 DMS. 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.

Table 7.16.2 DMS 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 DMS 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.

RTUs are maintained on an as-required basis, with component availability the main criteria. Inspections we carry out include:

- weekly general operational checks of equipment software
- annual detailed check of hardware and software systems
- annual operational check of all RTU controls and indications

The forecast expenditure in the Commerce Commission categories is shown in Table 7.16.3.

Table 7.16.3 DMS operational expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	65	65	65	65	65	65	65	65	65	65	**650**
Routine and corrective maintenance and inspections	505	530	530	560	560	610	610	610	610	610	**5,735**
Total	**570**	**595**	**595**	**625**	**625**	**675**	**675**	**675**	**675**	**675**	**6,385**

7.16.5 Replacement plan

DMS 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 DMS 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 FY20-FY21 and FY25-FY26. We are also planning to include LV model in PowerOn in FY22.

Table 7.16.4 DMS replacement capital expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Zone substation	60	60	60	60	60	60	60	60	60	60	**600**
Other network assets	1,580	1,725	1,380	885	1,130	1.680	1,680	235	325	180	**10,800**
Total	**1,640**	**1,785**	**1,440**	**945**	**1,190**	**1,740**	**1,740**	**295**	**385**	**240**	**11,400**

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 strategy focus areas.

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, of which some parts are old and unsupported by the manufacturer. Refurbishment or migration work is currently planned for FY22 and FY23.

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 that runs independently of our load management and network management systems. The system consists of two redundant servers that take information from Orion, Transpower and seven other USI distributors' SCADA systems, monitors the total USI system load and sends 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 the 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 the 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.	15

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 May 2009. The system is maintained on a regular basis but the software platform is out of date. The hardware is out of warranty.	Poor
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

7.17.4 Maintenance plan

Following our upgrade of the load management system in FY18, the master station hardware, operating system, database and Human Machine Interface are current and supported by vendor warranties and maintenance agreements in the short term. Long term we will consider other options described in the replacement plan.

We conduct a daily operational check of our ripple master station during winter and a weekly check during summer. This is supplemented by an annual hardware maintenance programme similar to what we perform on our SCADA master stations. 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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	20	20	20	20	20	20	20	20	20	20	**200**
Routine and corrective maintenance and inspections	325	325	325	325	325	325	325	325	325	325	**3,250**
Total	**345**	**345**	**345**	**345**	**345**	**345**	**345**	**345**	**345**	**345**	**3,450**

We conduct a daily operational check of our ripple master station during winter and a weekly check during summer.

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 FY22 and FY23.

Ripple plant and controllers

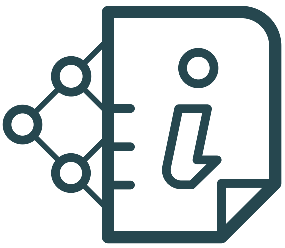
We have budgets to replace components that fail. Components have different expected lives of between 15 and 40 years. The replacement expenditure in the Commerce Commission categories is shown in Table 7.17.6.

Table 7.17.6 Load management system replacement capital expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Zone substation	120	120	120	120	120	120	120	120	120	120	**1,200**
Other network assets	20	20	1,020	770	70	500	70	70	70	70	**2,680**
Total	**140**	**140**	**1,140**	**890**	**190**	**620**	**190**	**190**	**190**	**190**	**3,880**

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. We are currently planning to upgrade Works Management in FY20 and GIS in FY21. Refer to Section 2 for a graphic showing how these and other systems are integrated.

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 group 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 group 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 group.

Other systems – All other systems are supported directly by the Orion Information Solutions group. 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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Routine and corrective maintenance and inspections	570	700	550	550	550	550	550	550	550	550	**5,670**
Total	**570**	**700**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**5,670**

7.18.5 Replacement plan

We are planning to upgrade Works Management in FY20 and carry out GIS enhancement in FY21. 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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Other network assets	430	175	40	175	175	40	175	175	40	175	**1,600**
Total	**430**	**175**	**40**	**175**	**175**	**40**	**175**	**175**	**40**	**175**	**1,600**

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 will build a garage at the Papanui Zone Substation to house our trucks and mobile generators to reduce deterioration from exposure to the elements. We are also looking to upgrade a trailer mounted unit to truck mounted in FY20 and trail 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 Highfield Zone Substation and two are at Papanui. The 11kVA and 30kVA which have no synchronising gear are at Papanui
- 11kV 2,500kVA generators with synchronisation gear presently based at Lyttelton.

Table 7.19.1 Generator types

Voltage	Type	kVA							Total	Avg age
		8 - 30	110	330	400	440	550	2,500		
400V	Mobile		1	1	1	1			13	9
	Building generators		1				2			
	Emergency standby	2					4			
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**	Generators are in good condition. 400kVA rear trailing axle on the V760 truck has on-going issues (see Section 7.19.4)
	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 of the issues during our maintenance and control measures are listed in Table 7.19.3.

Table 7.19.3 Generator failure controls

Generator type	Cause / known Issues	Control measures
Mobile (400V, 400kVA)	Rust has been found on the V760 truck chassis	Proposed garage for mobile generator at Papanui to reduce occurrence of rust
	V760 rear trailing axle has on-going issues	We are planning to remove this generator to fix rust and replace it with a lighter generator so that trailing axle is no longer required. Work planned for FY19
Emergency standby (400V, 550kVA)	Fuel tank leaking into double skin bund	We are currently monitoring bund area
	Radiator pipes are at the end of life	Radiator pipes were replaced
11kV building generator	Radiator cap cracked causing water loss and overheating and unit to trip	Found defective radiator cap and was replaced
	80°C fire fuse link melted and caused the unit to trip	Investigation found the fuse was the wrong rating and was replaced with 100°C link

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 7.19.4.

Table 7.19.4 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.

Generator controllers only have a life span of 10 years. As a result, we are planning to replace two controllers every two years. An annual forecast of generator operational expenditure in the Commerce Commission categories is shown in Table 7.19.5.

Table 7.19.5 Generator operational expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Service interruptions and emergencies	10	10	10	10	10	10	10	10	10	10	**100**
Routine and corrective maintenance and inspections	50	50	50	50	50	50	50	50	50	50	**500**
Total	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**600**

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 unit to truck mounted. The replacement expenditure is covered in Section 8.7 – vehicles.

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

Our mobile trucks have all 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 will begin a programme to install monitoring meters in some of our distribution transformers over the AMP period.

7.20 Monitoring

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. As discussed in Section 6, we will begin a programme to install monitoring meters in some of our distribution transformers over the AMP period. The programme will slowly ramp up and therefore the operational expenditure for monitoring will reflect that.

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	63	40	54%
Voltage Transformers	40	40	34%
Quality Meters	14	15	12%
Total	**117**		

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.

In the past, our power quality management has been largely reactive. We investigate customer complaints and generally find these stem from the customer's own equipment or operation. The general underlying power quality performance of the network is satisfactory, and it is unknown if it is deteriorating with time as an increasing number of non-linear loads are connected to the network. These non-linear loads, which frequently reduce network power quality, are also generally more sensitive to the very power quality issues they help to create.

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. The slow increase in operational expenditure is due to more units being installed in our distribution transformers for the purpose of low voltage monitoring.

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Routine and corrective maintenance and inspections	115	125	235	255	285	300	320	335	360	385	**2,715**
Total	**115**	**125**	**235**	**255**	**285**	**300**	**320**	**335**	**360**	**385**	**2,715**

7.20.5 Replacement plan

Table 7.20.4 shows the replacement capex in the Commerce Commission's categories. Some of the GXP meters are due for replacement in FY20. The expenditure for the remaining period will be used for replacing end of life meters and metering equipment.

Table 7.20.4 Monitoring replacement capital expenditure (real) – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Other network assets	245	185	185	185	185	185	185	185	185	185	**1,910**
Total	**245**	**185**	**185**	**185**	**185**	**185**	**185**	**185**	**185**	**185**	**1,910**

8

Supporting our business

Photo: Our Network Lifecycle team plays an important role in our asset management planning.

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 begun a restructure of our systems operations and network support team to position us appropriately to meet our customers' present and future needs. The new team structure ensures we are able to deliver the initiatives and projects in this AMP and into the future.

We restructured our teams 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 addition to re-scoping existing roles, our organisational plans establish more than six new leadership roles including appointing a Network Strategy and Transformation Manager to champion our network strategic thinking with a focus on new technologies innovation and continuous improvement. In late 2018 we appointed a new General Manager, Customer and Stakeholder to further our objectives to connect and collaborate with our customers and community.

These organisational changes and other initiatives to support customer growth, 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
- **Network management** – our data systems provide vital information to assist our asset team to make informed and economic decisions about the lifecycle and growth of our network. In an increasingly sophisticated world of data mining we will be taking on additional specialist analytics staff to provide deeper insights into the existing and new data we collect and develop strategies for how we can provide data to those who require it
- **Network operations** – we are adding resource to adequately support system enhancements to our SCADA operating system, including those required by our low voltage network monitoring. These systems are important for operational agility that will support customer choice along with improved quality of supply outcomes, and to keep our people and the public safe
- **Engineering** – adding resource to widen our capability and transition knowledge of our overhead assets
- **Works delivery** – as our projects and substations become more complex, we require additional project management capability to support our ability to deliver as described in section 10 , ensure safety and a quality outcome for our customers, the public and stakeholders
- **Procurement and property** – to support the planned increase in projects we will add resource to our procurement team with a particular focus on managing access to our network on private property

8.3 System operations and network support

The systems operations and network support functional area covers the teams managing our network, including our contact centre 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 strategy and transformation

Our network strategy and transformation manager:

- engages with other teams across Orion, to develop network strategies and approaches to achieve our network strategic objectives and meet our customers' evolving needs
- identifies and brings forward new technologies and ways of thinking and working
- works with other teams to assist in the introduction of new technology, systems and ways of working including investigations, recommendations, business case development and programme governance
- determines the key differences between what is required of the network, what it is presently able to deliver and improvement and implementation strategies
- reviews opportunities for continuous improvement and develops action plans to achieve this

8.3.3 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 engineering development programme.

There are four teams in the group:

Lifecycle & network 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 developing 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 to be tendered
- monitors the completion of works to our budget as set out in the AMP

Asset data systems 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

Engineering development programme:

- this programme mentors and develops our people as they progress through their focussed training

8.3.4 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

8.3.5 Customer and stakeholder – contact centre team

Our contact centre team is a key point of contact for our customers. The team:

- operates 24/7 and responds to approximately 3,000 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
- the team also supports other parts of the business when they can, from processing customer connections to providing administrative and support services

8.3.6 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

8.3.7 Works delivery team

The works delivery team puts our planned work into action. The team:

- manages works contracted through our procurement and property services team
- carries out non-scheduled works to maintain the safety and integrity of the network
- assists with the formulation and coordination of the Asset Management Plan, annual plans and budgets
- has overall responsibility for the delivery of the contracted works
- arranges urgent work when required, through an emergency contract
- undertakes the management of strategic and key major projects as required. These projects are required to be delivered with effective and identified key strategic outcomes
- ensures effective support to ensure network reinforcements, undergrounding, and network expansions are achieved in a coordinated and timely manner
- manages Orion's property assets, from kiosks to substations to office buildings

8.3.8 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

8.3.9 Procurement and property services team

This team ensures Orion gets value for money and the level of service we expect from the services we contract in. The team consists of our contract delivery and property services teams.

Contract delivery 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

Property 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

8.3.10 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

8.3.11 System operations and network support expenditure forecast

The forecast for our operational expenditure for the activities of each of these teams in FY20 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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Infrastructure management	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	**14,790**
Network strategy and transformation	161	161	161	161	161	161	161	161	161	161	**1,610**
Network management	3,573	3,666	3,666	3,666	3,666	3,666	3,666	3,666	3,666	3,666	**36,567**
Network operations	7,028	7,050	7,493	7,521	7,549	7,576	7,605	7,632	7,660	7,688	**74,800**
Contact centre	792	792	792	792	792	792	792	792	792	792	**7,920**
Engineering	1,900	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	**19,711**
Works delivery	2,869	2,869	2,869	2,869	2,869	2,869	2,869	2,869	2,869	2,869	**28,690**
Customer connections	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050	**20,500**
Procurement and property services	1,244	1,244	1,244	1,244	1,244	1,244	1,244	1,244	1,244	1,244	**12,440**
Quality, health, safety and environment	649	634	629	634	629	629	629	634	629	629	**6,325**
Asset storage	500	500	500	500	500	500	500	500	500	500	**5,000**
Less capitalised internal labour	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	**(20,840)**
Total	**20,161**	**20,340**	**20,778**	**20,811**	**20,834**	**20,861**	**20,890**	**20,922**	**20,945**	**20,973**	**207,518**

8.3.12 Engineering Development Programme

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.

