Orion

Asset Management Plan 2026

Message from the Chair and CEO

Tēnā rā tātou katoa

Central Waitaha Canterbury is one of New Zealand's fastest-growing regions, and the decisions we make about our electricity network over the next 10 years will shape the lives of the people who live and work here for decades to come. This Asset Management Plan (AMP) is our account of what we see ahead and what we intend to do about it.

Our operating context shapes everything in this plan. Many of our network assets are approaching the end of their serviceable lives. Selwyn and Ōtautahi Christchurch are growing at a pace well above the New Zealand average, and the Selwyn District alone is projected to more than double in population by 2055. Canterbury's seismic risk needs no introduction, and severe weather events are increasing in frequency and intensity. The transition customers are making by electrifying their homes and transport or adding solar and batteries, represents exactly the kind of future we want to support. Together, these developments place significant and growing demands on a network that was not built for them.

Our customer engagement over the course of this planning cycle has been extensive. Customers have told us clearly that they value safety, reliability, and resilience. They support investment in the energy transition, and they expect us to invest in the systems and technology that help us operate our network more efficiently and effectively. These expectations are reflected directly in the priorities we have set and the investment trade-offs we have made.

This AMP sets out our response: $1.8 billion in capital expenditure and $1.1 billion in operating expenditure over the next ten years. It has been published alongside our application to the Commerce Commission for a Customised Price-Quality Path (CPP). The CPP is the right mechanism for this moment. It allows us to make the case transparently for an investment uplift that cannot comfortably be accommodated within a Default Price-Quality Path.

We are also clear that a larger investment programme does not mean an unconstrained one. The CPP application process required us to justify our investments in detail and demonstrate it is the minimum necessary to deliver what customers need. We have actively considered and incorporated alternatives to traditional network investment where they offer value for customers; our cost estimates have been independently reviewed, and the substantial majority of our investment has been independently verified. It remains subject to Commerce Commission scrutiny as part of its CPP Determination. We are confident this is a prudent, efficient programme, squarely focused on good outcomes for the communities we operate in.

Delivering our AMP programme will require commitment from our whole organisation, our service delivery partners, and the ongoing support of our community. We are well placed to do this. Our delivery model is proven, our service delivery partners are ready, and we have a clear plan.

We are grateful to everyone who contributed to this plan: our customers and communities who engaged with us, the Board for their challenge and guidance, and the Orion team who built it. This is a plan we are proud to stand behind.

Paul Munro

Board Chair
The Orion Group
June 2026

Nigel Barbour

Group Chief Executive
The Orion Group
June 2026

Executive Summary

1. Executive summary

This Asset Management Plan (AMP) sets out Orion's approach to managing our electricity distribution network across Central Waitaha Canterbury for the 10 years from 1 April 2026 to 31 March 2036 (AMP period). It has been developed and published on 9 June 2026 alongside our application to the Commerce Commission for a Customised Price-Quality Path (CPP) for the five-year period from 1 April 2027 to 31 March 2032 (the CPP period). Box 1.1 explains what a CPP is, and how it relates to this AMP.

This AMP builds on our last full AMP published in 2024, and our AMP update published in 2025. This document meets the requirements of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 and associated Amendment Determinations, as set out in Appendix C — Compliance checklist.

1.1 Our network and the region it serves

Orion owns and operates the electricity distribution infrastructure that connects Central Waitaha Canterbury. We transport electricity from generators and the transmission network to more than 235,000 homes and businesses across 8,000 square kilometres, from Arthur's Pass to the coast and from the Waimakariri to the Rakaia. We are council-owned, accountable to the region we serve, and our purpose is to power a cleaner and brighter future with that community.

Central Waitaha Canterbury is not a typical network environment. Our region takes in one of New Zealand's largest cities, one of its fastest-growing regions, diverse rural areas, and isolated alpine and coastal communities. Urban Ōtautahi Christchurch faces growing pressure from housing intensification on the low voltage network and is expected to grow by around 39% by 2055. The Selwyn District, one of the fastest-growing areas in New Zealand, is projected to more than double in population by 2055, requiring new zone substations and network extensions at pace. Rural areas, irrigation customers, and communities on Banks Peninsula and the Port Hills face different challenges: ageing overhead infrastructure, wildfire and landslip exposure, and the vulnerability of single-supply lines serving dispersed populations. The demands this places on a network not originally built for them are real and increasing.

Alongside growth, what customers are asking the network to do is changing. Customers are electrifying their homes and transport, adding solar panels and batteries, and changing how they use and contribute to the electricity system. Networks like ours are transitioning from one-directional systems that deliver power from large generators to consumers, into two-directional platforms that must accommodate flows in both directions. This creates opportunities to manage peak demand and defer capital-intensive upgrades, but it also adds planning complexity, new operational risks, and upward pressure on operating costs.

Customer and stakeholder expectations around network resilience have risen, and for good reason. Our network faces growing exposure to storms, flooding, wildfire, landslip, and seismic events. These risks are either increasing in frequency or, in the case of earthquakes, ever-present. Fires in the Port Hills in 2017 and 2024 caused network damage and supply interruptions, demonstrating directly what asset vulnerability in these environments means for customers. Cyclone Gabrielle in 2023 demonstrated what sustained high winds and a saturated vegetation environment mean for network damage and restoration times. As a lifeline utility in a high seismic risk environment, the consequences of network failure during a major event are severe and prolonged.

At the same time, much of our network is under pressure from within. Many of our overhead assets were installed in the 1960s and 1970s and are approaching, or have passed, the end of their serviceable lives. Backlogs of asset renewals and maintenance accumulated during, and after, the Canterbury earthquakes recovery, at a time when the region's growth was running ahead of forecasts.

This is not the first time Orion has sought a customised path. Following the 2010-2011 Canterbury earthquakes, we applied for and were granted a CPP from FY15 to FY19, which enabled the network restoration and recovery investment the situation required. When that period ended, we returned to a default path. FY20 to FY25 was a period of stabilisation, and we directed a significant proportion of expenditure toward connecting new customers as the Selwyn District grew rapidly. We deferred some less critical asset renewal work to limit the level of overspend during DPP3.

Box 1.1 What is a Customised Price-quality Path?

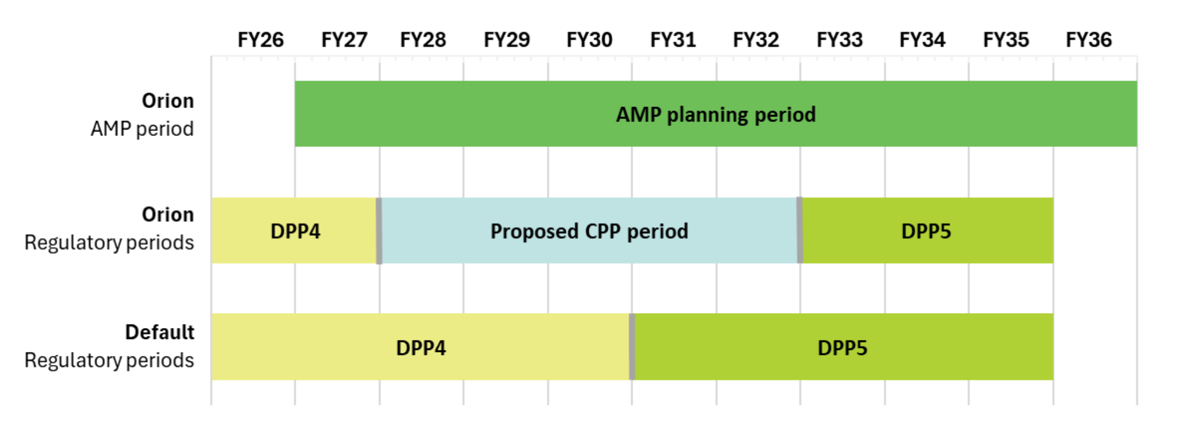
A CPP is a tailored regulatory price-quality path that allows a network business to seek investment allowances beyond those provided under the standard default price-quality path (DPP), where its specific circumstances justify a step change in expenditure.

The business develops an investment proposal through consultation with customers, and it is subject to scrutiny through independent verification, before being submitted to the Commerce Commission for assessment. The Commission determines the applicable price and quality standards for the CPP period following a detailed review of our investment proposal.

This AMP supports our CPP application by providing broader context for the full 10-year asset management planning period, alongside the additional asset management and technical information relevant to the CPP period. The investments, forecasts, and technical analysis in both documents are consistent with each other.

Figure 1.1 shows how our proposed CPP period (FY28–FY32) sits within Orion's 10-year AMP planning horizon and alongside the default regulatory periods.

Figure 1.1 Orion's proposed CPP period (FY28-FY32) alongside default regulatory periods (DPP4 and DPP5)



1.2 Why investment is needed

Our investment programme responds to this context, and is built around five strategic priorities, informed by our regulatory obligations and customer priorities:

- **Maintain safety and reliability** by increasing asset renewal and maintenance activity. We accumulated backlogs of renewal and maintenance during and after the Canterbury earthquakes recovery. Our improved asset condition information also indicates higher renewal requirements for some asset types than previously forecast. Addressing these backlogs and lifting renewal volumes is the largest single component of the investment programme. For example, aged oil-filled 11 kV switchgear at eight zone substation sites cannot be fitted with arc containment, and the probability of failure is increasing. Failure presents an unacceptable safety risk for our people and service delivery partners working on site and would cause suburb-wide outages while switching and repair works are completed. Deferral is not a viable option.
- **Support population and demand growth** by extending and upgrading our network at emerging constraint points. Continued strong growth in Selwyn and Christchurch is expected to drive around 4,400 additional connection requests annually and increase peak demand by 30% over the AMP

period. Investment in new connections, zone substations, and network reinforcement is required to meet this demand while maintaining security of supply.

- **Strengthen resilience** to earthquakes and increasingly severe weather events by renewing high-risk assets and expanding vegetation management. The central Christchurch subtransmission network contains aged 66kV oil-filled cables whose failure in a major seismic event would risk prolonged, widespread outages across the city. Replacing them with modern XLPE cables and reconfiguring the network around them is the most consequential resilience investment in this AMP. Beyond the cable programme, sections of our overhead network on the Port Hills and Banks Peninsula run through terrain with high wildfire exposure, particularly the lines supplying Diamond Harbour, Duvauchelle, Little River, and Akaroa. We are replacing the most exposed poles in these areas as a priority.
- **Prepare for future energy needs** as customers electrify their homes and transport, add solar and batteries, and change how they interact with our network. Initially, our primary focus is improving network visibility, enabling greater use of non-network solutions, and building the operational capability to manage distributed energy resources safely and efficiently. These are foundational investments that will take time to deliver returns but are necessary to avoid the network becoming a constraint on customer choice.
- **Enhance efficiency and capability** by completing the transition to a modern, resilient, and fit-for-purpose information and communication technology environment. Some of this programme, such as our financial management and geospatial systems, has already been delivered. The remaining investment completes the transition of our asset management platforms, which are foundational to the efficiency gains that will reduce costs in the long-term.