We began a review of the programme in 2018 to look at ways we could improve its efficiency and outcomes. These include:

- assessing the suitability and performance of our training partners
- considering the branding and reach of the programme to ensure continuing interest and diversity of applicants
- reviewing how participants progress through the business including the breath of their exposure across Orion
- seeking feedback from current and recent graduates of the programme and considering this in our thinking and improvement plans
- reviewing the administration and support of participants to ensure consistency and value

Of our current permanent staff, 19 people are graduates of our Engineering Development Programme. 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 Business support

Around one quarter of our people work in this functional area.

8.4.1 Senior leadership

The senior leadership team sets the direction of the company, provides overall company leadership and oversees key stakeholder interaction.

8.4.2 People and capability

This team provides strategic, tactical and operational support and advice to the business in the people/HR space, including payroll.

By supporting our leaders and managers to build capability we seek to achieve the best organisational results through our people. The team also leads:

- wellbeing
- employer brand-attraction

8.4.3 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.

8.4.4 Information solutions

This team is responsible for our software and information technology infrastructure maintenance, and maintaining our annual software maintenance agreements for both larger corporate systems, financials, document management, and payroll, and productivity software. Orion's maintenance agreements with software providers cover both on-premise systems, supported directly by information solutions, and off-premise, cloud based systems.

A key element of our software maintenance agreements is that we ensure we pre-purchase upgrades, service providers deliver standard product enhancements and performance and security related "patches" are made available. We review all our 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 operations, system development/business change and the administration of the real time systems which are used to operate Orion's electricity network.

8.4.5 Commercial

This team's responsibilities include pricing, regulation, billing and future development. This team also 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

8.4.6 Customer and stakeholder engagement

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

8.4.7 Governance and risk

This team provides support for the board and senior leadership team and it is also responsible for:

- our overall risk framework
- our insurance programme
- special projects

8.4.8 Board

We have a board of six non-executive directors, with extensive governance and commercial experience.

8.4.9 Insurance

We purchase insurance to transfer specified financial risks to insurers. The fees forecast are shown in Table 8.4.1.

8.4.10 Business support operational expenditure forecast

The forecast for the activities of each of these teams in FY20 dollar terms can be found in Table 8.4.1.

8.4 Business support continued

Table 8.4.1 Business support operational expenditure – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Senior leadership	5,251	4,501	4,251	4,251	4,251	4,251	4,251	4,251	4,251	4,251	**43,760**
People and capability	978	919	934	919	934	919	934	919	934	919	**9,309**
Finance	1,323	1,363	1,303	1,383	1,303	1,363	1,323	1,363	1,303	1,393	**13,420**
Information solutions	3,664	3,691	3,699	3,689	3,691	3,699	3,664	3,691	3,699	3,664	**36,851**
Commercial	2,112	2,112	2,112	2,112	2,112	2,112	2,112	2,112	2,112	2,112	**21,120**
Customer and stakeholder engagement	2,616	2,874	2,997	3,062	3,062	3,062	3,062	3,062	3,062	3,062	**29,921**
Governance and risk	255	259	284	274	284	274	284	274	284	274	**2,746**
Insurance	2,065	2,860	3,175	3,243	3,313	3,384	3,457	3,531	3,608	3,686	**32,322**
Corporate properties	914	918	922	926	928	930	932	932	932	932	**9,266**
Vehicles	(990)	(990)	(990)	(990)	(990)	(990)	(990)	(990)	(990)	(990)	**(9,900)**
Less capitalised internal labour	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	**(5,220)**
Total	**17,666**	**17,985**	**18,165**	**18,347**	**18,366**	**18,482**	**18,507**	**18,623**	**18,673**	**18,781**	**183,595**

Notes to Table 8.4.1:

- The Property expenditure shown here is before any depreciation expense is recognised as depreciation does not form part of business support operational expenditure.
- We capitalise $0.3m of internal labour to IT projects each year.
- The Fleet surplus shown above excludes depreciation expense and insurance.

Table 8.4.2 Board of directors' fees and expenses

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Board of directors' fees and expenses	426	426	426	426	426	426	426	426	426	426	**4,260**
Total	**426**	**426**	**426**	**426**	**426**	**426**	**426**	**426**	**426**	**426**	**4,260**

8.4.11 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 our most significant non-network assets, buildings, corporate information systems and vehicles, follow in Sections 8.5 to 8.7.

8.5 Corporate properties

8.5.1 Asset description

Our corporate property portfolio covers our administration building at 565 Wairakei Road, Connetics' Waterloo base and rental properties throughout the Canterbury region. Our corporate properties vary in both construction and age.

- **Administration building** – our Wairakei Rd administration building was built in FY14.
- **Connetics' Waterloo base** – Connetics moved to a new, purpose-built facility in Waterloo Business Park in FY18 to provide a more operationally efficient and resilient base for its operations. Orion owns the depot with Connetics entering a long-term 'arms-length' lease. The building was completed in late 2017 and Connetics moved in in early 2018.
- **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.

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

We are a lifelines utility under the Civil Defence Emergency Management Act 2002, providing essential services to the community.

8.5.2 Maintenance plan

We have no assigned 'end of life' for our corporate properties. Our property asset management programme ensures our corporate property is managed in a manner that is consistent with Orion's corporate obligations to deliver an effective and efficient service.

We carry out regular inspections of our buildings to ensure they remain in good condition and any need for maintenance is identified. Several databases are used to assist us with the management process such as our asset register and our works management system. The risks that our corporate buildings are exposed to are listed below, in no particular order of importance:

- seismic damage
- liquefaction and subsidence
- defective drainage and guttering
- roof leaks
- vegetation/tree roots
- vandalism – repairs carried out as soon as reported
- 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 – Opex – Non network and Table 8.4.1

8.5.3 Replacement plan

We have no replacement plan for our corporate properties. These assets are maintained to ensure they provide the required levels of performance. Our budgeted replacement costs are in Section 9.2.4 — Capex — Non network.

8.6 Corporate information systems

8.6.1 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 the physical tools for access to our information systems. In most cases we manage our computing infrastructure rather than outsource to third parties 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.

In some cases however it is more appropriate to deliver services on a system hosted by a third party, 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 infrastructure has recently been upgraded to replace aging and out of warranty equipment. Capacity and performance are adequate for the period of this plan. Having dealt with server infrastructure our attention now turns to the Storage Area Network (SAN) which is approaching end-of-life and requires regular attention to ensure business continuity is maintained. This is not only due to the age of the equipment but also to lack of disk space. The capacity and performance are considered mostly adequate but a review of alternative solutions and an upgrade are currently under evaluation.
- **Physical servers** – PowerOn servers and telephony servers have been replaced as part of a complete lifecycle upgrade of systems. The health of these servers is 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.

8.6.2 Maintenance plan

All systems are supported directly by our information solutions group with vendor agreements for third tier support where appropriate.

License costs are considered to 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 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.

Our budgeted maintenance costs are shown in Section 9.2.3 – Opex — non network and Table 8.4.1.

8.6.3 Replacement plan

We employ a standard change management approach to all software and hardware systems. Major changes to all corporate business information systems will follow the predefined steps of project proposal/concept socialisation, business case and approval, business requirements and implementation via a Project. 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 – Capex – Non network.

8.7 Vehicles

8.7.1 Asset description

We own 97 vehicles to enable us to operate and maintain the electricity network, engage with the community and respond to any events. Our goal is to ensure we have the right vehicle in the right place at the right time with an appropriately trained driver. Around 28% of our passenger fleet has electric drive capability.

Table 8.7.1 Vehicle quantities and type

Description	Quantity	Lifecycle
Generator truck	3	20 years
Network operator utility	20	5 years or 200,000 km
Electric Vehicle (EV)	3	6 years
Plug-in Hybrid EV (PHEV)	18	6 years
Other	53	4 years on average (earlier for high km's)
Total	**97**	

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.

Around 28% of our passenger fleet has electric drive capability.

8.7.2 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 – Opex – Non network and Table 8.4.1.

8.7.3 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 purpose and where there is a demonstrable gain in safety, efficiency, reliability and value for money.

Our budgeted replacement costs are in Section 9.2.4 – Capex – Non network.

8.7.3.1 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
- environment 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

8.7.3.2 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.

$282m

Network operating expenditure

$395m

Non-network operating expenditure

$730m

Capital expenditure

9 Financial forecasting

Photo: Orion’s network extends to Banks Peninsula and the sea-side town of Akaroa, nestled in the heart of an ancient volcano.

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. Whether or not these projects will proceed, and the timing of them, is determined by Government, local authorities, developers, our customers and stakeholders.

Changes described are referenced to our last published AMP for the period from 1 April 2018 to 31 March 2028.

All forecast figures in Section 9.1 are in (FY20) dollar terms. Capex and opex forecasts allow for the capitalisation of $2.6m of internal labour into capital works. This is apportioned as follows:

- Network capex $2.3m
- Non-network fixed assets $0.3m

Schedule 11a in Appendix F allocates this capex across the Commerce Commission's disclosure categories. Where relevant, the forecasts include this capex as a single line item. However, in all other sections within this AMP we provide forecasts which exclude the internal capitalised labour, that is, we focus on direct external project expenditure. Appendix F also has these section 9 tables, reworked to include general CPI inflation and other cost escalators.

The following financial forecasts exclude costs for major projects substantially started in FY19 (carry-over costs in FY20). Carry-over costs in FY20 are likely to be largely offset by delays/deferrals of spending on forecast FY20 projects into FY21.

9.1.1 Opex – network

Table 9.1.1 Opex network – $000

Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Subtransmission overhead lines	2,110	2,020	2,045	2,020	2,020	2,020	2,020	2,020	2,020	2,045	**20,340**
11kV overhead lines	7,070	7,070	6,715	6,715	7,115	7,115	7,115	6,715	6,715	7,115	**69,460**
400V overhead lines	3,635	3,635	4,035	4,035	3,635	3,635	3,635	4,035	4,035	3,635	**37,950**
Earths	280	280	280	280	280	280	280	280	280	280	**2,800**
Subtransmission underground cables	960	890	890	890	790	790	790	790	790	790	**8,370**
11kV underground cables	2,990	2,890	2,890	2,890	2,890	2,890	2,890	2,890	2,890	2,890	**29,000**
400V underground cables	2,890	2,900	2,795	2,795	2,795	2,795	2,795	2,795	2,795	2,795	**28,150**
Asset information management	570	700	550	550	550	550	550	550	550	550	**5,670**
Storms	245	245	245	245	245	245	245	245	245	245	**2,450**
Monitoring	115	125	235	255	285	300	320	335	360	385	**2,715**
Protection	790	790	790	790	790	790	790	790	790	790	**7,900**
Communication cables	310	310	310	310	310	310	310	310	310	310	**3,100**
Communication systems	740	665	665	665	665	665	665	665	665	665	**6,725**
Control systems	570	595	595	625	625	675	675	675	675	675	**6,385**
Load management	345	345	345	345	345	345	345	345	345	345	**3,450**
Switchgear	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	**12,600**
Transformers	845	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	845	**10,450**
Substations	570	570	570	570	570	570	570	570	570	570	**5,700**
Buildings and enclosures	1,250	1,250	1,250	1,190	1,190	1,230	1,180	1,180	1,180	1,180	**12,080**
Grounds	590	590	590	590	590	590	590	590	590	590	**5,900**
Generators (fixed)	60	60	60	60	60	60	60	60	60	60	**600**
Total	**28,195**	**28,285**	**28,210**	**28,175**	**28,105**	**28,210**	**28,180**	**28,195**	**28,220**	**28,020**	281,795
Totals from 1 April 2018 AMP	**28,540**	**27,640**	**27,595**	**27,410**	**27,410**	**27,510**	**27,460**	**27,460**	**27,460**	n/a	277,520

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	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
System interruptions and emergencies	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	**89,900**
Vegetation	3,950	3,950	3,950	3,950	3,950	3,950	3,950	3,950	3,950	3,950	**39,500**
Routine & corrective maintenance and inspections	13,140	13,240	13,165	13,130	13,160	13,165	13,135	13,150	13,175	13,225	**131,685**
Asset replacement and renewals	2,115	2,105	2,105	2,105	2,005	2,105	2,105	2,105	2,105	1,855	**20,710**
Total	**28,195**	**28,285**	**28,210**	**28,175**	**28,105**	**28,210**	**28,180**	**28,195**	**28,220**	**28,020**	**281,795**
Totals from 1 April 2018 AMP	**28,540**	**27,640**	**27,595**	**27,410**	**27,410**	**27,510**	**27,460**	**27,460**	**27,460**	**n/a**	**277,520**

9.1.3 Opex contributions revenue

Table 9.1.3 Opex contributions revenue – $000

Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
USI load management	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	**(1,000)**
Network recoveries	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	(1,100)	**(11,000)**
Total	**(1,200)**	**(1,200)**	**(1,200)**	**(1,200)**	**(1,200)**	**(1,200)**	**(1,200)**	**(1,200)**	**(1,200)**	**(1,200)**	**(12,000)**
Totals from 1 April 2018 AMP	**(1,600)**	**(1,600)**	**(1,600)**	**(1,600)**	**(1,600)**	**(1,600)**	**(1,600)**	**(1,600)**	**(1,600)**	**n/a**	**(16,300)**

9.1.4 Capex summary

Table 9.1.4 Capex summary – $000

Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Customer connections/ network extensions	11,877	11,849	11,856	11,572	10,755	10,810	10,755	10,755	10,755	10,755	**111,739**
Asset relocations	1,100	4,350	4,100	1,600	1,200	1,200	1,200	1,200	1,200	1,200	**18,350**
HV minor projects	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	**35,000**
LV projects	554	793	1,048	1,082	1,322	1,302	1,577	1,553	1,764	1,736	**12,731**
HV major projects	13,844	15,793	9,044	13,629	10,982	11,077	10,953	10,553	4,328	400	**100,603**
GXP project	-	-	-	17,500	-	-	-	-	-	-	**17,500**
Replacement	31,238	33,221	29,970	31,605	39,351	43,371	42,912	46,630	38,585	36,322	**373,205**
Capitalised internal labour	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	**22,600**
Total	**64,373**	**71,766**	**61,778**	**82,748**	**69,370**	**73,520**	**73,157**	**76,451**	**62,392**	**56,173**	**691,728**
Totals from 1 April 2018 AMP	**60,617**	**57,022**	**60,167**	**60,732**	**57,717**	**68,305**	**68,463**	**70,958**	**54,132**	**n/a**	**619,120**

9.1 Network expenditure forecasts continued

9.1.5 Capital contributions revenue

Table 9.1.5 Capital contributions revenue – $000

Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Asset relocations	(880)	(3,405)	(3,100)	(1,100)	(780)	(690)	(690)	(690)	(690)	(690)	**(12,715)**
Customer connections / network extensions	(983)	(982)	(982)	(942)	(864)	(854)	(854)	(854)	(854)	(854)	**(9,024)**
Major projects	(1,500)	(1,800)	(2,250)	(2,750)	-	(2,250)	-	-	-	-	**(10,550)**
Total	**(3,363)**	**(6,187)**	**(6,332)**	**(4,792)**	**(1,644)**	**(3,794)**	**(1,544)**	**(1,544)**	**(1,544)**	**(1,544)**	**(32,288)**
Totals from 1 April 2018 AMP	**(6,109)**	**(3,428)**	**(4,236)**	**(1,983)**	**(1,663)**	**(1,663)**	**(1,663)**	**(1,663)**	**(1,663)**	**n/a**	**(24,071)**

9.1.6 Capex – customer connections / network extension

Table 9.1.6 Capex customer connections / network extension – $000

Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
General connections	3,705	3,693	3,699	3,693	3,332	3,332	3,332	3,332	3,332	3,332	**34,781**
Large connections	1,258	1,252	1,252	1,252	1,130	1,130	1,130	1,130	1,130	1,130	**11,794**
Subdivisions	3,429	3,414	3,418	3,414	3,080	3,080	3,080	3,080	3,080	3,080	**32,155**
Switchgear purchases	1,297	1,298	1,297	1,242	1,242	1,297	1,242	1,242	1,242	1,242	**12,639**
Transformer purchases	2,189	2,193	2,190	1,971	1,971	1,971	1,971	1,971	1,971	1,971	**20,370**
Total	**11,877**	**11,849**	**11,856**	**11,572**	**10,755**	**10,810**	**10,755**	**10,755**	**10,755**	**10,755**	**111,739**
Totals from 1 April 2018 AMP	**13,597**	**13,297**	**13,247**	**13,247**	**13,247**	**13,247**	**13,247**	**13,247**	**13,247**	**n/a**	**133,832**

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	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
FY20 AMP	1,100	4,350	4,100	1,600	1,200	1,200	1,200	1,200	1,200	1,200	**18,350**
Contributions	(880)	(3,405)	(3,100)	(1,100)	(780)	(690)	(690)	(690)	(690)	(690)	**(12,715)**
Total	**220**	**945**	**1,000**	**500**	**420**	**510**	**510**	**510**	**510**	**510**	**5,635**
Totals from 1 April 2018 AMP	**1,010**	**510**	**590**	**590**	**510**	**510**	**510**	**510**	**510**	**n/a**	**7,880**

9.1 Network expenditure forecasts continued

9.1.8 Capex – HV minor projects

Table 9.1.8 Capex – HV minor projects – $000

	Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
855	Waterloo Rd 11kV feeders	697	-	-	-	-	-	-	-	-	-	**697**
536	Heathcote to Lyttelton 11kV reinforcement	1,200	-	-	-	-	-	-	-	-	-	**1,200**
936	Terrace Rd 11kV overhead reinforcement	359	-	-	-	-	-	-	-	-	-	**359**
932	Pound Rd 11kV reinforcement	92	-	-	-	-	-	-	-	-	-	**92**
933	Lancaster ZS to Milton ZS 11kV tie	274	-	-	-	-	-	-	-	-	-	**274**
922	Milton ZS 11kV alteration	-	366	-	-	-	-	-	-	-	-	**366**
952	Addington 11kV reinforcement	-	249	-	-	-	-	-	-	-	-	**249**
663	Darfield Township reinforcement	-	595	-	-	-	-	-	-	-	-	**595**
920	Southfield Drive cable upgrade	-	371	-	-	-	-	-	-	-	-	**371**
913	Heathcote Lyttelton reconfiguration	-	232	-	-	-	-	-	-	-	-	**232**
Subtotal		2,622	1,813	-	-	-	-	-	-	-	-	**4,435**
Unscheduled HV minor		878	900	900	900	900	900	900	900	900	900	**8,978**
Unidentified HV minor		-	787	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	**21,587**
Total		**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**35,000**
Totals from 1 April 2018 AMP		**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**	**35,000**

For details of individual projects see Section 6.6.7 – HV minor projects.

9.1.9 Capex – LV projects

Table 9.1.9 Capex – LV projects – $000

	Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
884	Low Voltage network monitoring	554	543	798	782	1,022	1,002	1,227	1,203	1,414	1,386	**9,931**
Unidentified LV reinforcement		-	250	250	300	300	300	350	350	350	350	**2.800**
Totals		**554**	**793**	**1,048**	**1,082**	**1,322**	**1,302**	**1,577**	**1,553**	**1,764**	**1,736**	**12,731**
Totals from 1 April 2018 AMP		**275**	**275**	**350**	**450**	**550**	**600**	**600**	**600**	**600**	**n/a**	**4,575**

For details of individual projects see Section 6.6.8 – LV projects.

9.1.10 Capex – major GXP projects

Table 9.1.10 Capex – GXP projects – $000

	Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Norwood GXP - new Region B 220/66kV substation		-	-	-	17,500	-	-	-	-	-	-	**17,500**
Totals		**-**	**-**	**-**	**17,500**	**-**	**-**	**-**	**-**	**-**	**-**	**17,500**
Totals from 1 April 2018 AMP		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**n/a**	**-**

For details of individual projects see Section 6.6.5 – GXP major projects.

9.1.11 Capex – HV major projects

Table 9.1.11 Capex – HV major projects – $000

	Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
881	Hills Rd ZS transformer upgrade	189	-	-	-	-	-	-	-	-	-	**189**
948	Killinchy to Brookside 66kV upgrade	50	-	-	-	-	-	-	-	-	-	**50**
950	Sockburn / Harewood 33kV feeders	548	-	-	-	-	-	-	-	-	-	**548**
938	Papanui ZS 66kV bay	478	-	-	-	-	-	-	-	-	-	**478**
114	Convert Highfield ZS to 66kV	392	-	-	-	-	-	-	-	-	-	**392**
699	Dunsandel ZS upgrade – stage 2	2,130		-	-	-	-	-	-	-	-	**2,130**
929	Marshland 66kV switching station	2,660		-	-	-	-	-	-	-	-	**2,660**
926	Belfast ZS to Marshland 66kV cable	2,600	2,600	-	-	-	-	-	-	-	-	**5,200**
925	Belfast ZS – new 66/11kV substation	4,397	4,397	-	-	-	-	-	-	-	-	**8,794**
924	Belfast ZS 11kV feeder integration	-	417	-	-	-	-	-	-	-	-	**417**
937	McFaddens ZS 66kV bay	-	478		-	-	-	-	-	-	-	**478**
637	Railway Rd 11kV sub (Westland Milk)	-	3,360		-	-	-	-	-	-	-	**3,360**
949	Dunsandel to Killinchy line upgrade	-	30		-	-	-	-	-	-	-	**30**
491	Belfast / McFaddens 66kV cable links	-	4,111	4,111		-	-	-	-	-	-	**8,222**
940	Norwood to Dunsandel 66kV line	-	-	2,820	-	-	-	-	-	-	-	**2,820**
946	Dunsandel ZS 66kV line bay	-	-	493	-	-	-	-	-	-	-	**493**
931	Norwood 66kV switching station	-	-	1,220	1,215	-	-	-	-	-	-	**2,435**
939	Dunsandel ZS 3rd transformer	-	-	-	1,850	-	-	-	-	-	-	**1,850**
941	Norwood to Brookside 66kV line	-	-	-	3,839	-	-	-	-	-	-	**3,839**
945	Papanui 66kV bay for Belfast cable	-	-	-	478	-	-	-	-	-	-	**478**
942	Belfast to Papanui 66kV cable links	-	-	-	5,847	5,847	-	-	-	-	-	**11,694**
894	Springston ZS 2nd 66/11kV Tx	-	-	-	-	1,660	-	-	-	-	-	**1,660**
728	Springston ZS 11kV switchboard ext.	-	-	-	-	580	-	-	-	-	-	**580**
956	Strategic spare 40MVA transformer	-	-	-	-	1,410	-	-	-	-	-	**1,410**
943	Norwood to Highfield 66kV line	-	-	-	-	1,085	-	-	-	-	-	**1,085**
953	Norwood GXP 66kV line bays	-	-	-	-	-	946	-	-	-	-	**946**
954	Highfield ZS 66kV line bay	-	-	-	-	-	478	-	-	-	-	**478**
541	Hawthornden ZS 66kV T-off	-	-	-	-	-	1,616		-	-	-	**1,616**
666	Porters village	-	-	-	-	-	4,600		-	-	-	**4,600**
944	Norwood to Burnham 66kV line	-	-	-	-	-	3,037	-		-	-	**3,037**
639	Burnham ZS - new 66/11kV substation	-	-	-	-	-	-	7,994	-	-	-	**7,994**
919	Halswell ZS 3rd transformer	-	-	-	-	-	-	2,399	-	-	-	**2,399**
934	Walkers Rd 66kV line conversion	-	-	-	-	-	-	160	-	-	-	**160**
723	Milton switchgear for Lancaster cable	-	-	-	-	-	-	-	5,090	-	-	**5,090**
589	Lancaster ZS to Milton ZS 66kV cable	-	-	-	-	-	-	-	5,063	-	-	**5,063**
587	Te Pirita ZS 66kV bays	-	-	-	-	-	-	-	-	939	-	**939**
670	Steeles Rd substation	-	-	-	-	-	-	-	-	2,989	-	**2,989**
955	Strategic land purchase	400	400	400	400	400	400	400	400	400	400	**4,000**
	Total	**13,844**	**15,793**	**9,044**	**13,629**	**10,982**	**11,077**	**10,953**	**10,553**	**4,328**	**400**	**100,603**
	Totals from 1 April 2018 AMP	**6,230**	**4,160**	**5,695**	**7,115**	**0**	**9,558**	**9,616**	**9,361**	**0**	**n/a**	**51,735**