Most of these priorities reflect structural characteristics of our network and region that will endure beyond the AMP period. Ageing assets, sustained population growth, seismic and climate-related risk, and the long-term shift in how customers use electricity are not time-bound priorities. We anticipate that preparing for future energy needs will continue to endure as technologies change, and we will need to continue to evolve our network transformation programme later in the AMP period. Enhancing our ICT capability is different in character: it addresses a defined gap, and once the programme is complete the investment profile normalises. The efficiency gains it enables through better asset management decision-making, reduced maintenance costs, and improved labour productivity are expected to flow through progressively in the latter half of the AMP period.

Our assessment is that DPP4 does not provide sufficient revenue to fund this programme. That is why we are seeking a customised path.

1.3 What our customers have told us

Our forecast investment is informed by extensive engagement with customers, conducted through our Powerful Conversations, our Customer Advisory Panel, and dedicated engagement undertaken.

Customers consistently prioritised safety and reliability, resilience, support for the energy transition, and fair and transparent investment decisions. Customers placed different weight on affordability, which we believe reflects the growing recognition of the different impacts to customers from electricity bill increases alongside the broader cost-of-living pressures. Our investment plan seeks to balance the extent and speed at which we deliver our strategic priorities with customer affordability considerations.

Customer engagement and how it informed our investment plan is described in Section 4 – Customers and stakeholders.

1.4 Our investment programme

As depicted in Figures 1.2 and 1.3, we plan to invest approximately $1.8 billion in capital expenditure and approximately $1.1 billion in operational expenditure over the ten-year AMP period, an average of approximately $294 million per year.

In the CPP period (FY28-FY32) capital expenditure (capex) is forecast to be between $166 million and $198 million per year, when renewal, resilience, and growth investment requirements are most concentrated. That investment reduces slightly beyond FY32, returning to approximately $172 million per year, which reflects an ongoing need for sustained investment rather than a return to historical levels.

Similarly, operational expenditure (opex) is forecast at between $109 million and $119 million during the CPP period, before moderating to approximately $117 million per year after the CPP period. This increase reflects the cost of operating and maintaining a larger and more complex network.

Figure 1.2 AMP planning period capex forecast

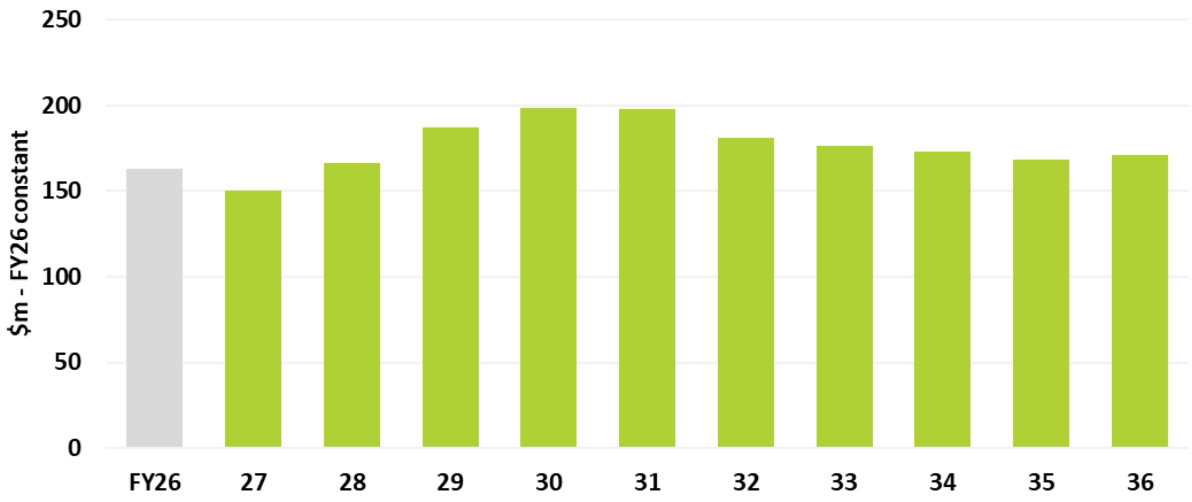
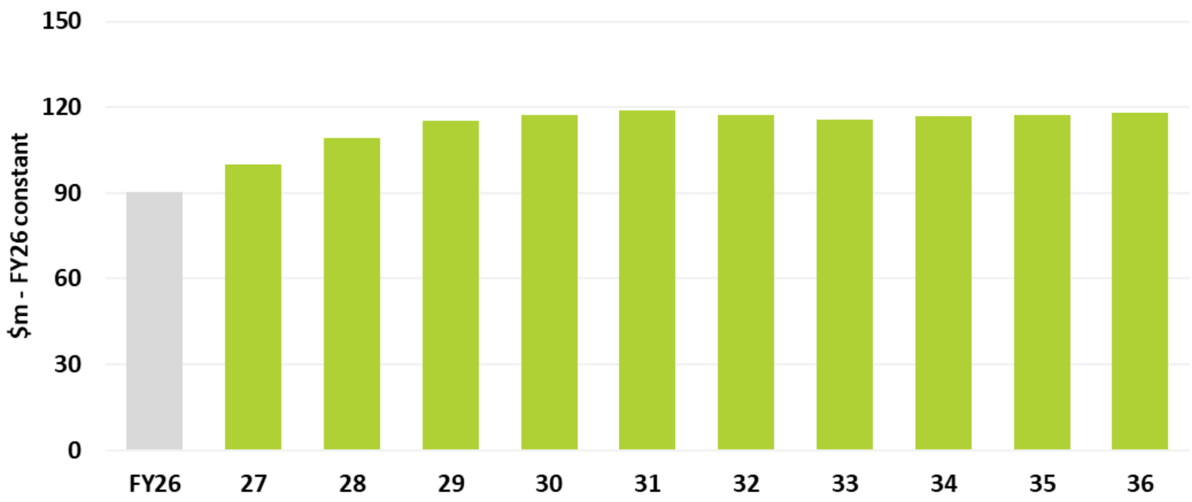


Figure 1.3 AMP planning period opex forecast

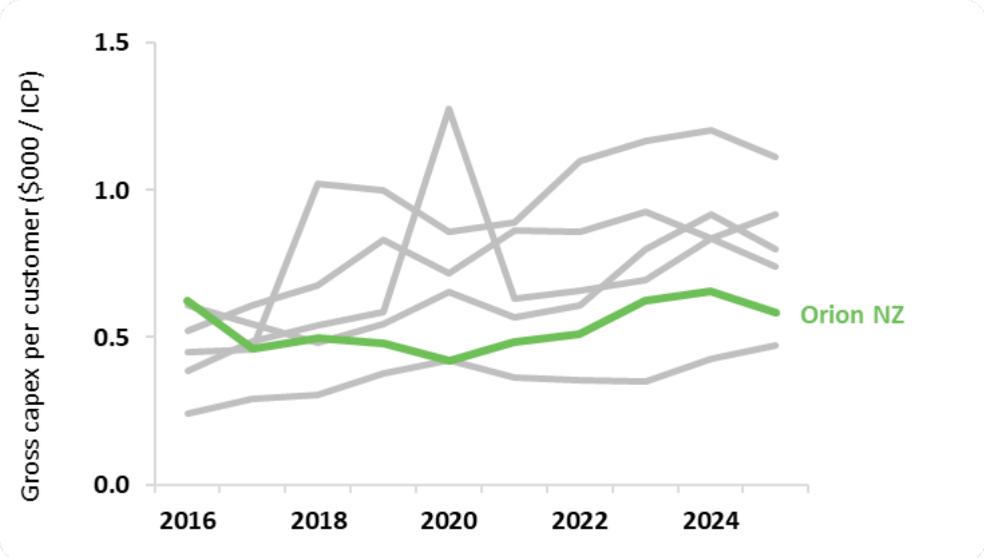


1.4.1 How our historical investment compares

The investment programme in this AMP reflects a genuine catch-up requirement and an acknowledgement of an evolving landscape and associated priorities. While this represents an increase on historic levels, our historical investment has been below average on a per customer basis when compared to the six largest distribution businesses in NZ. Many aspects of our plan are not unique to Orion (e.g. growing need for renewals) and one way to provide context for our level of forecast investment is to compare our historical investment against other large electricity distribution businesses (EDBs).

Figure 1.4 shows gross capital investment per consumer for Orion and the other EDBs over the past decade. Orion has consistently sat at or near the bottom of this range. The same pattern holds when investment is normalised against electricity delivered, line length or customers served. This is not because our network is in better condition than others, but rather it is because we deferred investment during and after the Canterbury earthquake recovery and continued to operate below what our network required during the DPP3 period as growth outpaced our regulated allowances.

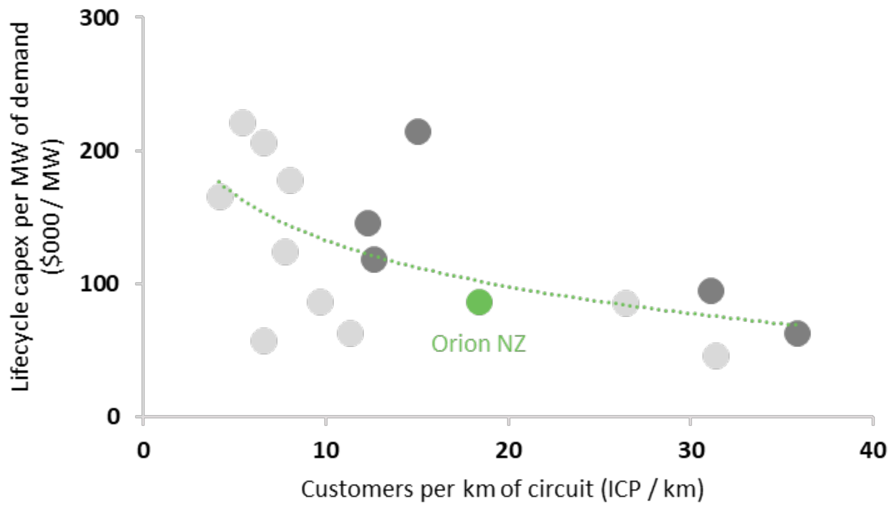
Figure 1.4 Gross capex per customer: Big 6 EDBs (Average 2021 – 2025; FY26 constant)



Source: farrierswier analysis

Figure 1.5 narrows this to lifecycle capex, normalised against customer density. Taking account of customer density enables a comparison across networks with different mixes of urban and rural, and the associated network architecture benefits of supplying denser networks which tend to require less investment per unit of demand. The trend line shows what peers with similar density characteristics have spent. At our customer density, the comparison suggests we have been spending less per MW than peers in equivalent positions.

Figure 1.5 Lifecycle capex per MW by customer density (Average 2021 – 2025; FY26 constant)



These comparisons are not a definitive explanation or justification for investment but provide external context for investment we set out in this AMP. What we are looking to invest through the CPP and 10-year planning period is not a departure from efficient spending, but is an acknowledgement of the need to address a renewals backlog and ongoing aging assets before it builds to the point where we cannot maintain the levels of reliability and safety customers have come to expect.

1.5 Where we are investing

The maps below show the location of major investments across the network. Two different investment drivers are visible.

In Christchurch city, the dominant picture is renewal and resilience: the systematic replacement of the 66 kV oil-filled cable network that runs through the central subtransmission system, alongside zone substation and switchgear renewals at sites across the suburbs. The 66 kV cable replacement programme is the most consequential investment for Ōtautahi Christchurch's resilience to a major earthquake.

Across the wider region, the picture shifts. In Lincoln, Burnham/Rolleston, and Lower Selwyn, the investment is driven by growth, as population expansion pushes ahead of existing network capacity. In rural areas including Banks Peninsula and the mid-Canterbury townships, the focus is on resilience: replacing vulnerable poles, renewing ageing equipment, and improving the network's ability to withstand severe weather events.

Together, the maps reflect a programme responding to genuinely different pressures in different parts of the network that are all pointing toward the need for a comprehensive plan covering multiple strategic priorities (Figures 1.6 and 1.7).

Figure 1.6 Major investments: Ōtautahi Christchurch City

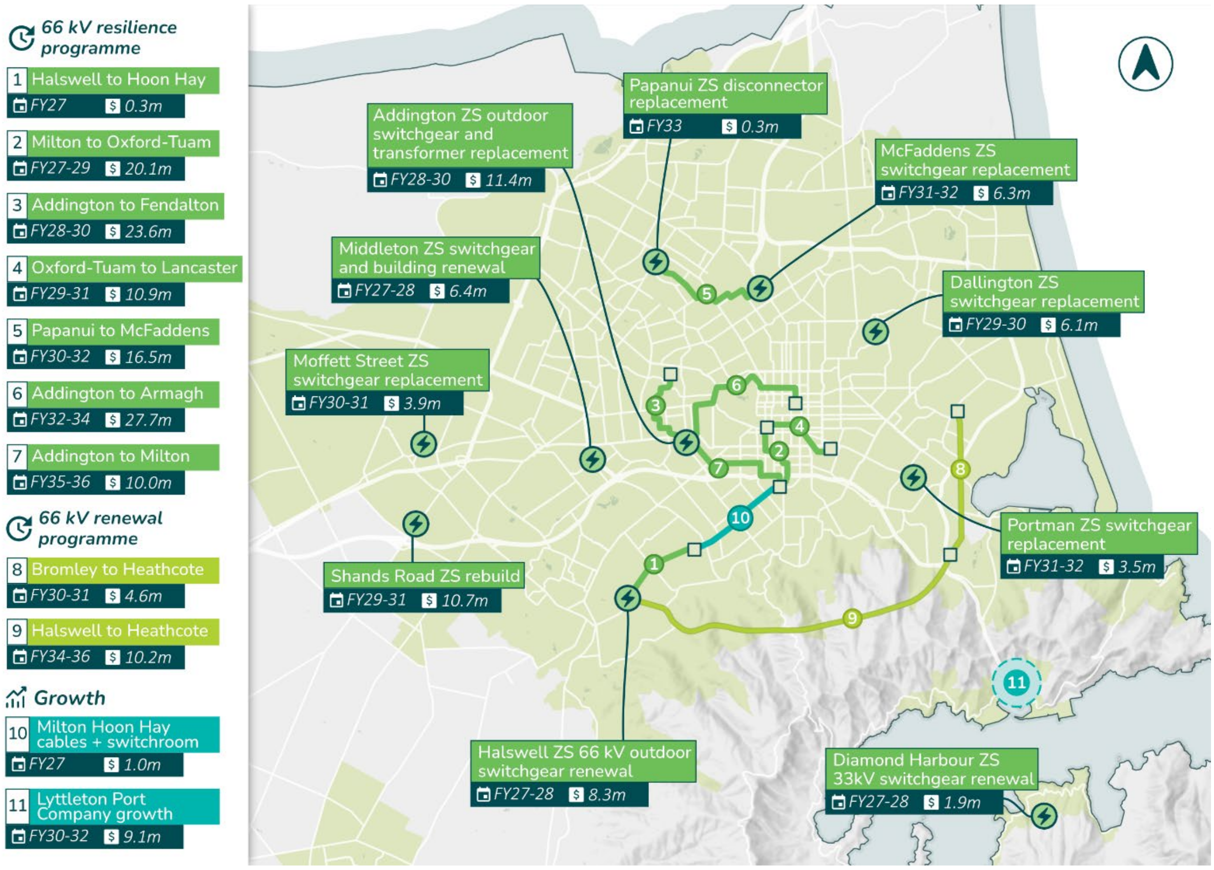
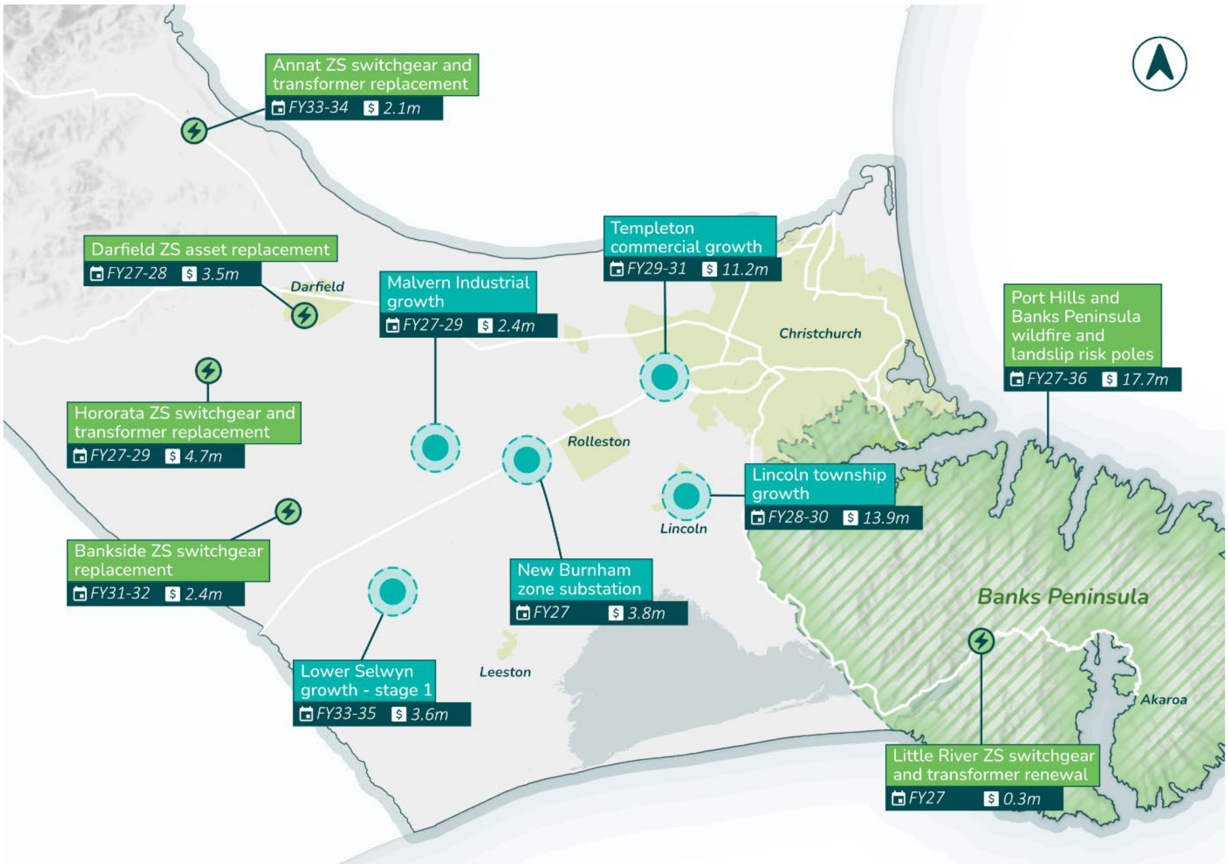


Figure 1.7 Major investments: Regional



1.6 Service measures

We use service measures to assess how well we deliver electricity to customers and meet the standards we have committed to achieving. These measures are gauges of our performance as an electricity distributor and reflect our commitment to providing safe, reliable, and high-quality electricity distribution services to Central Waitaha Canterbury.

Our service measures have been deliberately selected to align to our five strategic priorities.

As outlined above, maintaining reliability of supply is one of our strategic priorities and it is the quality pillar of price-quality regulation. In the years following the 2010-11 Christchurch earthquakes, Orion's reliability performance improved and then stabilised around 2017. Since then, both SAIDI and SAIFI have remained broadly stable, with typical year-to-year variation reflecting weather conditions and operational factors (Figures 1.8 and 1.9).