9.1 Network expenditure forecasts continued

9.1.12 Capex – replacement

Table 9.1.12 Capex – replacement – $000

FY20 Replacement Forecast	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Subtransmission overhead lines	1,020	660	660	660	660	3,160	660	3,160	660	660	**11,960**
11kV overhead lines	3,275	2,740	3,355	5,205	5,205	6,440	6,440	8,440	8,535	8,535	**58,170**
400V overhead lines	1,505	1,865	2,225	2,585	2,945	3,305	3,665	4,025	4,385	4,385	**30,890**
Subtransmission underground cables	-	-	-	-	4,115	4,115	4,115	4,115	4,115	4,115	**24,690**
11kV underground cables	100	100	100	100	100	100	100	100	100	100	**1,000**
400V underground cables	7,830	7,830	7,830	7,830	7,830	7,830	7,830	7,830	1,365	330	**64,335**
Communication cables	140	140	140	140	140	140	140	140	140	140	**1,400**
Monitoring	245	185	185	185	185	185	185	185	185	185	**1,910**
Protection	2,555	2,200	2,441	2,085	3,002	3,094	3,156	3,772	3,630	2,792	**28,727**
Communication systems	800	1,005	315	315	315	265	265	265	265	265	**4,075**
Control systems	1,640	1,785	1,440	945	1,190	1,740	1,740	295	385	240	**11,400**
Asset management systems	430	175	40	175	175	40	175	175	40	175	**1,600**
Load management	140	140	1,140	890	190	620	190	190	190	190	**3,880**
Switchgear	7,738	7,976	6,679	7,070	8,379	8,917	10,831	10,518	11,170	10,790	**90,068**
Transformers	2,410	5,410	2,410	2,410	3,910	2,410	2,410	2,410	2,410	2,410	**28,600**
Substations	390	390	390	390	390	390	390	390	390	390	**3,900**
Buildings and Enclosures	620	520	520	520	520	520	520	520	520	520	**5,300**
Grounds	400	100	100	100	100	100	100	100	100	100	**1,300**
Total	**31,238**	**33,221**	**29,970**	**31,605**	**39,351**	**43,371**	**42,912**	**46,630**	**38,585**	**36,322**	**373,205**
Totals from 1 April 2018 AMP	**31,055**	**32,330**	**33,515**	**32,560**	**36,960**	**37,940**	**38,040**	**40,790**	**33,325**	**n/a**	**344,350**

9.1 Network expenditure forecasts continued

9.1.13 Capex – replacement (Commerce Commission's categories)

Table 9.1.13 Capex – replacement (Commerce Commission's categories) – $000

Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Subtransmission	1,020	660	660	660	4,775	7,275	4,775	7,275	4,775	4,775	**36,650**
Zone substations	3,795	6,520	2,460	2,550	5,730	3,130	2,665	1,930	1,915	1,960	**32,655**
Distribution & LV lines	4,090	3,915	4,890	7,100	7,460	9,055	9,415	11,775	12,230	12,230	**82,160**
Distribution & LV cables	430	430	430	430	430	430	430	430	430	430	**4,300**
Distribution substations and transformers	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	**29,550**
Distribution switchgear	5,193	5,406	5,169	5,470	5,099	6,687	9,066	9,488	10,155	9,730	**71,463**
Other network assets	13,755	13,335	13,406	12,440	12,902	13,839	13,606	12,777	6,125	4,242	**116,427**
Total	**31,238**	**33,221**	**29,970**	**31,605**	**39,351**	**43,371**	**42,912**	**46,630**	**38,585**	**36,322**	**373,205**
Totals from 1 April 2018 AMP	**31,055**	**32,330**	**33,515**	**32,560**	**36,960**	**37,940**	**38,040**	**40,790**	**33,325**	**n/a**	**344,350**

9.1.14 Transpower new investment agreement charges

Table 9.1.14 Transpower new investment agreement charges – $000

Project	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Bromley Third 220/66kV Transformer T7	768	768	768	768	768	768	768	768	768	768	**7,680**
Hororata connection for Fonterra dairy factory at Darfield	23	23	23	0	0	0	0	0	0	0	**69**
Islington 66kV metering project for Papanui & Springston	159	159	159	159	159	159	0	0	0	0	**952**
Kimberley 66kV Connection	1,014	1,014	253	0	0	0	0	0	0	0	**2,281**
Norwood GXP	0	0	0	0	1,244	1,244	1,244	1,244	1,244	1,244	**7,466**
Addington & Middleton asset transfer build	90	0	0	0	0	0	0	0	0	0	**90**
Total	**2,053**	**1,963**	**1,203**	**927**	**2,171**	**2,171**	**2,012**	**2,012**	**2,012**	**2,012**	**18,537**
Totals from 1 April 2018 AMP	**2,078**	**1,988**	**1,227**	**951**	**951**	**951**	**792**	**768**	**768**	**n/a**	**12,540**

Assumes 5 year contracts for new agreements
(with the exception of Norwood GXP which uses 30 years).

9.1.15 Transpower connection and interconnection charges

Table 9.1.15 Transpower connection and interconnection charges – $000

Project	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Interconnection	52,532	63,653	64,462	65,534	66,858	67,594	68,754	69,832	70,924	72,032	662,174
Connection	4,330	4,330	4,330	4,330	4,673	4,673	4,673	4,673	4,673	4,673	45,357
Total	**56,862**	**67,982**	**68,792**	**69,864**	**71,531**	**72,268**	**73,427**	**74,505**	**75,597**	**76,705**	**707,531**
Totals from 1 April 2018 AMP	**63,538**	**61,949**	**62,422**	**63,410**	**64,398**	**65,387**	**65,861**	**66,336**	**66,811**	**n/a**	**650,278**

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

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Infrastructure management	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	**14,790**
Network strategy and transformation	161	161	161	161	161	161	161	161	161	161	**1,610**
Network management	3,573	3,666	3,666	3,666	3,666	3,666	3,666	3,666	3,666	3,666	**36,567**
Network operations	7,028	7,050	7,493	7,521	7,549	7,576	7,605	7,632	7,660	7,688	**74,800**
Contact centre	792	792	792	792	792	792	792	792	792	792	**7,920**
Engineering	1,900	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	**19,711**
Works delivery	2,869	2,869	2,869	2,869	2,869	2,869	2,869	2,869	2,869	2,869	**28,690**
Customer connections	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050	**20,500**
Procurement and property services	1,244	1,244	1,244	1,244	1,244	1,244	1,244	1,244	1,244	1,244	**12,440**
Quality, health, safety and environment	649	634	629	634	629	629	629	634	629	629	**6,325**
Asset storage	500	500	500	500	500	500	500	500	500	500	**5,000**
Less capitalised internal labour	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)	**(20,840)**
Total	**20,161**	**20,340**	**20,778**	**20,811**	**20,834**	**20,861**	**20,890**	**20,922**	**20,945**	**20,973**	**207,518**
Totals from 1 April 2018 AMP	**18,213**	**17,950**	**17,950**	**17,957**	**17,950**	**17,950**	**17,957**	**17,873**	**17,873**	**n/a**	**180,027**

9.2.2 Board of directors' fees and expenses

Table 9.2.2 Board of directors' fees and expenses – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Board of directors' fees and expenses	426	426	426	426	426	426	426	426	426	426	**4,260**
Total	**426**	**426**	**426**	**426**	**426**	**426**	**426**	**426**	**426**	**426**	**4,260**
Totals from 1 April 2018 AMP	**396**	**396**	**396**	**396**	**396**	**396**	**396**	**396**	**396**	**396**	**3,960**

9.2 Network expenditure forecasts continued

9.2.3 Business support

Table 9.2.3 Business support – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Senior leadership	5,251	4,501	4,251	4,251	4,251	4,251	4,251	4,251	4,251	4,251	**43,760**
People and strategy	978	919	934	919	934	919	934	919	934	919	**9,309**
Finance	1,323	1,363	1,303	1,383	1,303	1,363	1,323	1,363	1,303	1,393	**13,420**
Information solutions	3,664	3,691	3,699	3,689	3,691	3,699	3,664	3,691	3,699	3,664	**36,851**
Commercial	2,112	2,112	2,112	2,112	2,112	2,112	2,112	2,112	2,112	2,112	**21,120**
Customer and stakeholder	2,616	2,874	2,997	3,062	3,062	3,062	3,062	3,062	3,062	3,062	**29,921**
Governance and risk	255	259	284	274	284	274	284	274	284	274	**2,746**
Insurance	2,065	2,860	3,175	3,243	3,313	3,384	3,457	3,531	3,608	3,686	**32,322**
Corporate properties	914	918	922	926	928	930	932	932	932	932	**9,266**
Vehicles	(990)	(990)	(990)	(990)	(990)	(990)	(990)	(990)	(990)	(990)	**(9,900)**
Less capitalised internal labour	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	(522)	**(5,220)**
Total	**17,666**	**17,985**	**18,165**	**18,347**	**18,366**	**18,482**	**18,507**	**18,623**	**18,673**	**18,781**	**183,595**
Totals from 1 April 2018 AMP	**15,327**	**15,086**	**15,015**	**15,032**	**15,129**	**15,103**	**15,204**	**15,181**	**15,264**	**n/a**	**151,796**

9.2.4 Capex non-network

Table 9.2.4 Capex non-network – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Plant and vehicles	1,317	786	1,216	1,743	1,317	1,169	950	844	1,562	1,721	**12,625**
Information technology	2,287	1,157	1,640	1,007	1,478	1,557	1,043	1,463	1,010	955	**13,597**
Corporate properties	940	430	430	440	430	430	440	430	430	440	**4,840**
Tools and equipment	543	305	305	335	305	305	335	305	305	335	**3,378**
Capitalised internal labour	346	346	346	346	346	346	346	346	346	346	**3,460**
Total	**5,433**	**3,024**	**3,937**	**3,871**	**3,876**	**3,807**	**3,114**	**3,388**	**3,653**	**3,797**	**37,900**
Totals from 1 April 2018 AMP	**3,150**	**2,708**	**3,016**	**3,303**	**2,915**	**2,681**	**2,305**	**2,040**	**3,265**	**n/a**	**29,990**

9.3 Total capex and opex expenditure

Table 9.3.1 Total capex and opex – $000

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	Total
Capital expenditure	69,806	74,790	65,715	86,619	73,246	77,327	76,271	79,839	66,045	59,970	**729,628**
Operational expenditure	66,448	67,036	67,579	67,759	67,731	67,979	68,003	68,166	68,264	68,200	**677,165**
Total	**136,254**	**141,826**	**133,294**	**154,378**	**140,977**	**145,306**	**144,274**	**148,005**	**134,309**	**128,170**	**1,406,793**
Totals from 1 April 2018 AMP	**184,764**	**179,894**	**182,146**	**185,797**	**183,717**	**195,134**	**195,272**	**197,863**	**182,820**	**n/a**	**1,882,406**

9.4 Changes from our previous forecasts

Changes described in these budgets are referenced to our last published AMP which covered the period from 1 April 2018 to 31 March 2028. All forecasts are now in FY20 dollar terms.

9.4.1 Opex – network

Our opex forecasts are generally consistent with last year's forecasts.

9.4.2 Capex – network

Replacement

Our replacement programme is broadly consistent with last year's forecast with the significant exceptions of:

- Underground cables – increase due to labour for supply fuse relocation programme (cost per connection)
- Distribution management system – lifecycle upgrades of systems
- Primary plant – decrease due to refinement of programmes

Connections / extensions

Our customer connection and network extensions cost forecasts are based on our current and forecast business and residential growth forecasts. We expect to connect customers to our network at a lower rate than the previous rate of approximately 3,000 each year to around 2,000 each year.

Asset relocations

Underground conversions are carried out predominantly with road works, at the direction of Selwyn District Council, Christchurch City Council and/or the NZ Transport Agency. Changes this year capture new project identified by road authorities.

HV minor projects

Our HV minor forecasts remain constant at $3.5M per annum.

LV projects

This year we have introduced a new LV monitoring programme to provide greater visibility of the activity on our LV network and prepare for our customers' adoption of new technologies.

Major projects

There's been a significant increase in expenditure due to residential and industrial growth. The new projects are:

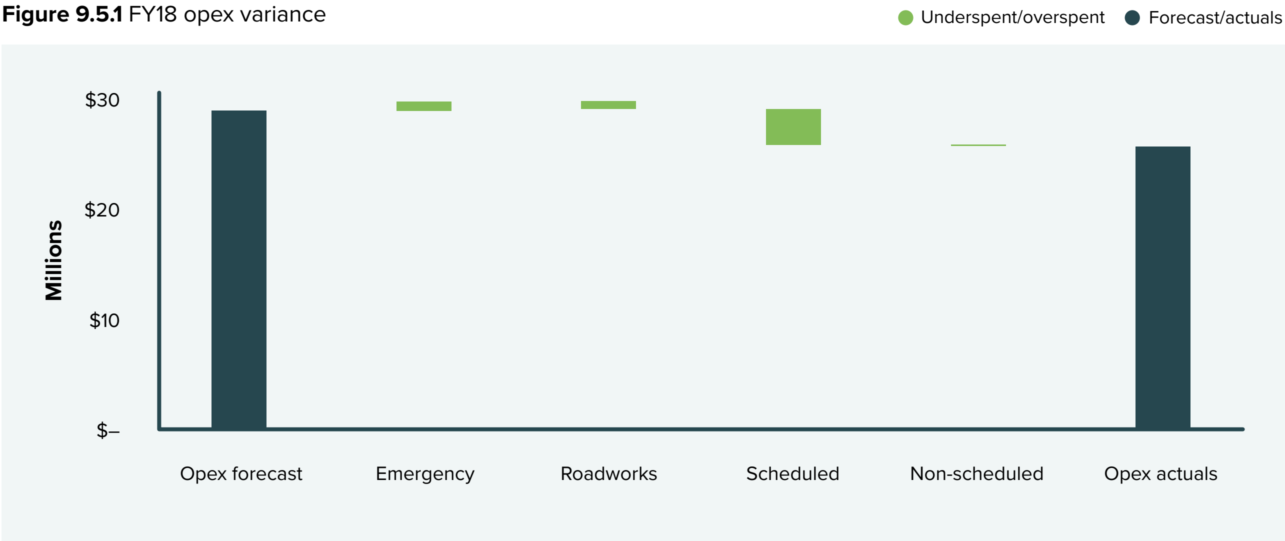
- Papanui ZS 66kV bay planned for FY20 for improved reliability for Waimakariri supply
- Complete conversion of Highfield ZS to 66kV in FY20
- Dunsandel ZS third transformer planned for FY23 for additional capacity
- Strategic spare 40MVA transformer is planned for FY24
- A new 66/11kV Belfast ZS is planned due to customer demand. The new zone substation will require additional work to be carried out within the period of FY20-FY24. Note that this defers the need for Marshland ZS that was forecast for FY23 to beyond FY29. The work under this new project include associated cable works for both 66kV and 11kV
- A new 220/66kV Norwood GXP in Region B is planned to accommodate regional growth. This project is planned for FY22-FY23
- After the completion of Norwood GXP, work to form part of the ring supply to both Highfield ZS and the new Burnham ZS is planned for FY24 – FY25
- Rolleston ZS is planned to be replaced with a new 66/11kV Burnham ZS in FY25-FY26

9.5 Expenditure variation

9.5.1 Network opex variation

Our maintenance costs for FY18 were $25.8m, compared with our budget forecast of $29.0m. The breakdown is shown in Figure 9.5.1.

Figure 9.5.1 FY18 opex variance



The main drivers for the under-expenditure of $3.2m were:

- $0.9m overspent emergencies work budget largely due to higher levels of reactive pole replacement works and higher than expected reactive substation works
- $0.7m underspent roadworks due to roading authorities' requirements. Current trends in work practices means that asset replacement are more likely to facilitate relocation rather than shifting assets, i.e. capital expenditure rather than operational expenditure
- $3.4m underspent in scheduled works largely accounted for by service providers being unable to complete works due to planning/resource issues

9.5.2 Network capex variation

Our network capex actuals for FY18 were $57.7m, compared with our budget forecast of $51.5m. The breakdown is shown in Figure 9.5.2.

Figure 9.5.2 FY18 capex variance

The main driver for the over-expenditure of $6.2m were:

- $3.1m due to higher than expected costs in the customer connections area
- $1.4m due to undergrounding associated with roadworks (NZ Transport Agency driven)
- $1.4m replacement works including the accelerated fuse replacement programme and carry-over overhead works from last financial year

10

Our ability to deliver

Photo: Martin Van Beyere has been a member of Orion's Field Response team for more than 30 years. Based in Lincoln, Martin is the local face of Orion in the Selwyn area, looking after the network from Lincoln and Leeston all the way up to Lake Coleridge and Arthur's Pass. Our Field Response team of 18 provides swift, on the spot investigation of network and customer faults, undertakes emergency repairs and makes the network safe for emergency services.

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 authorises 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 base contract conditions are based on AS/NZS standard conditions for capital, maintenance, and emergency works contracts.

Our Service Providers Specification (NW73.10.15) sets our objectives to use 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 that our overall service provider competence, capability and health and safety objectives are being met.

10.3 Contract delivery

We competitively tender the majority of our 'direct' network opex and capex work to locally based service providers. Now that we have completed our post-quake recovery projects, we forecast that the vast majority of our 'direct' network opex and capex will relate to our ongoing network asset lifecycle activities – that is, the ongoing maintenance and replacement of our network components.

We competitively tender the majority of our 'direct' network opex and capex work to locally based service providers.

Our Procurement and Property Services team prepares, initiates and awards our tenders to service providers.

Our Works Delivery team monitors and assesses each service provider's delivery of each contract or works order, 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 Tenders

We tender all significant contracts as per our procurement policy. Tenders are an appropriate and effective way for service providers to gain a share of our works, and ensures cost competitiveness for our projects. Our wholly owned subsidiary Connetics must competitively tender for contracts with Orion.

We assess tenders from service providers using price – cost and non-price – conformance factors.

Non-price factors include key health and safety, capability, quality, customer service and other factors. We award contracts to service providers following a robust assessment process, which may include clarifications with tenderers on price and non-price factors.

We aim to develop, maintain and grow effective relationships with our service providers to ensure the safe and efficient delivery of contracted works.

We also invite equipment suppliers to tender for major plant items such as transformers, cables and switchgear. Our Contract Delivery Guide sets our objectives and requirements for the efficient contractual delivery of our AMP objectives.

10.3.3 Resourcing

Our ability to deliver our AMP objectives relies on an appropriate level of competent, experienced and skilled resource – both within the Orion team, and via our 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 proactively assess the levels of resources necessary to deliver our objectives. To the extent that is practically and 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 three 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 to invest in their competence and capability. Third, it provides a base level of planned work that can be quickly redirected to areas of greater need following High Impact Low Probability events.

We have a successful history of delivering our network opex and capex via our service providers. We also have a proven ability to successfully deliver on non-direct opex and capex projects – for example, our new corporate office build in FY14 and the new base build for Connetics in FY18.

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

We manage our service provider resources by 'smoothing' our opex and capex works as much as practical to avoid unnecessary resource peaks and troughs.

10.3.4 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
- 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

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.

10.3.5 Delivery

We deliver our programme of scheduled and our emergency works using our contract delivery framework, our service providers, and our in-house team based in our Christchurch office.

Our Infrastructure Management team has the primary responsibility for works delivery and the 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.

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.

We provide a highly responsive service to our customers and community.

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. We also coordinate projects where possible to minimise disruption to customers

Our current approach to contract delivery has proven to be a successful model for Orion for many years, and we believe that it maximises benefits for our customers, our community and our shareholders. 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.

10.3.7 Conclusions on our ability to deliver our forecast work programme

We believe we will be able to carry out the forecast opex and capex programmes detailed in this AMP.

The key reasons we are confident in our ability to deliver this AMP are:

- we have completed our earthquake recovery programme – with this clustered work that was often driven by urgent necessity now behind us, we have returned to our usual more controlled, planned, smoother workflows
- we have restructured our operational teams to gear up to more efficiently deliver our work programme
- 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
- 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 are continuing to invest in the Orion team's capability – for example, we currently employ seven people as part of our engineering development programme
- we have had long-term experience in the effective use of our procurement model and service provider management – proven under testing conditions in the aftermath of the Canterbury earthquakes

We are aware that 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.

We are also considering our options to increase wider industry training and competence development.

Connetics' new base at Waterloo Business Park.

Appendices

Photo: The Southern Alps, viewed from our Kimberley zone substation, Darfield, in the foreground.

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.

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.

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.

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 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 Ability to deliver
6. Lifecycle asset management planning (maintenance and renewal)	7 Managing our assets
	9 Financial forecasting
	10 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															

		Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Technical Specifications	**Document ID**															
Power transformer servicing	NW72.23.25									■						
Mineral insulating oil maintenance	NW72.23.01									■						
Transformer installations (distribution)	NW72.23.16										■					
Transformer maintenance (distribution)	NW72.23.02										■					
Testing and commissioning of secondary equipment	NW72.27.04												■			
Ripple control system details	NW70.26.01													■		
Ripple equipment maintenance	NW72.26.02													■		
SCADA master maintenance	NW72.26.04														■	
SCADA RTU maintenance	NW72.26.05														■	
Kiosk installation	NW72.23.14															■
Graffiti removal	NW72.22.11															■
Equipment Specifications	**Document ID**															
Poles – softwood	NW74.23.06		■	■												
Poles – hardwood	NW74.23.08	■	■	■												
Insulators – high voltage	NW74.23.10		■													
Conductor – overhead lines	NW74.23.17	■	■	■												
Cross-arms	NW74.23.19	■	■	■												
Earthing equipment and application	NW74.23.20		■			■	■	■								
Cable Subtransmission – 33kV	NW74.23.14				■											
Cable Subtransmission – 66kV – 300mm2 Cu XLPE	NW74.23.30				■											
Cable Subtransmission – 66kV – 1,600mm2 Cu XLPE	NW74.23.31				■											
Cable Subtransmission – 66kV – 1,000mm2 Cu XLPE	NW74.23.35				■											
Distribution cable 11kV	NW74.23.04					■										
Distribution cable LV	NW74.23.11						■									
Communication cable	NW74.23.40							■								

		Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Equipment Specifications	**Document ID**															
Switchgear – 400V indoor	NW74.23.23								■							
Circuit breaker – 66kV	NW74.23.25								■							
Circuit breaker – 33kV indoor	NW74.23.28								■							
Major power transformer 7.5/10MVA 66/11kV	NW74.23.07									■						
Voltage regulator 11kV	NW74.23.15									■						
Major power transformer 11.5/23MVA 66/11kV	NW74.23.16									■						
Major power transformer 2.5MVA 33/11kV	NW74.23.22									■						
Major power transformer 20/40MVA 66/11kV	NW74.23.24									■						
Transformers – distribution	NW74.23.05										■					
Ripple control system	NW74.23.09													■		
Kiosk shell – full	NW74.23.01															■
Kiosk shell – half	NW74.23.02															■
Kiosk shell – quarter	NW74.23.03															■
Asset management reports	**Document ID**															
AMR – Protection Systems	NW70.00.22												■			
AMR – Power Transformers	NW70.00.23									■						
AMR – Switchgear HV and LV	NW70.00.24								■							
AMR – Overhead Lines – LV	NW70.00.25			■												
AMR – Overhead Lines – Subtransmission	NW70.00.26	■														
AMR – Overhead Lines – 11kV	NW70.00.27		■													
AMR – Cables – Communication	NW70.00.28							■								
AMR – Cables – LV and Hardware	NW70.00.29						■									
AMR – Cables – 11kV	NW70.00.30					■										
AMR – Cables – 33kV	NW70.00.31				■											
AMR – Cables – 66kV	NW70.00.32				■											
AMR – Circuit Breakers	NW70.00.33								■							

Asset management reports	Document ID	Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
AMR – Communication Systems	NW70.00.34												■	■	■	
AMR – Distribution Management	NW70.00.36														■	
AMR – Load Management	NW70.00.37													■		
AMR – Monitoring	NW70.00.38													■	■	
AMR – Generators	NW70.00.39											■				
AMR – Transformers – Distribution	NW70.00.40										■					
AMR – Voltage Regulators	NW70.00.41									■						
AMR – Property – Corporate	NW70.00.42															■
AMR – Property – Network	NW70.00.43															■
AMR – Substations	NW70.00.44															■
AMR – Vehicles	NW70.00.47															■
AMR – Information Systems (Asset Management)	NW70.00.48												■	■	■	
AMR – Information Systems (Corporate)	NW70.00.49												■	■	■	

Appendix E Specification and standards (network planning)

Design standards	Document ID
Network architecture review: subtransmission	NW70.60.16
Urban 11kV network architecture review	NW70.60.06
Network design overview	NW70.50.05
Project prioritisation and deliverability process	NW70.60.14
Long term load forecasting methodology for subtransmission and zone substation	NW70.60.12
Demand side management stage 1 – issues and opportunities	NW70.60.10
Demand side management stage 2 – potential initiatives	NW70.60.11

Appendix F Disclosure schedules 11-13

This section contains the Information disclosure asset management plan schedules.