Figure 1.8 Orion's historical planned and unplanned SAIDI (non-normalised)

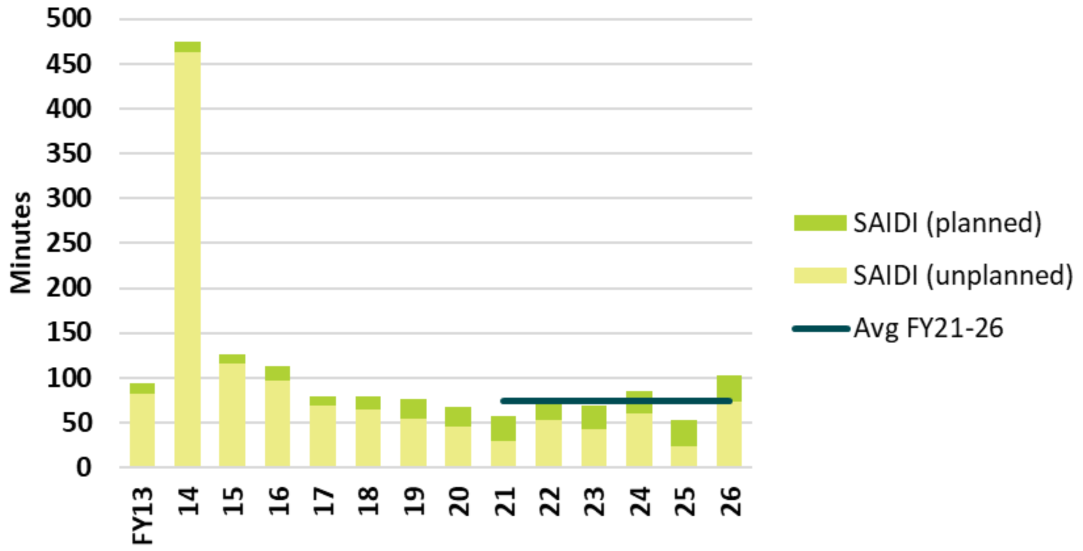
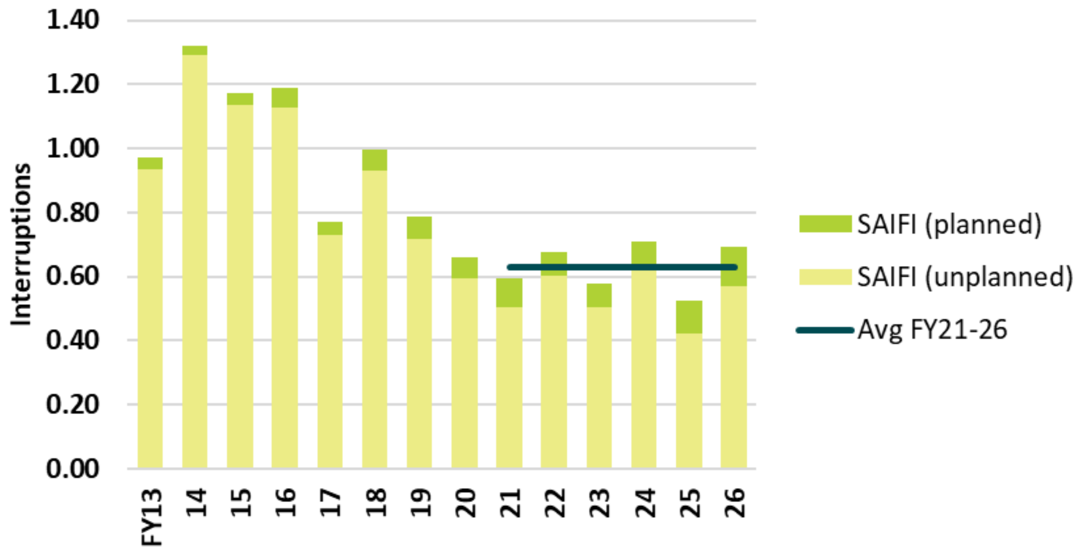


Figure 1.9 Orion's historical planned and unplanned SAIFI performance (non-normalised)



Our service measures include a continuation of SAIDI and SAIFI performance targets (Table 1.1), and new reliability performance measures (Table 1.2). The SAIDI and SAIFI targets are the same as our current DPP4 targets, which reflect customer preferences to maintain current levels of reliability performance. In addition, reliability will be improved in areas where performance is lower than expected, taking account of network architecture and customer preferences.

The Commerce Commission will review and set our Quality Standards as part of the CPP Determination process.

Table 1.1 Reliability performance service measures

Service measure	Annual target to FY36	
	Planned interruptions	Unplanned interruptions
SAIDI (minutes per customer, per year)	≤ 23.83	≤ 63.14
SAIFI (frequency per customer, per year)	≤ 0.074	≤ 0.795
Unplanned interruptions restored within three hours	N/A	≥ 60%

Table 1.2 New reliability performance service measures

Service measure	Initial FY28 target
Percentage of planned interruptions where less than 10 working days' notice is given to electricity retailers	≤ 20%
Number of localised reliability hot spots with an approved corrective action within six months of identification	≥ 3

Our broader services measures include performance targets for safety, power quality, network and operational efficiency and sustainability. See Section 5 – Service measures and performance for a full list and explanation of our service measures.

1.7 A prudent and efficient programme

A larger investment programme does not mean an unconstrained one. For every AMP, we develop our investment forecasts by assessing asset health, network demand, customer needs, and regulatory obligations, and by considering non-network solutions, such as demand-side flexibility and battery storage, where they are viable.

We commissioned independent demand and consumption forecasting from Frontier Economics, had our unit rates reviewed by Ergo Consulting against sector benchmarks, and engaged specialists across expenditure benchmarking, business case development, population forecasting, and financial modelling.

In addition, approximately 75% of our CPP investment plan was independently verified. This was an assessment of whether our programmes are supported by customers, are prudent, and efficient. Where the independent verifier identified areas for refinement, we responded. Further detail on the verification process and our responses is provided in our CPP Main Proposal. Our investment plans will be subject to further scrutiny by the Commerce Commission, including additional customer consultation, as part of the CPP determination process.

We are confident this is the right investment programme for our network and our community.

1.8 How we will deliver

Orion's delivery model combines internal planning and programme management with our service delivery partners, who undertake all network construction, renewal, and maintenance under contract. This is a model that has been tested through the Canterbury earthquakes recovery and the sustained growth surges that followed.

For this AMP, we completed a formal deliverability assessment covering field resource modelling, service delivery partner capacity, including design, construction and supply chain readiness. That assessment confirmed the work programmes are achievable within the planned timeframes. To support efficient delivery, investment is smoothly ramped up over the programme, enabling our service delivery partners to build capability and scale in a controlled manner.

Our delivery model and procurement approach are described in Section 17 – How we deliver.

1.9 Continuous improvement

This AMP has been developed utilising a team with many years of combined asset management experience and with the best asset information and analytics capability available at the time. The asset management environment in which we are operating is evolving with increased complexity and service expectations, and we know that our asset management capability will need to keep pace and stay ahead of change.

Our strategic priorities and investment plan make provision to improve our ICT systems and asset management data quality. These initiatives form the foundations of the next phase in the development of our asset management system, maturity and associated improvement plan.

Our asset management system covers the full lifecycle of our network assets, from strategic planning and investment prioritisation through to operations, maintenance, renewal, and performance monitoring. It is governed by our Asset Management Policy and given strategic direction by our Strategic Asset Management Plan (SAMP), which we published for the first time in July 2025. The SAMP translates our organisational strategy into asset management objectives, decision-making principles, and capability requirements.

In FY26 we undertook an external independent assessment of our asset management maturity using the Asset Management Maturity Assessment Tool (AMMAT), alongside a gap analysis against ISO 55001:2024. We achieved an overall AMMAT score of 2.51[1] (Developing–Competent).

That score reflects where we are in a period of significant change. New systems, a restructured organisation, and new frameworks are in place, but they have not yet completed a full business cycle, and embedding takes time. As it progresses, we expect scores to move toward 3.0–3.5 within 12–18 months.

Our Asset Management Improvement Plan (AMIP) sets out how we will close the remaining gaps, by building end-to-end visibility of our key asset management processes, developing performance measures that tell us whether the system is working effectively, and strengthening how risk-based prioritisation feeds into investment decisions.

The AMIP is described in Section 18 — Asset management improvement.

[1] The highest possible AMMAT score is 4.

Introduction and context

01. Executive summary

02. Introduction
Explains the purpose of this AMP, and its relationship to our CPP Application, and shows this AMP's structure.

03. Who we are
Establishes our organisational context, including ownership and governance structure, service area, network overview, our purpose and strategy, the environment in which we operate, and how we plan for an uncertain future.

04. Customers and stakeholders
Describes who we serve, their interests, how we engage with them, and how their input shapes our asset management decisions.

05. Service levels and performance
Sets out our service level commitments and targets and demonstrates how we measure and track performance.

Strategy and risk

06. Asset management system
Outlines our asset management system, policy, objectives, roles and accountabilities, and our approach to managing assets through their lifecycle.

07. Managing risk
Explains our approach to identifying, assessing, and managing risks to our network and business, and how we build resilience into our operations.

Support

08. People and technology
Explains the workforce and systems that support asset management, including our teams, ICT infrastructure and business systems.

09. Transforming our network
Describes our programme to prepare the network for changing customer needs, including demand-side flexibility, non-network solutions, and new technologies.

Network development

10. Network development approach
Describes our planning approach for network growth and reinforcement, including how we forecast growth drivers, define network constraints and security gaps, complete optioneering and evaluate solution pathways, and prioritise investments.

11. Network demand, distributed generation and constraint forcasts
Sets out our forecasts for network demand, and capacity requirements across our network, including Transpower's grid exit points (GXPs), and our zone substations and distribution network utilisation.

12. Network development programme
Details the major investments we plan to make in our high voltage (HV) and low voltage (LV) networks over the next 10 years to support growth and connect new customers.

Asset portfolio management

13. Operations and maintenance
Explains our approach to operating and maintaining the network to ensure safety, reliability, resilience and optimal asset performance.

14. Asset renewals
Provides detailed information about how we manage each asset class through its lifecycle, including maintenance strategies, and renewal and replacement plans.

15. Managing our non-network assets
Describes our approach to managing buildings, facilities, vehicles, tools and other equipment.

Our investment programme and delivery

16. Our investment programme
Assesses our progress against the 2025 AMP, presents our 10-year capex and opex forecasts, our approaches for cost escalation, cost estimation, efficiencies, investment prioritisation, and any limitations and assumptions on our forecasts.

17. How we deliver
Explains our capability and approach to executing our work programme, including procurement practices, service delivery partner management, and resource planning.

Asset management improvement

18. Asset management improvement
Summarises our recent asset management maturity assessment, recent improvements made, and provides details on our asset management improvement plan.

Appendices

Glossary, information disclosure schedules, compliance checklist, major system growth and asset renewal project details, security of supply guide, network maintenance approach, innovation activities, and year-beginning certification.

2

2. Introduction

This Asset Management Plan (AMP) outlines our approach to managing our electricity distribution network over the next ten years. It is an essential component of our long-term business and network planning and investment framework.