Schedule	Schedule name
11a	Report on forecast capital expenditure
11b	Report on forecast operational expenditure
12a	Report on asset condition
12b	Report on forecast capacity
12c	Report on forecast network demand
12d	Report forecast interruptions and duration
13	Report on asset management maturity

Schedule 11a. Report on forecast capital expenditure

Company name: Orion NZ Ltd – AMP planning period: 1 April 2019 – 31 March 2029

		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 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	15,000	12,669	12,996	13,322	13,335	12,745	18,294	13,329	13,620	13,912	14,203
11	System growth	8,813	17,799	20,560	13,956	38,165	16,820	12,118	17,613	17,527	10,402	5,788
12	Asset replacement and renewal	28,661	32,064	35,003	32,439	34,980	44,349	49,903	50,489	55,979	47,484	45,696
13	Asset relocations	8,208	1,288	4,666	4,517	1,929	1,532	1,567	1,602	1,637	1,672	1,707
14	Reliability, safety and environment:											
15	Quality of supply	-	554	558	841	843	1,128	1,131	1,416	1,419	1,704	1,705
16	Legislative and regulatory											
17	Other reliability, safety and environment	325	-	-	-	-	-	-	-	-	-	-
18	**Total reliability, safety and environment**	325	554	558	841	843	1,128	1,131	1,416	1,419	1,704	1,705
19	**Expenditure on network assets**	61,007	64,373	73,783	65,074	89,252	76,575	83,013	84,449	90,182	75,174	69,099
20	Expenditure on non-network assets	4,607	5,433	3,104	4,145	4,174	4,282	4,309	3,601	4,018	4,447	4,739
21	**Expenditure on assets**	65,614	69,806	76,887	69,219	93,426	80,857	87,322	88,050	94,200	79,621	73,838
23	*plus* Cost of financing											
24	*less* Value of capital contributions	6,476	3,363	6,360	6,670	5,168	1,815	4,284	1,783	1,822	1,861	1,900
25	*plus* Value of vested assets											
27	**Capital expenditure forecast**	59,138	66,443	70,527	62,549	88,258	79,042	83,038	86,268	92,379	77,760	71,938
29	Assets commissioned	89,138	89,832	69,506	64,544	81,830	81,347	82,039	85,460	90,851	81,415	73,393
32		$000 (in constant prices)										
33	Consumer connection	15,000	12,669	12,641	12,647	12,363	11,546	16,202	11,546	11,546	11,546	11,546
34	System growth	8,813	17,799	19,998	13,249	35,384	15,237	10,732	15,258	14,858	8,633	4,705
35	Asset replacement and renewal	28,661	32,064	34,047	30,796	32,431	40,177	44,197	43,738	47,456	39,411	37,148
36	Asset relocations	8,208	1,288	4,538	4,288	1,788	1,388	1,388	1,388	1,388	1,388	1,388
37	Reliability, safety and environment:											
38	Quality of supply	-	554	543	798	782	1,022	1,002	1,227	1,203	1,414	1,386
39	Legislative and regulatory											
40	Other reliability, safety and environment	325	-	-	-	-	-					
41	**Total reliability, safety and environment**	325	554	543	798	782	1,022	1,002	1,227	1,203	1,414	1,386
42	**Expenditure on network assets**	61,007	64,373	71,766	61,778	82,748	69,370	73,520	73,157	76,451	62,392	56,173
43	Expenditure on non-network assets	4,607	5,433	3,024	3,937	3,871	3,876	3,807	3,114	3,388	3,653	3,797
44	**Expenditure on assets**	65,614	69,806	74,790	65,715	86,619	73,246	77,327	76,271	79,839	66,045	59,970
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and DSM, reduction of energy losses											
48	Overhead to underground conversion	8,208	1,288	4,538	4,288	1,788	1,388	1,388	1,388	1,388	1,388	1,388
49	Research and development											
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 2019 – 31 March 2029

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 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	355	675	972	1,199	2,092	1,782	2,074	2,365	2,657
55	System growth	-	-	562	707	2,781	1,583	1,386	2,355	2,669	1,769	1,083
56	Asset replacement and renewal	-	-	957	1,643	2,549	4,173	5,706	6,751	8,524	8,074	8,548
57	Asset relocations	-	-	128	229	141	144	179	214	249	284	319
58	Reliability, safety and environment:											
59	Quality of supply	-	-	15	43	61	106	129	189	216	290	319
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
62	**Total reliability, safety and environment**	-	-	15	43	61	106	129	189	216	290	319
63	**Expenditure on network assets**	-	-	2,017	3,296	6,505	7,205	9,492	11,293	13,732	12,782	12,926
64	Expenditure on non-network assets	-	-	80	208	303	406	502	487	630	794	942
65	**Expenditure on assets**	-	-	2,097	3,504	6,808	7,611	9,994	11,780	14,362	13,576	13,868
68	**11a(ii): Consumer Connection**											
69	*Consumer types defined by EDB (see note)*	**$000 (in constant prices)**										
70	General Connections	5,177	4,293	4,282	4,288	4,282	3,921					
71	Large Customers	1,601	1,369	1,363	1,363	1,363	1,241					
72	Subdivisions	4,132	3,501	3,486	3,490	3,486	3,152					
73	Switchgear	1,420	1,317	1,318	1,317	1,261	1,261					
74	Transformers	2,670	2,189	2,193	2,190	1,971	1,971					
76	**Consumer connection expenditure**	15,000	12,669	12,641	12,647	12,363	11,546					
77	*less* Capital contributions funding consumer connections	1,086	983	982	982	942	864					
78	**Consumer connection less capital contributions**	13,914	11,686	11,659	11,665	11,422	10,682					
79	**11a(iii): System Growth**											
80	Subtransmission	18	6,746	7,237	8,662	28,897	6,950					
81	Zone substations	2,659	7,228	5,275	512	2,362	4,162					
82	Distribution and LV lines	179	505	179	179	204	204					
83	Distribution and LV cables	5,764	2,299	5,245	253	278	278					
84	Distribution substations and transformers	12	12	12	12	12	12					
85	Distribution switchgear	51	25	257	25	25	25					
86	Other network assets	131	984	1,793	3,606	3,606	3,606					
87	**System growth expenditure**	8,813	17,799	19,998	13,249	35,384	15,237					
88	*less* Capital contributions funding system growth	-	1,500	1,800	2,250	2,750	-					
89	**System growth less capital contributions**	8,813	16,299	18,198	10,999	32,634	15,237					
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 2019 – 31 March 2029

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
91							
92	For year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
93	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
94	Subtransmission	1,056	1,086	726	726	726	4,841
95	Zone substations	5,022	3,892	6,617	2,557	2,647	5,827
96	Distribution and LV lines	3,615	4,225	4,050	5,025	7,235	7,595
97	Distribution and LV cables	576	586	586	586	586	586
98	Distribution substations and transformers	3,758	3,108	3,108	3,108	3,108	3,108
99	Distribution switchgear	4,515	5,263	5,476	5,239	5,540	5,169
100	Other network assets	10,120	13,905	13,485	13,556	12,590	13,052
101	**Asset replacement and renewal expenditure**	28,661	32,064	34,047	30,796	32,431	40,177
102	*less* Capital contributions funding asset replacement						
103	**Asset replacement and renewal less capital contributions**	28,661	32,064	34,047	30,796	32,431	40,177
107	**11a(v):Asset Relocations**						
108	*Project or programme*	**$000 (in constant prices)**					
109	NZTA	2,552	91	341	341	341	341
110	Christchurch City Council	1,344	544	544	744	744	344
111	Selwyn Disrtict Council	376	331	331	381	381	381
112	Developer / 3rd party	3,305	309	3,309	2,809	309	309
113	Otakaro	631	12	12	12	12	12
115	All other projects or programmes – asset relocations						
116	**Asset relocations expenditure**	8,208	1,288	4,538	4,288	1,788	1,388
117	*less* Capital contributions funding asset relocations	5,390	880	3,405	3,100	1,100	780
118	**Asset relocations less capital contributions**	2,818	408	1,133	1,188	688	608
122	**11a(vi):Quality of Supply**						
123	*Project or programme*	**$000 (in constant prices)**					
124	LV Monitoring	-	554	543	798	782	1,022
125							
126							
127							
128							
130	All other projects or programmes – asset relocations						
131	**Quality of supply expenditure**	-	554	543	798	782	1,022
132	*less* Capital contributions funding quality of supply						
133	**Quality of supply less capital contributions**	-	554	543	798	782	1,022

Schedule 11a. Report on forecast capital expenditure continued

Company name: Orion NZ Ltd – AMP planning period: 1 April 2019 – 31 March 2029

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
135							
136	For year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme*	**$000 (in constant prices)**					
139	[Description of material project or programme]						
140	[Description of material project or programme]						
141	[Description of material project or programme]						
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	Reliability improvement reinforcement projects	325	-	-	-	-	-
154							
155							
159	All other projects or programmes – reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	325	-	-	-	-	-
161	*less* Capital contributions funding reliability, safety						
162	**Other reliability, safety and environment less capital contributions**	325	-	-	-	-	-
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme*	**$000 (in constant prices)**					
169	Plant and vehicles	435	1,317	786	1,216	1,743	1,317
170	Information technology	1,231	2,633	1,503	1,986	1,353	1,824
171	Corporate land and buildings	2,166	940	430	430	440	430
172	Tools and equipment	525	543	305	305	335	305
175	All other projects or programmes – routine expenditure						
176	**Routine expenditure**	4,357	5,433	3,024	3,937	3,871	3,876
177	**Atypical expenditure**						
178	*Project or programme*						
179	Electric vehicle charging stations	250	-	-	-	-	-
180							
185	All other projects – atypical expenditure						
186	**Atypical expenditure**	250	-	-	-	-	-
188	**Expenditure on non-network assets**	4,607	5,433	3,024	3,937	3,871	3,876

Schedule 11b. Report on forecast operational expenditure

Company name: Orion NZ Ltd – AMP planning period: 1 April 2019 – 31 March 2029

		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 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	8,975	8,990	9,229	9,445	9,662	9,878	10,095	10,311	10,528	10,744	10,961
11	Vegetation management	3,560	3,950	4,055	4,150	4,245	4,340	4,435	4,531	4,626	4,721	4,816
12	Routine and corrective maintenance and inspection	13,150	13,140	13,592	13,832	14,111	14,460	14,783	15,065	15,399	15,746	16,057
13	Asset replacement and renewal	3,350	2,115	2,161	2,212	2,262	2,203	2,364	2,414	2,465	2,516	2,262
14	**Network Opex**	29,035	28,195	29,037	29,639	30,281	30,882	31,677	32,322	33,018	33,726	34,095
15	System operations and network support	18,354	20,161	21,077	22,103	22,962	23,728	24,519	25,359	26,177	27,036	27,964
16	Business support	15,455	18,093	19,023	19,765	20,538	21,161	21,910	22,589	23,362	24,108	24,944
17	**Non-network opex**	33,809	38,254	40,100	41,868	43,500	44,889	46,429	47,948	49,539	51,144	52,908
18	**Operational expenditure**	62,844	66,449	69,137	71,507	73,781	75,771	78,106	80,270	82,557	84,870	87,003
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	8,975	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990	8,990
23	Vegetation management	3,560	3,950	3,950	3,950	3,950	3,950	3,950	3,950	3,950	3,950	3,950
24	Routine and corrective maintenance and inspection	13,150	13,140	13,240	13,165	13,130	13,160	13,165	13,135	13,150	13,175	13,225
25	Asset replacement and renewal	3,350	2,115	2,105	2,105	2,105	2,005	2,105	2,105	2,105	2,105	1,855
26	**Network opex**	29,035	28,195	28,285	28,210	28,175	28,105	28,210	28,180	28,195	28,220	28,020
27	System operations and network support	18,354	20,161	20,340	20,778	20,811	20,834	20,861	20,890	20,922	20,945	20,973
28	Business support	15,455	18,093	18,411	18,591	18,773	18,792	18,908	18,933	19,049	19,099	19,207
29	**Non-network opex**	33,809	38,254	38,751	39,369	39,584	39,626	39,769	39,823	39,971	40,044	40,180
30	**Operational expenditure**	62,844	66,449	67,036	67,579	67,759	67,731	67,979	68,003	68,166	68,264	68,200
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	1,654	2,065	2,860	3,175	3,243	3,313	3,384	3,457	3,531	3,608	3,686
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	-	-	239	455	672	888	1,105	1,321	1,538	1,754	1,971
43	Vegetation management	-	-	105	200	295	390	485	581	676	771	866
44	Routine and corrective maintenance and inspection	-	-	352	667	981	1,300	1,618	1,930	2,249	2,571	2,832
45	Asset replacement and renewal	-	-	56	107	157	198	259	309	360	411	407
46	**Network Opex**	-	-	752	1,429	2,106	2,777	3,467	4,142	4,823	5,506	6,075
47	System operations and network support	-	-	737	1,325	2,151	2,894	3,658	4,469	5,255	6,091	6,991
48	Business support	-	-	612	1,174	1,765	2,369	3,002	3,656	4,313	5,009	5,737
49	**Non-network opex**	-	-	1,349	2,499	3,916	5,263	6,660	8,125	9,568	11,100	12,728
50	**Operational expenditure**	-	-	2,101	3,928	6,022	8,040	10,127	12,267	14,391	16,606	18,803

Schedule 12a Report on asset condition

7					Asset condition at start of planning period (percentage of units by grade)							
8												
9	Voltage	Asset category	Asset class	Units	Grade 1 %	Grade 2 %	Grade 3 %	Grade 4 %	Grade 5 %	Grade unknown %	Data accuracy (1–4) %	% of asset to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	0%	0%	10%	37%	53%	-	3	0%
11	All	Overhead Line	Wood poles	No.	1%	1%	27%	12%	59%	-	3	10%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	12%	47%	41%	-	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%	87%	1%	-	3	10%
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	-	-	-	12%	88%	-	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%	7%	58%	33%	-	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.	-	16%	21%	55%	8%	-	3	24%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	44%	9%	47%	-	3	15%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	100%	-	4	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	15%	3%	82%	-	4	15%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	1%	32%	7%	61%	-	4	17%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-

Schedule 12a Report on asset condition continued

					Asset condition at start of planning period (percentage of units by grade)							
36												
37												
38	Voltage	Asset category	Asset class	Units	Grade 1 %	Grade 2 %	Grade 3 %	Grade 4 %	Grade 5 %	Grade unknown %	Data accuracy (1–4) %	% of asset to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3%	5%	13%	29%	50%	-	3	6%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	8%	36%	57%	-	3	7%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	24%	21%	55%	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	0%	0%	100%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	15%	50%	34%	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.	-	-	7%	4%	89%	-	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	0%	9%	42%	16%	33%	-	4	20%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0%	0%	14%	37%	48%	0%	3	4%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) – except RMU	No.	-	52%	48%	-	-	-	4	44%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	0%	21%	23%	56%	-	4	3%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0%	1%	11%	23%	65%	-	3	5%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	19%	23%	58%	-	3	5%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	27%	-	73%	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0%	0%	12%	47%	40%	-	3	2%
55	LV	LV Line	LV OH Conductor	km	-	0%	3%	60%	36%	0%	3	-
56	LV	LV Cable	LV UG Cable	km	-	-	0%	12%	88%	0%	3	-
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	5%
59	All	Protection	Protection relays (electromechanical, solid state)	No.	-	-	20%	23%	57%	-	3	15%
60	All	SCADA and communications	SCADA and comms equipment operating as a single system	Lot	2%	10%	30%	22%	36%	-	3	60%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	100%	-	2	-
62	All	Load Control	Centralised plant	Lot	-	-	16%	75%	9%	-	3	5%
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	28	40	N-1	28	70%	40	57%	No constraint within +5 years	
10	Addington 11kV #2	13	34	N-1	13	38%	34	62%	No constraint within +5 years	
11	Armagh	13	40	N-1	13	32%	40	57%	No constraint within +5 years	Central City Rebuild expected to give large load increase over next few years
12	Barnett Park	9	15	N	9	57%	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	32	60	N-1	32	53%	60	54%	No constraint within +5 years	
14	Dallington	27	40	N-1	27	69%	40	69%	No constraint within +5 years	
15	Fendalton	35	40	N-1	35	88%	40	85%	No constraint within +5 years	
16	Halswell	17	23	N-1	17	75%	23	96%	No constraint within +5 years	
17	Harewood	2	8	N-1	2	25%	8	23%	No constraint within +5 years	
18	Hawthornden	31	40	N-1	31	78%	40	77%	No constraint within +5 years	
19	Heathcote	25	40	N-1	25	62%	40	73%	No constraint within +5 years	
20	Hoon Hay	34	40	N-1	34	86%	40	85%	No constraint within +5 years	
21	Hornby	15	20	N-1	15	73%	20	77%	No constraint within +5 years	
22	Ilam	8	11	N-1	8	72%	11	70%	No constraint within +5 years	
23	Lancaster	21	40	N-1	21	53%	40	53%	No constraint within +5 years	
24	McFaddens	36	40	N-1	36	89%	40	89%	No constraint within +5 years	
25	Middleton	25	40	N-1	25	63%	40	61%	No constraint within +5 years	
26	Milton	32	40	N-1	32	81%	40	83%	No constraint within +5 years	
27	Moffett	14	23	N-1	14	59%	23	77%	No constraint within +5 years	
28	Oxford Tuam	15	40	N-1	15	38%	40	73%	No constraint within +5 years	Central City Rebuild expected to give large load increase over next few years
29	Papanui	40	48	N-1	40	83%	48	119%	No constraint within +5 years	Resolve by transferring load to new Belfast zone substation
30	Prebbleton	6	15	N	6	39%	15	40%	No constraint within +5 years	
31	Rawhiti	29	40	N-1	29	74%	40	74%	No constraint within +5 years	
32	Shands	11	20	N-1	11	54%	20	64%	No constraint within +5 years	
33	Sockburn	27	29	N-1	27	94%	29	96%	No constraint within +5 years	
34	Waimakariri	22	40	N-1	22	56%	40	58%	No constraint within +5 years	
35	Annat	4	-	N	3	-	-	-	No constraint within +5 years	
36	Bankside	6	-	N	4	-	-	-	No constraint within +5 years	
37	Brookside 66kV	9	-	N	7	-	-	-	No constraint within +5 years	
38	Darfield	6	-	N	4	-	-	-	No constraint within +5 years	
39	Diamond **Harbour**	2	-	N	2	-	-	-	No constraint within +5 years	
40	Dunsandel	13	10	N-1	9	133%	23	93%	No constraint within +5 years	Transformer replacement increases capacity
41	Duvauchelles	5	8	N-1	5	68%	8	64%	No constraint within +5 years	
42	Greendale	7	-	N	5	-	-	-	No constraint within +5 years	
43	Highfield	7	-	N	5	-	-	-	No constraint within +5 years	
44	Hills	7	-	N	5	-	-	-	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	Hororata	8	-	N	6	-	-	-	No constraint within +5 years	
46	Killinchy	9	-	N	6	-	-	-	No constraint within +5 years	
47	Kimberley	14	23	N-1	10	60%	23	72%	No constraint within +5 years	
48	Larcomb	12	23	N-1	8	50%	23	78%	No constraint within +5 years	
49	Lincoln	10	10	N-1	7	96%	10	115%	Transformer	Constraint to be resolved by transfers to Springston zone substation
50	Little River	1	-	N	1	-	-	-	No constraint within +5 years	
51	Motukarara	2	8	N-1	2	29%	8	29%	No constraint within +5 years	
52	Rolleston	11	10	N-1	7	106%	10	118%	Transformer	Constraint to be resolved by transfers to Larcomb, Weedons & Highfield
53	Springston 66/11kV	6	-	N	4	-	-	-	No constraint within +5 years	
54	Te Pirita	10	-	N	7	-	-	-	No constraint within +5 years	
55	Weedons	11	23	N-1	7	46%	23	57%	No constraint within +5 years	

Schedule 12c Report on forecast network demand

		Number of connections					
		Current year	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*						
9							
10	For year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
11	*Consumer types defined by EDB**						
12	Streetlighting	11	30	30	30	30	30
13	General	3,428	4,030	4,030	3,930	3,330	2,730
14	Irrigation	17	20	20	20	20	20
15	Major Customer	23	20	20	20	20	20
16	Large Capacity	-	2	-	-	-	-
17	**Connections total**	3,479	4,102	4,100	4,000	3,400	2,800
18							
19	**Distributed generation**						
20	Number of connections	440	460	460	460	460	460
21	Capacity of distributed generation installed in year (MVA)	3	4	4	4	4	4
22	**12c(ii) System Demand**						
23							
24	**Maximum coincident system demand (MW)**						
25	GXP demand	580	627	640	666	678	691
26	*plus* Distributed generation output at HV and above	1	1	1	1	1	1
27	**Maximum coincident system demand**	581	628	641	667	679	692
28	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	581	628	641	667	679	692
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	3,300	3,340	3,380	3,420	3,461	3,503
32	*less* Electricity exports to GXPs	-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation	8	8	9	9	9	10
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**	3,308	3,348	3,388	3,429	3,471	3,513
36	*less* Net transfers to (from) other EDBs at HV and above	3,171	3,209	3,248	3,289	3,328	3,368
37	**Losses**	137	139	141	141	143	145
38							
39	**Load factor**	65%	61%	62%	61%	59%	59%
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 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
10	**SAIDI**						
11	Class B (planned interruptions on the network)	15.5	6.7	6.7	6.7	6.7	6.7
12	Class C (unplanned interruptions on the network)	78.5	77.3	77.3	77.3	77.3	77.3
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.07	0.03	0.03	0.03	0.03	0.03
15	Class C (unplanned interruptions on the network)	1.13	1.06	1.06	1.06	1.06	1.06

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 Asset Management Policy, NW70.00.46, is a Board approved document and was updated as of 30/05/2018. The Asset Management Policy aims to consistently deliver a safe and cost-effective supply of electricity to Orion's customers. The document is available on the Orion website to our wider community (the public). The aims and current status of this Asset Management Strategy (AMS) are discussed at senior management and Board Meetings. Department leaders and staff have presentations on the AMS and how they input into its effectiveness.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	The AMS is reviewed annually and aims to consistently deliver a safe, cost-effective supply of electricity to Orion's customers by using good asset management practices. Through the AMS, Orion are committed to regularly review processes and systems to ensure continual improvement.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.

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	Individual asset class technical strategies exist in the form of 19 Asset Management Reports (AMRs), there are also strategies around supersets of assets e.g. the development of the sub-transmission network. All of these documents are reviewed and updated annually. These reports reflect the agreed lifecycle elements for each asset. They detail why an asset is created, whether to refurbish and when to dispose of it. This lifecycle information then drives the maintenance and replacement forward planning. Orion's asset management database and systems are capable of recording and tracking the lifecycle activities of the assets.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Orion's asset management work plan is documented in broad terms within the AMP. Detailed work plans are documented in the annual work plan and project/program work package documents in NW70.01.17 Annual Work Plan. Asset management plan documents are made available to stakeholders as appropriate to their role within the asset management system, via publishing on a protected area of the Intranet. For low cost high volume items, the plan is expressed in terms of expenditure rather than volume.	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	The Asset Management Plan is published annually and made public on Orion's web site. The work plan is communicated initially in the AMP but it is developed further into a Gantt chart for the major capital projects and maintenance programs, in the form of a 4 page A3 Gantt chart in MS Project which is updated monthly. Contractors have read only access to the Gantt chart. The AMP process is sufficiently mature that stakeholders are aware of the availability of the AMP and may access as required. Detailed work plans are also communicated directly with contractors via the outsourcing process.	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	Overall responsibility of delivery of the AMP is documented to reside with the Network Manager. Asset management tasks are detailed through contract specifications clearly defining requirements for individual work packages. Responsibility for delivery of tasks by service providers is formalised through a commercial contract which is actively managed. This contracting process is documented in NW73.00.04, Contract Delivery Guide. A formal delegation of authority document exists and appears appropriate for execution of the AMP.	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	n 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.

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	Delivery of the asset management work plan is achieved through outsourcing arrangements with service providers. Asset management planning actively considers contractor work levelling in the timing of projects. Publishing long term plans actively signals future workload to the contracting market. See also NW70.01.17 Annual Work Plan. Cost effectiveness is managed by using competitive tendering and ensuring that multiple viable providers are available for all material asset management tasks. Mutual aid agreement with other utilities for emergency response is included in contracts. Forward funding plans are drafted annually, with appropriate cost benefits, risk management and AM Strategy target identified. Routine activities and targeted capital improvement projects are planned and funded to ensure the available contractor resources can complete these activities within the scheduled time frames.	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 has a documented contingency planning processes in place and these processes have been effective as demonstrated by Orion's response to recent events such as storms, and historical earthquake events. Contingency planning includes participation in regional lifelines planning, policy defining emergency roles and responsibilities, and detailed contingency plans for major network scenarios. Orion has load flow contingency plans including switching sheets prepared for total loss of all zone substations. Orion has contingency plan for their resources including internal and external resources. There are multiple contingency planning documents in place for example NW20.40.02 Supply of Emergency Generators and NW20.40.03 Loss of Supply to the CBD, Zone Substations or Grid Exit Points. The resilience of the critical business service delivery has been well planned and resourced. There is adequate staff and contractor resources available to manage all identified events. Forward planning for these events include standby generator sets (both fixed and mobile), a backup control centre at a remote location and a headquarters building is designed to be available throughout most events.	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)?	3.5	The organisation is structured as an asset management organisation. Group roles are defined and overall accountability for the delivery of asset management outcomes rests with the GM – Infrastructure. Where applicable position descriptions include specific Asset Management responsibilities. There is also a matrix of responsibilities for the preparation of the Asset Management Plan. The organisation structure is very clearly designed to ensure AM is a key focus. The Orion focus is on being a high quality "Asset Owner", hence most delivery activities associated with AM is contracted out to local, experienced service providers.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.