In this AMP we set out our planned investments and expenditure for the 10-year period from 1 April 2026 to 31 March 2036 (AMP period). This includes the years that make up our proposed Customised Price-Quality Path (CPP) from 1 April 2027 to 31 March 2032 (CPP period). All analysis and section details within this AMP are based on Orion's financial year, which ends on 31 March. Accordingly, tables and charts labelled with "FY" refer to the financial year ending 31 March.

The development and publication of this AMP was delayed to June 2026 to ensure alignment with the submission of our CPP Application to the Commerce Commission. This AMP builds on our last full AMP in 2024, reflecting our ongoing asset management improvement programme. Our 2025 AMP was an update only.

This AMP meets the requirements of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 and all associated Amendment Determinations, as set out in *Appendix C – Compliance checklist*.

2.1 AMP relationship to our CPP Application

This AMP is also a core document supporting our application to the Commerce Commission for a CPP covering the five-year CPP period.

The content of this AMP, and the technical analysis that underpins it, are entirely consistent with our CPP Application.

2.2 AMP objectives

The purpose of our AMP is to describe how we intend to manage and invest in our distribution network over the next 10 years, to meet our purpose of "powering a cleaner and brighter future with our community" and ensuring that electricity distribution services continue to be delivered prudently and efficiently. We consider our AMP purpose to be entirely consistent with our overarching corporate purpose.

Our AMP is a core planning document within our business and is developed to execute our Group Strategy and Business Plan as it relates to our distribution network. The Orion Group Business Plan and Statement of Intent (SOI) set our overall strategic direction, which is reflected in our Asset Management Policy and translated into Asset Management Objectives through our Strategic Asset Management Plan.

This AMP then translates those objectives into a 10-year investment programme, supported by a suite of strategies including our Network Development Strategy, Asset Class Strategies, and our Asset Management Improvement Plan. Together, these documents form an integrated planning framework that connects corporate goals to asset management decisions and day-to-day delivery and continuous improvement. Further detail on our asset management system is provided in Section 6.

Operationally, the AMP is a key consideration when developing functional business plans at the business unit level.

The objectives of our AMP are to:

- Describe our organisational context, including who we are, the region we serve, and the strategic direction that shapes how we invest in our network (refer to section 3)
- Explain how we engage with customers and stakeholders and take their views into consideration, along with the service measures we monitor to demonstrate we are delivering on customer

expectations (refer to sections 4 and 5). Our Customer Engagement Report, which forms part of our CPP Application, details our CPP engagement approach and the feedback we received.

- Provide an overview of our asset management system, including our policy, objectives, and roles and accountabilities, including how it is supported by business strategies, and our approach to identifying and managing risk (refer to sections 6 and 7)
- Describe our people, technology, and digital capabilities that underpin our asset management activities, and our programme to transform the network to support a changing energy future (refer to sections 8 and 9)
- Explain how we assess and develop our network to accommodate customer demand using both traditional and non-traditional approaches (refer to sections 10 to 12)
- Detail how we manage and maintain our asset portfolio through their lifecycle, including renewal at end-of-life (refer to sections 13 to 15)
- Explain how our investment plan is forecast, including key assumptions and limitations, and how we will deliver our investment plan over the next 10 years (refer to sections 16 and 17)
- Describe how we evaluate our asset management performance and plan ongoing improvements (refer to section 18).

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

3

3. Who we are

This section describes the context in which we operate and how we shape our asset management decisions through the 10-year period of this AMP.

It also outlines who owns Orion and how we are governed, where we fit within New Zealand's electricity system, together with our strategic direction and the changing environment that drives our investment priorities. It describes our network, its physical extent, the community we serve, and the assets we manage.

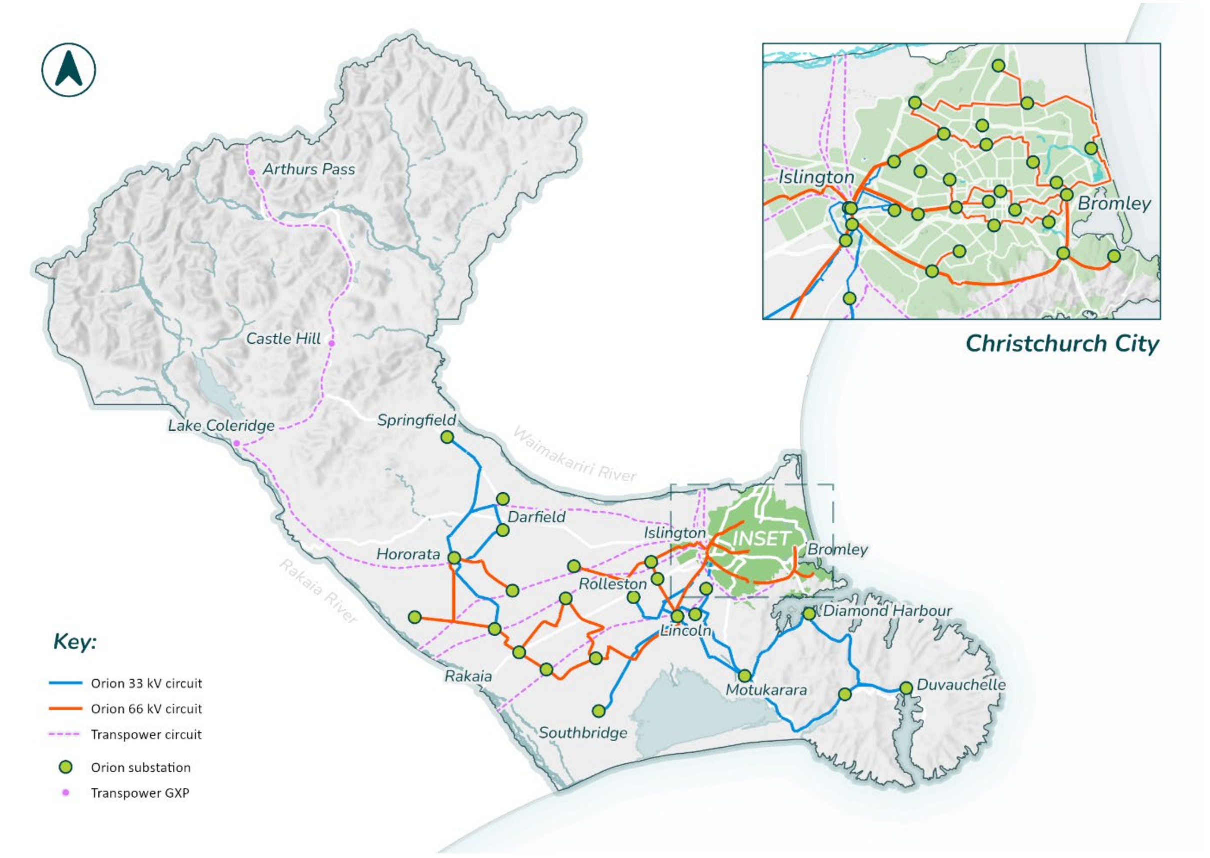
Understanding this context is essential to understanding why we invest where we do, how we balance competing demands, and what our community can expect from us over the next decade. Our aim is to provide customers, and other stakeholders with a clear picture of Orion's operating environment and how we make our strategic and tactical decisions.

3.1 Orion today

From the Rakaia to the Waimakariri, Banks Peninsula to Arthur's Pass, we own and operate the electricity distribution infrastructure in Central Waitaha Canterbury including Ōtautahi Christchurch City and the Selwyn District.

Our network extends over 8,000 square kilometres and delivers electricity to more than 235,000 homes and businesses. We are New Zealand's third largest electricity distribution business (EDB). Our network is both rural and urban, serving diverse communities from the city centre to remote alpine townships, rural areas, and coastal communities across Banks Peninsula.

Figure 3.1 Orion's network area



3.1.1 Ownership and governance

Orion is community-owned by two local councils through the following shareholding structure:

- Christchurch City Council holds an 89.3% shareholding through its investment company Christchurch City Holdings Limited
- Selwyn District Council holds a 10.7% shareholding.

This community ownership means Orion is accountable to the community we serve, through our investments and strategic direction. Our shareholders appoint directors to the Orion Board.

3.1.2 The Orion Group

Orion has a fully owned subsidiary, Connetics Limited (Connetics). Together, Orion and Connetics make up the Orion Group. Connetics is an arms-length business operating as one of our service delivery partners; they also provide services to other EDBs and other third parties outside of our network region.

3.1.3 Our regulatory context

We are subject to price-quality regulation for the delivery of our electricity distribution network services.[2] The Commerce Commission determines the maximum revenue we can recover through our lines charges and the minimum service quality we must provide. Within these parameters, we have flexibility in how we manage our business, and the framework rewards well-managed, efficient delivery. Where investment is managed below or required to exceed regulated allowances, financial incentive mechanisms apply, providing a signal to manage costs effectively while ensuring we continue to invest prudently for the benefit of our customers and the wider Central Waitaha Canterbury community. For the incentive mechanisms to be effective, the regulatory expenditure allowances and quality standards must be set appropriately, and hence the role of CPPs when required.

We have been subject to a default price-quality path (DPP) for the past seven years. Prior to this, we were granted a five-year CPP in 2013, for the period FY15 to FY19, to address the impacts of the 2010-2011 Canterbury earthquakes. At the end of that period, we transitioned back on to a default path.

Our current default path, DPP4, came into effect on 1 April 2025 and applies until 31 March 2030. We expect to transition to a CPP from 1 April 2027 (FY28).

3.2 The Orion Group Strategy

Figure 3.2 illustrates The Orion Group strategy. Further details on each element are set out in the following sub-sections.

Figure 3.2 The Orion Group Strategy

[2] Part 4 of the Commerce Act 1986.

3.2.1 Purpose

Our purpose is "powering a cleaner and brighter future with our community." As a community-owned company, we balance our investment between the need to provide electricity supply today, with preparing our network for tomorrow's energy needs while meeting our regulatory obligations and customer expectations.