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 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	A management review process exists where achievement of asset management activities are routinely monitored and discussed at General Manager level. There is a process for establishing the need for additional FTE employees for internal resourcing, external resourcing is handled by contractors. Resource levelling is managed by the availability of several external contractors who can carry out the same type of work. External contractors are also made aware of the future work program via consultation, the AMP, and workflow reporting so can manage their own resource requirements.	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?	4	An overarching Communications Plan is presently being developed. A range of strategies are employed to communicate the importance of meeting asset management requirements. These range from (i) weekly management meetings attended by all asset management groups, (ii) regular group manager level meetings with service providers, and roadshow presentations to all Orion and service provider scheduled as required. As a component of the Communications Plan, with existing subsidiary communications plans will be included e.g. the "Customer Engagement Framework" which outlines how Orion communicates with its stakeholders and staff alike. Communication about AM at all levels is well embedded and communicated within the organisation.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-about would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	The organisation has not considered the need to put controls in place.	3	Orion is the first respondent to reactive faults. All out-sourced asset management activities are managed through principal - sub-contractor agreements. Formal processes are in place to assure service provider capability and work quality. These align with NW73.00.04, Contract Delivery Guide. Control processes include formal project specifications and documentation, capability audits, process audits and practical completion inspections of works. A Project Manager is accountable for the control of compliant delivery of outsourced activities.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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 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)?	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	The organisation has not considered the need to put controls in place.	"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	Key competencies are documented in job profiles and competence is assessed during bi-annual performance reviews. Training requirements are identified during the performance review process. Orion has an ongoing development programme in place for existing staff and external candidates for key positions within the organisation. These trainees gain work experience in the business, with a view to placement in areas where there are current or forecast skill shortages and/or succession opportunities. Trainees usually complete the programme within four years, and are then placed in permanent roles. Orion has recently completed a restructuring of the AM group. These changes are strengthening the effectiveness within the AM area. Critical roles have effective supportive measures in place, either formal or informal.	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?	3.5	As for question 48 above, core competencies are identified in the job design process and included in job profiles. Competency is regularly reviewed against the requirements of the job profile and training needs identified. Some competencies are held in the PowerOn application which ensures that critical tasks e.g. switching cannot be carried out by persons without the relevant training and competency. Safety training is very focused for all staff and contractors who interact regularly with the assets. Competency recording and refreshers are well documented and managed. Staff or contractors not holding required mandatory competencies (EAC, PHC, Test Permit etc.) are blocked from undertaking higher risk activities. This training and refresher resource is industry leading and it's management is very proactive within industry who focus and drive improvements. Staff and contractors required to undertake switching and higher risk operational functions at the various voltage levels, have specific training and competency certifications.	Widely used AM standards require that organisations undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	Service provider training and competence requirements are controlled through contractual relationships with the service provider and are audited for compliance. Asset management skills and competencies are documented in job profiles and reviewed during the twice yearly performance review process. There is a requirement that Contractors have product vendor training and certification for critical assets e.g. 400V, 11kV, 33kV and 66kV joint kit training and certification. Compliance could be enhanced through the development of a formal skills and competence framework linked to process roles. Focused training is provided to staff and contractors where appropriate. Staff training programs were viewed and cross checked against position descriptions and staff structure.	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	Orion's Communications Plan has been amended and is awaiting final review and sign-off by the GM – Communications. Once it is in place it can be implemented to communicate the key asset management information with internal and external stakeholders. The Communication Plan and processes are now being used and managed by the Communications Manager. Regular meetings and communications are provided to all levels of the organisation and to key stakeholders / contractor leadership. There is a clear focus on AM as required. All field applications (such as GIS) can specifically identify asset items, which then link back to the Basix Asset Database, where specific asset data can be referenced.	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 has in place the key elements of an asset management system and these are documented within the Asset Management Policy/Strategy/Plan/Reports and Network Standards framework. Documentation to comply with a PAS-55 asset management system would be readily achieved by process or system documentation defining how key processes operate and how the existing elements are interlinked. All AM documentation is of a high standard, reviewed and updated regularly. The AMP/Reports and Network standards framework document are very detailed and provide an important information source for all parties involved in AM, both staff and contractors. This level of AM documentation provides extensive information on the specific assets, lifecycle strategies, condition assessments, maintenance requirements, performance, funding and much more. With a little more focus, this documentation could be modified to align to ISO 55001 intent.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	The 2017-2027AMP details all the information and systems required to support Orion's asset management and information systems. The main applications used by Orion to support asset management are also listed. There is an opportunity to develop a formal Asset Information Strategy separately from the AMP. Staff interviewed knew how and where to gain access to the AM information, that their role required them to access. Most had a very specific area of focus, with more senior leaders having a wider focus and/or information access knowledge.	"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	Processes exist to verify the integrity of critical asset information such as network connectivity. Refer appendix C – asset data and Appendix D - specifications and standards) of the AMP records the types of asset data held for each asset class. Updated data generally comes from compliance and routine inspections listed in the asset maintenance plans, as well as specific inspections carried out as required for a particular asset class. There are appropriate levels of data integrity checks via experienced staff, before critical asset data is loaded into AM database. The poles area was specifically looked at and was noted to be exceptionally well managed and of an extremely high quality of accuracy. Asset data and systems are well managed and appropriate data backups are in place.	"The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55)."	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	The AMP describes the overall information architecture and demonstrates alignment with the asset management information needs of the organisation. Asset data users confirm that data is relevant to their needs. A change advisory board periodically evaluates system capability, user needs, and implements changes as required. All AM information and systems appear to be appropriate for the AM requirements of the Orion business. Orion have chosen a "best of breed" approach (as opposed to an integrated system) and is well integrated. There may be some challenges ahead as updates/ upgrades progress, but at present this is well handled. Orion has disaster management plans and these are tested periodically.	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	Section 3 of the AMP details the overall approach to risk, systems utilised, documents and risk management plans. Orion has a number of separate initiatives for the management of risk across the various lifecycle phases. Examples of sub systems include, Vault, CBRM, Public Safety Management System, ICAM and others. While general strategies are documented in the AMP, the formal integration of the various risk management initiatives into an overarching risk management system is not fully complete. The risk management processes for the business are very robust. AM links into these and using these processes to drive their AM activities. "Safety in Design" is an important activity when any changes are made.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/ or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/ or procedure(s) as a result of incident investigation(s). Risk registers and assessments.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	3.5	There is evidence that risks are being identified, and mitigated, and there is evidence that mitigating actions are being linked to resourcing, competencies and training plans. The capabilities available in a) Vault and b) PowerOn are utilised to assist with forecasting for competency and training requirements. Where risks or incident events have identified competencies and/or training improvements are required, these actions are been followed through until completed and signed off as final completed actions by the appropriate senior manager. Training in many cases has been targeted specifically associated with specific assets or asset types.	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 has commissioned a Statutory Compliance Manual outlining the company's legal compliance obligations. This manual is reviewed annually with company lawyers monitoring relevant legislation and regulation for change. Senior managers are required to review and sign a declaration to ensure that obligations pertinent to their area of operations are met. Any potential non-compliances are noted and managed. Compliance is dealt with as a key topic at a number of levels and is integrated in the assessment of risk. Both formal and informal meetings/discussions feed into this process. Key staff have responsibilities to ensure both Orion and it's Board are kept informed, compliant and aware of the ongoing process. Staff have clear PD's and understand their area of responsibilities and authority.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es)).	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Orion has a comprehensive suite of standards and specifications covering all aspects of the asset lifecycle. The process of contracting out the works program is well documented. There are design processes and standards for a 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 19 Asset Management Reports. Some processes and workflows are not formally documented but these are typically around one off designs or projects where it is difficult or not economic to implement standard workflows. Technical standards and specifications are reviewed as alternatives are available.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	Orion's outsourcing processes ensure that only pre-qualified service providers may construct, operate and maintain Orion assets. Contract specifications and standards clearly define the scope of work and place requirements on contractor competency and training. An audit process checks for compliance in terms of contractor capability, work process and finished product. Orion asset management staff or approved auditors witness key operations to ensure compliance with standards. Orion have developed detailed technical specifications and standards for all asset construction or maintenance activities. These documents are part of their outsourcing contract documents and also are used for specific asset procurement contracts.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	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."
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 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.)"
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 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	Orion has identified a suite of service levels and associated performance measures. These service levels, associated measures and targets are documented in the AMP. Orion has implemented a comprehensive methodology Condition Based Risk Management (CBRM) for using asset condition and performance information to evaluate asset health and risk. The methodology has been consistently applied to all key asset classes and is being continually improved. Included in the AMP is this AMMAT review which is externally reviewed on an annual basis. The Orion CBRM process appears to be working well and is providing useful decision making data. Many of the preventative maintenance activities have had a form of Reliability Centred Maintenance (RCM) applied to them, to ensure they meet their AM objectives.	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	Orion has a robust system in place for recording customer outage information and collating network performance statistics. Network outages are routinely reviewed. Minor failures are monitored at a statistical level, with action being taken if frequency increases abnormally, major failures and incidents are investigated on a case by case basis. Procedures for emergency response and repair are clear, with this process being initiated from the control room. A process is in place for investigating equipment failures and non-conformities and recommending actions this includes the formalised ICAM Process. Actions are implemented through normal management channels.	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	As Orion does not have a formally certified PAS-55 asset management system, there is no requirement for formal periodic audits. However, Orion does take actions to periodically review its overall asset management system and capability. The AMMAT process is one of the components of auditing Orion's Asset Management performance and maturity. In this AMMAT review the independence of the process has been further clarified by changing the independent contractor from the one used in previous years. And now further independence with WSP Opus being involved. Contract Managers routinely undertake physical audit of their contractors to ensure they are completing their contracted tasks to the appropriate standards. Compliance audits of contractors are also undertaken annually by Orion staff. Evidence at various levels of operations was examined of the audit functions, including discrepancy reporting which is run weekly and the capture of expenditure outside of authority. These processes operate well, but the control of delegated authority for raising purchase orders could be linked more effectively to prevent occurrence. Independent technical audit was also seen of selected key risk areas, such as poles for overhead lines - the results of these audits was considered satisfactory with only minor improvement suggestions.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.

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	Non conformances or issues are actively managed through normal business activities, roles and responsibilities and the subcontractor management process. The outage report process has been formalised and effectively investigating significant network outages and equipment failure events. The ICAM process is used to investigate if a non-conformance has occurred, then will recommend corrective and preventative actions. All staff and all contractors are made aware that they must report all incidents. These incidents including non and poor-conformances are then reported at the appropriate level. The contractor will often use their own companies reporting / investigation processes, then discuss this with their Orion Contract Manager and are actioned appropriately.	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	Continual improvement is documented as integral to the asset management strategy, and in practice this is achieved through numerous initiatives: The 19 Asset Management Reports, the 11kV Network Architecture Review, Improvements to the Condition Based Risk Management (CBRM) system, the Asset Management system development plan. With Incident Cause Analysis Method (ICAM) tool, this analyses the root cause of asset related incidents and proposes changes that can be adopted to mitigate any failures or incidents. All documents are reviewed and updated at least annually. Improvement opportunities are investigated and future funded as appropriate.	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	Orion obtains information for improvements from a range of sources. External sources of information include: – equipment suppliers – consultants – domestic and international conferences Staff are able to attend relevant industry and supplier technology forums as appropriate. Orion participates in industry groups and conferences to participate in reviewing the introduction and impact of new technologies and practices. These groups include: – The Electricity Engineers' Association (EEA), Asset Management Group and Safety Standards and Procedures Group, The New Zealand Electricity Networks Association (ENA), Smart Technologies Working Group (STWG), and the Electricity Authority (EA) Regulatory Working Group.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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 2019

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 FY19 to FY28 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 FY21, extrapolated by PwC to FY28
- non-network labour – Management's forecast to FY28
- other – NZIER producer price index (PPI) forecasts to FY21, extrapolated by PwC to FY28.

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.

	27th March 2019
Director	Date
	27th March 2019
Director	Date

Orion

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