3.2.2 Focus areas

The Orion Group Strategy focuses on three areas that drive our strategic priorities:

1. **Our community**: we support the wellbeing and prosperity of the community we serve. We work with our community to build a fit-for-purpose network and explore how non-network solutions, such as battery storage and pricing structures, can incentivise modifications to electricity usage patterns to defer or reduce the need for traditional network investment. By building and designing our network efficiently, we can reduce costs to our community. This focus area ensures that we engage with our community on key projects and mahi (work), understand current and likely future needs, consult on major decisions, and balance investment with affordability.
2. **Safe, reliable, resilient network**: We deliver safe and reliable network performance at the best value for our community. We build network resilience by ensuring we can respond to disruptions and, where possible, avoid them, protecting security of supply and our community from prolonged outages. It includes asset management strategies aligned to stakeholder expectations and risk profiles, and an integrated, digital operating model that supports effective asset management and operational decision-making. We build trust and satisfaction in the reliability of our network through clear communication, quick issue resolution, and services that meet customer needs.
3. **Utilised and accessible network**: We ensure there are no barriers to access and connectivity, creating a responsive energy ecosystem. We promote equity by ensuring all customers, regardless of size or location, can access the network and its opportunities equitably and affordably. A highly utilised network means every substation, line, and cable is operating reliably close to its optimal capacity and is able to service the growth demands of our community. To achieve this, we work with our customers to participate in the energy ecosystem and use non-network solutions where appropriate to manage demand and support the energy transformation.

3.2.3 Key enablers

Three enablers support delivery of our strategic focus:

1. **Our people and partners**: To drive better future outcomes for our customers and community we invest in skilled, responsive teams, both within Orion and across our service delivery partners. By focusing on a skills-first approach driven by digital and data capabilities, promoting inclusivity, and offering a compelling employee value proposition, we aim to secure the talent needed for tomorrow's workforce. We also place a strong focus on building relationships with local stakeholders, including Christchurch City Council, Selwyn District Council, iwi, and sector partners. Our commitment to proactive risk management and a robust safety culture ensures a safe workplace for all, every day.
2. **Funding our future**: we make efficient and prudent investment decisions for the long-term benefit of our community, balancing the need for timely investment with affordability for customers. Our CPP Application reflects this by seeking revenue sufficient to fund required investment while demonstrating that expenditure is prudent and efficient.
3. **Digital and data driven**: we use technology and information to make better decisions about our assets, network operations and management, and future investments. This enabler includes building digital capability that improves efficiency, supports better asset management, and enables us to meet evolving customer expectations. In the long-term our digital investments will

deliver productivity improvements and operating efficiencies that benefit customers through reduced costs.

3.2.4 Investment priorities

Our focus areas inform five investment priorities that will drive the scale and timing of investment over the AMP period, and shaped our CPP Application. The priorities are:

1. **Maintaining the network's safety and reliability levels** by increasing asset renewal and maintenance activities to manage the growing risks of our aging assets.
2. **Supporting strong population and demand growth** in our network area by extending and upgrading the network at emerging constraint points.
3. **Strengthening the network's resilience** to earthquakes and increasingly severe weather events by upgrading high-risk assets and increasing vegetation management.
4. **Preparing for future energy needs** by exploring, piloting and implementing new assets, systems, and processes that build our capability to leverage non-network solutions and support the connection and operation of distributed energy resources (DERs).
5. **Enhancing our ICT capability to increase efficiency** by completing our transition to a modern, resilient, and fit-for-purpose ICT environment to support our asset management activities.

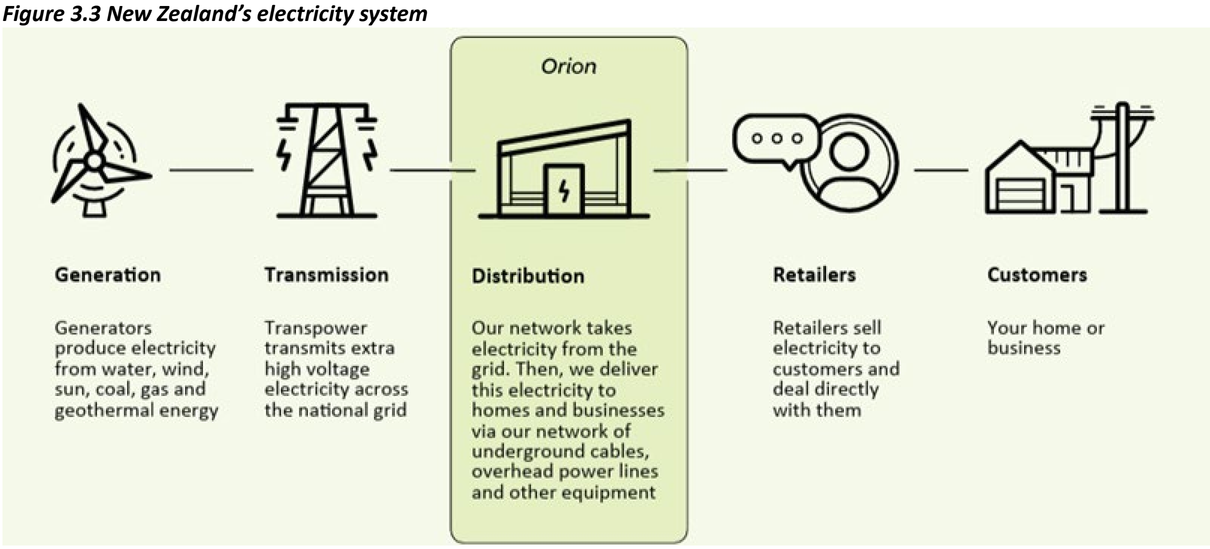
Most of these priorities reflect structural characteristics of our network and region that will endure beyond the CPP period. Ageing assets, sustained population growth, seismic and climate-related risk, and the long-term shift in how customers use electricity are not time-bound priorities. We anticipate that preparing for future energy needs will continue to endure as technologies change and we will need to continue evolve our network transformation programme later in the AMP period. Enhancing our ICT capability is different in character: it addresses a defined gap, and once the programme is complete the investment profile normalises. The efficiency gains it enables through better asset management decision-making, reduced maintenance costs, and improved labour productivity are expected to flow through progressively in the latter half of the AMP period.

Each of these priorities is explained in the context of our operating environment in Section 3.4.

3.3 Our network

New Zealand's energy system comprises different types of businesses working together, including generators, Transpower as the national transmission grid owner, distributors, and retailers. Figure 3.3 shows where we fit in New Zealand's electricity system.

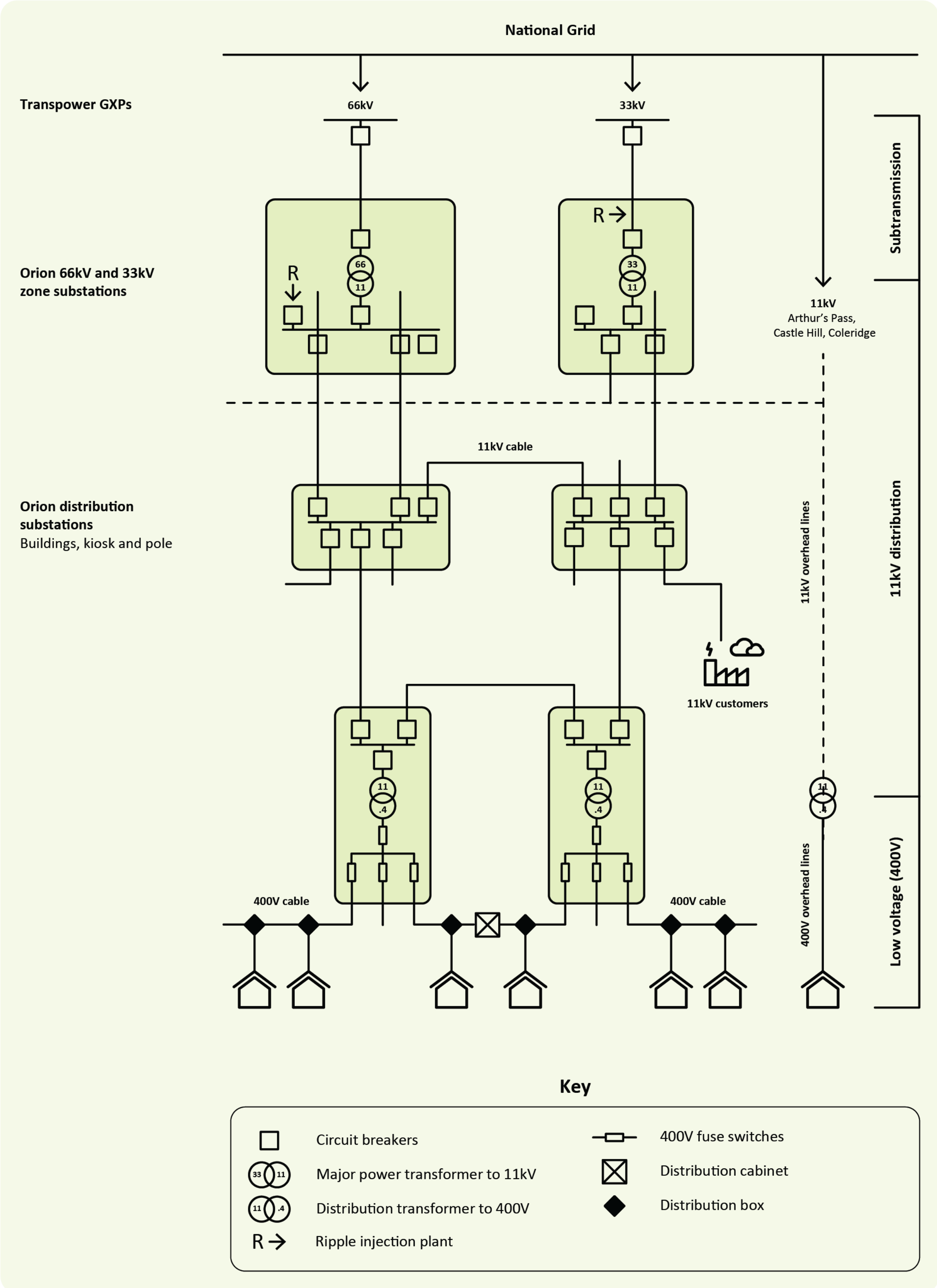
Figure 3.3 New Zealand’s electricity system



3.3.1 Network configuration

Electricity flows from Transpower's grid exit points (GXPs) through our 66 and 33 kV subtransmission network to zone substations, which transform the subtransmission voltage to supply our 11 kV distribution network. The 11 kV distribution network in turn supplies the low voltage network that connects directly to customer premises. Figure 3.4 shows an overview of our network configuration.

Figure 3.4 Network voltage level and asset relationships



Our network is supplied with power from eight GXPs, which are owned by Transpower. The Islington, Bromley, and Norwood GXPs form part of Transpower's South Island grid, interconnecting with major 220 kV circuits from southern power stations. Hororata, Kimberley, and the three smaller GXPs at Coleridge, Arthurs Pass, and Castle Hill connect to the double circuit 66 kV line between Islington and the West Coast with generation injection at Coleridge power station.

Our network has a maximum coincident peak demand of 678MW and delivers 3,519 GWh of electricity to connected customers.[3]

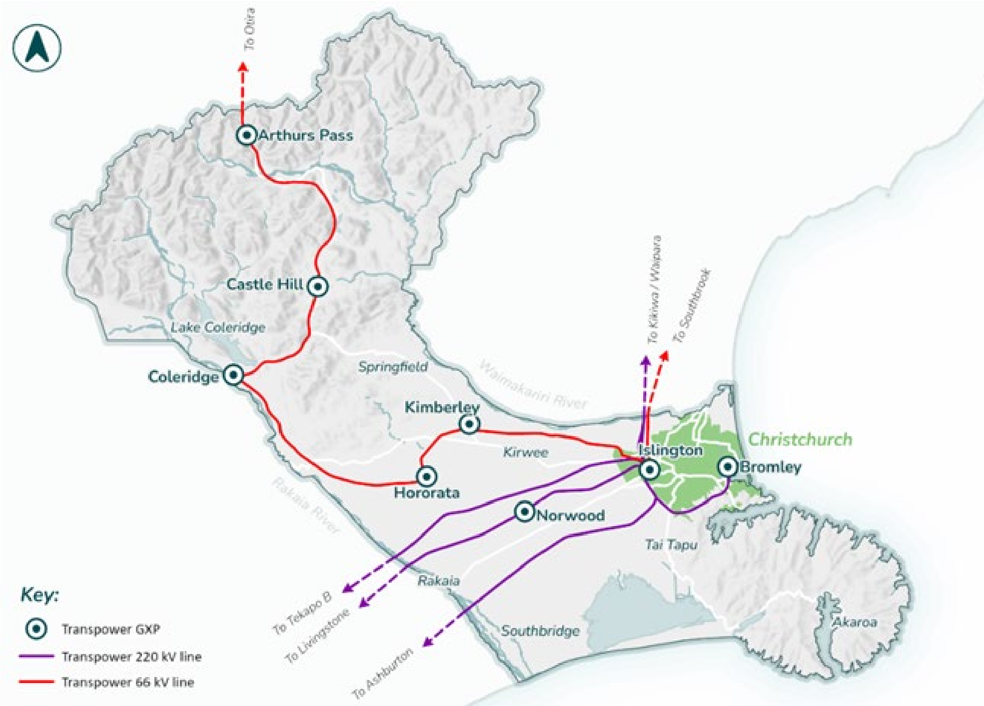
We work with Transpower to plan for GXP connection and for GXP connection asset upgrades to ensure that any capital expenditure at the GXP is cost effective. Security of supply for our subtransmission network is impacted by how Transpower's assets are configured.

Table 3.1 provides details on each GXP, including customer allocation and energy delivered, and Figure 3.5 shows the location of these GXPs and Transpower's transmission infrastructure.

Table 3.1 GXPs and customer allocation

GXP	Voltage connection	Customers (approx. %)	FY25 Energy Delivered (MWh)	Primary areas served
Islington	66 kV and 33 kV	72%	2,563,362	Ōtautahi Christchurch Central City, Lyttelton, Banks Peninsula, Rolleston, Lincoln, Leeston, Southbridge
Bromley	66 kV	25%	693,073	Wider Ōtautahi Christchurch metropolitan area
Norwood	66 kV	1%	173,023	Dunsandel, Killinchy, Brookside
Hororata	66 kV and 33 kV	2%	109,744	Inland Canterbury
Kimberley	66 kV	<1%	84,439	Inland Canterbury
Coleridge, Arthur's Pass, and Castle Hill	11 kV	<1%	4,865	Alpine communities

Figure 3.5 Transpower's transmission infrastructure in our network region.



[3] Orion 2025 Information disclosure, table 9e(ii).

3.3.2 Our network assets

Orion owns all the subtransmission and distribution assets connected to Transpower's GXPs, as well as a number of assets located at those sites, such as communication equipment and protection systems.

Detailed information on asset quantities, age profiles, condition assessments, and renewal strategies for each asset category is provided in Section 14 – Asset renewal.

3.3.3 Distributed generation on our network

Distributed generation refers to a variety of technologies that generate electricity at or near where it will be used, from large diesel backup generators and hydro schemes to small-scale residential solar installations. Unlike large generators, distributed generation connects directly to local networks, like ours, rather than the national grid.

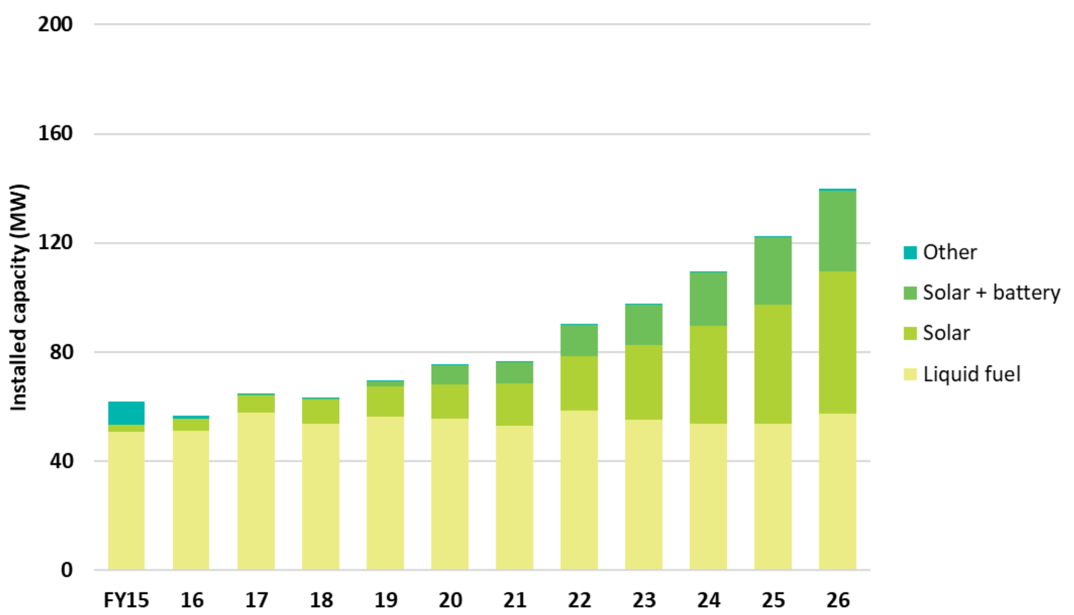
Distributed Energy Resources (DERs) is a broader term that includes distributed generation, as well as energy storage, load management, and energy efficiency solutions. As DER uptake increases, it affects network loading patterns, voltage management, and our planning for future network capacity.

How we plan for and manage DERs, including their impact on network development and demand forecasting, is described in Section 10 – Network development approach and Section 11 – Network demand, distributed generation, and capacity forecasts.

3.3.3.1 Current number of distributed generation connections

As of 31 March 2026, there is approximately 140 MW of distributed generation connected to our network, across approximately 11,500 connections. Figure 3.6 shows the historical growth in customer-owned distributed generation capacity since 2016.[4] The level of small-scale distributed generation continues to grow, driven primarily by residential and commercial solar photovoltaic installations. Refer to Section 11 for a forecast on small-scale distributed generation on our network.

Figure 3.6 Historical distributed generation installations (as of 31 March 2026)[5]



[4] "Other" contains wind and hydro.
[5] Source: Electricity Market Information (EMI), Electricity Authority – www.emi.ea.govt.nz

The following tables show further information in relation to distributed generation connected to our network. Table 3.2 provides a breakdown of installed distributed generation capacity by customer category.

Table 3.2 Installed distribution generation by customer category (as of 31 March 2026)[6]

Customer category	Number of connections
Residential	10,388
Business (including small to medium enterprises)	486
Commercial	396
Industrial	345
Total	**11,615**

Table 3.3 lists the utility-scale generators, i.e. any generation greater than or equal to 1 MW, which are connected to our network.

Table 3.3 Utility-scale distributed generation 1 MW or greater by GXP (as of 31 March 2026)

GXP	Total generation capacity (MW)	Number of generators	Voltage	Generator type
Bromley	2.7	2	11 kV	Diesel back-up
Islington 33 kV	4.6	3	11 kV	Diesel back-up
Islington 66 kV	6.7	6	11 kV	Diesel back-up
Total	**14**	**11**		

3.3.3.2 Distributed generation connection pipeline

Table 3.4 shows the current pipeline of utility-scale distributed generation connection applications by GXP. This pipeline provides an indication of future generation capacity that may connect to our network, subject to application approval and project completion.

Table 3.4 Utility-scale distributed generation connection pipeline (as of 31 March 2026)

GXP	Generation capacity (MW)	Number of projects	Fuel type	Expected commissioning[7]
Islington	150	1	Solar	2026 – 2027
Norwood	306	4	Solar / Battery	2027 – 2030
Hororata	8	1	Solar	2027
Kimberly	212	2	Solar / Battery	2028 – 2030
Total	**676**	**8**		

Notes:

- *Pipeline projects are at various stages of consent and approval. Not all projects may proceed to connection.*
- *Capacity figures represent expected generation at the connection point.*

[6] Ibid

[7] First winter after project is commissioned.

3.3.4 Major customers by load size

We have 404 customers who we categorise as major customers, as defined in our Pricing Policy.[8] We discuss their security and reliability of supply requirements on an individual basis, in relation to our normal network service levels, at the time of connection or upgrade.

Our delivery pricing structure for major customers gives them the ability to reduce costs by managing their load during control periods[9] from 1 May to 31 August. Table 3.5 lists the nominated maximum demand, industries and sectors of our major customers.

Table 3.5 Major customers by nominated maximum demand and industry/sector

Load	Industry / sector	Number	Notes
< 2 MVA	Various	363	Includes heavy manufacturing, hotels, water and wastewater pumping stations, prisons, data centres, sport and recreation, retail and businesses.
≥ 2 MVA	Food processing and other agriculture	19	
	Tertiary education	2	
	Hospital	5	As part of our obligations under the Civil Defence Emergency Management Act 2002, we have ongoing discussions with life-line services to ensure appropriate levels of service are provided for in our future planning.
	Airport / seaport	2	
	Manufacturing	4	
	Various	9	Includes other public services, retailing, shopping malls, utilities, transport and construction.

3.4 Our operating environment and investment priorities

This section explains how each of the five investment priorities set out in Section 3.2.4 relates to our operating environment.

3.4.1 Maintaining the network's safety and reliability levels

A substantial portion of our network was built in the 1960s and 1970s. Many of these assets are at, or are approaching, the end of their serviceable life and will require replacement within the AMP period.

As network assets age, and their condition declines, both the likelihood of failure and the need for corrective and reactive maintenance increases. We aim to proactively renew and/or maintain assets before these risks and costs escalate, in line with good asset management practice.

When we manage assets proactively, we can plan work efficiently, minimise customer disruption, and avoid the higher costs of reactive maintenance and replacement.

Over the coming years, we propose to proactively renew and/or maintain a larger proportion of assets than we have historically.

3.4.1.1 Past deferrals and accumulated backlog

The 2010-11 Canterbury earthquakes have had a lasting impact on our historical expenditure. Significant investment was required to restore the network and support recovery, enabled by our FY15-19 CPP. To manage workforce capacity and price impacts during this period, we deferred some necessary but non-critical expenditure, including certain asset renewal and maintenance activities. In the subsequent

[8] https://www.oriongroup.co.nz/assets/Our-story/Pricing/Orion-pricing-policy-1-April-2026.pdf

[9] Further information on our control periods may be found in our Major Customer Pricing Summary and FAQ, available on our website: https://www.oriongroup.co.nz/our-story/pricing.

period (FY20-25), we prioritised investment in system growth and new connections to accommodate stronger-than-forecast population and demand growth, resulting in further deferral of renewal activity.

While prudent in the circumstances, these decisions have resulted in a backlog of required asset renewal. Some asset fleets, such as overhead distribution conductors, have also historically been managed on a largely reactive basis, with no established proactive renewals programmes, compounding the backlog. Together, these factors have elevated the risk of defects and faults leading to reliability and safety incidents. We propose to resume these programmes and address the accumulated backlog during the CPP period.

3.4.1.2 Better information and improved asset management tools

We have recently implemented enhanced asset inspection methods, forecasting techniques, and decision-support tools. This work indicates that certain assets and fleets are at increasing risk of failure as they age. The improved information and analytics have been used to develop our investment forecasts over the AMP period.

We recently introduced enhanced inspection standards and, during the CPP period, propose to further expand the information we collect for some asset classes to support improved analytics and decision-making. This requires that we increase our preventive maintenance activities.

An increase in inspections and data analysis will support more targeted and efficient renewal programmes. When we have more complete condition data, we can renew assets proactively before they fail, avoiding the safety risks, service disruption, and higher costs associated with reactive replacement. Without this investment, we risk managing more of our network reactively, with the associated inefficiencies.

3.4.1.3 Emerging renewals needs.

We expect to assume ownership of telecommunications poles during the AMP period. These poles support some of our overhead network but are no longer required for telecommunications services. Based on initial transfers and detailed inspections, a significant proportion appear to be in poor condition and are likely to require renewal, though the full extent will only become clear as transfers progress and inspections are completed. This transfer of ownership will also move responsibility for inspection and ongoing maintenance to us.

We also intend to initiate renewal programmes for asset types, such as steel structures, and to begin proactively replacing assets, such as crossarms. In addition, we have begun to replace certain poles that are vulnerable to wildfire risk and will continue to do so over the AMP period.

3.4.2 Supporting strong population and demand growth

Central Waitaha Canterbury is experiencing exceptional growth. Between 2018 and 2023, the Selwyn District's population grew by 29%, compared to an average nationwide growth of 6.3%. Ōtautahi Christchurch City's population also grew steadily, coupled with changes in planning rules that encourage housing intensification.

Independent population forecasts by Geografia, commissioned by Orion, indicate this strong growth will continue. The Selwyn District’s population is projected to increase from about 87,000 in 2025 to 210,000 by 2055, an increase of approximately 141%. Ōtautahi Christchurch City's population is projected to increase from about 419,000 in 2025 to 582,000 by 2055, an increase of approximately 39%.

This population growth drives our forecast network demand, resulting in around 4,400 new connections per annum to our network, once disconnections and connection alterations are factored in. These connections include new homes and businesses in subdivisions on the fringes of fast-growing towns like Lincoln and Rolleston, and infill development in Ōtautahi Christchurch City. Several large industrial customers are also expected to decarbonise their operations, requiring connection upgrades.

As a result of this growth, alongside electrification of transport and process heat, we expect maximum peak demand on our network will increase by 31% over 10 years, up from 718 MW in FY27 to 939 MW by FY36.

Customers expect the network to have sufficient capacity to support forecast growth, while maintaining current levels of reliability and security of supply. Meeting this expectation will require ongoing investment in customer connections and system growth. This investment includes building new zone substations, extending subtransmission and distribution networks, and undertaking significant reinforcement of the low voltage network. We will continue to explore non-network solutions that reduce peak demand to help defer or reduce the scale of these capital-intensive projects.

3.4.3 Strengthening the network's resilience

Central Waitaha Canterbury faces significant natural hazard risks, including earthquakes, landslips, wildfires, and extreme weather events such as windstorms and floods. Climate-related change is increasing both the frequency and severity of extreme weather events, including storms, high winds, flooding, and wildfire. These risks are already being experienced across our network.

Natural hazards can cause substantial damage to electricity networks, leading to widespread and prolonged outages, as demonstrated by the 2010-2011 earthquakes, and Cyclone Gabrielle, which affected the North Island, in 2023. These outages create major disruption for households, businesses, and the wider economy.

The risk of vegetation coming into contact with our assets, and causing an unplanned outage, is expected to grow as warmer and wetter conditions accelerate vegetation growth, and higher wind speeds and more frequent storm events increase the likelihood of vegetation-related faults.

In consultation with our customers, they told us they expect our network to be resilient. They support reducing the risk of major outages, due to natural hazard events, and preparing the network to withstand the impacts of climate-related change.

3.4.3.1 Earthquake resilience

Research published in 2021 found there is a 75% chance of the Alpine Fault rupturing within the next 50 years, with more than an 80% chance this will cause an earthquake of magnitude 8 or higher.[10]

During the 2010 and 2011 earthquakes, parts of our underground network in Ōtautahi Christchurch City proved particularly vulnerable to seismic damage, primarily due to its reliance on obsolete oil-filled subtransmission cables. In addition, the architecture of the network severely impeded our ability to quickly restore supply after the earthquakes.

Since then, we have rebuilt and reconfigured the most heavily damaged sections of this network, including replacing four subtransmission cables that were damaged beyond repair with newer cable technology that provides improved seismic resilience. Subsequent expansions of our underground subtransmission network have been designed and constructed in line with this more resilient approach.

However, significant sections of our subtransmission network still rely on obsolete oil-filled 66 kV cables that are highly vulnerable to seismic damage. Although they remain in service, they are nearing the end of their life and present an increasing risk. As they supply the city centre and inner suburbs, a failure following a major seismic event would have widespread customer and economic impacts, making the current risk profile unacceptable. We are progressing reconfiguration of the remaining network and plan to fully replace these cables by FY38, materially improving resilience by reducing vulnerability to seismic damage, eliminating risks associated with oil-filled technology, and enabling faster fault isolation and restoration.

[10] GNS Science (n.d.) Alpine Fault magnitude 8 (AF8). Available at: https://www.gns.cri.nz/research-projects/alpine-fault-magnitude-8/ (Accessed: January 2026).

3.4.3.2 Climate-related risks

Climate-related risks are expected to increase over time as weather patterns continue to change. The frequency and severity of extreme weather events, including storms, flooding, and wildfires, are increasing.[11] Flooding events can damage underground assets and impede access for repairs. Severe windstorms place additional stress on overhead lines and structures.

Sections of our overhead network are particularly vulnerable to wildfire and landslip risks. This includes wooden poles in high wildfire risk areas and poles installed on steep slopes across the Port Hills and Banks Peninsula, which support critical lines supplying Diamond Harbour, Duvauchelle, Little River, and Akaroa. Fires in the Port Hills in 2017 and 2024 caused network damage and supply interruptions, demonstrating directly what asset vulnerability in these environments means for customers.

3.4.3.3 Vegetation management

We operate approximately 5,900 km of overhead lines, many running alongside hedges, shelterbelts, and mature trees, particularly in rural areas. Vegetation near overhead lines presents an ongoing risk to network reliability and public and worker safety, as falling or overhanging trees can cause supply interruptions, damage network assets, and create hazardous conditions during both normal operations and emergency response.

Vegetation-related incidents are a material driver of unplanned outages. Between FY21 and FY25, approximately 16% of unplanned interruptions on our network were attributed to falling vegetation, equating to around 4.9 minutes of interruption duration annually. This risk is expected to increase as climate change drives faster vegetation growth and more frequent and severe wind events.

The Electricity (Hazards from Trees) Regulations 2003 were amended in October 2024 to strengthen requirements for managing vegetation near electricity lines. The amendments are intended to improve the resilience of electricity supply infrastructure and enhance public safety. Orion supports these changes; however, compliance requires a substantial increase in our vegetation management activity and associated investment compared with historical levels.

A further set of amendments to the Regulations is currently in progress. Once gazetted, these are expected to strengthen vegetation management requirements further, increasing activity and expenditure requirements further.

To ensure compliance with the regulations, we need to take advantage of advanced tools, such as Light Detection and Ranging (LiDAR) which will enable us to accurately identify encroachments and overhangs, and target vegetation work more effectively.

3.4.4 Preparing for future energy needs

Technology is evolving rapidly and, as New Zealand transitions toward a low-carbon future, the way customers use our network is changing. Uptake of DERs, including electric vehicles, solar panels, and battery storage, is expected to increase as costs fall, making these technologies more attractive to customers seeking greater control over their energy supply and costs, and wishing to take advantage of opportunities to reduce their carbon emissions.

Through engagement, customers told us they expect Orion's network to be capable of supporting the connection and operation of these DERs. In response, we are planning a modest and staged investment programme over the next 10 years to explore, pilot, and implement new assets, systems, and processes. This programme will progressively transform our network and operations, so they are ready to meet future needs.

Initially our primary objective is to improve our understanding of how non-network solutions, such as demand-side flexibility and DERs, can be used to reduce peak demand. These solutions have the

[11] A storm hit New Zealand every eight days, on average, in the last year. See https://www.1news.co.nz/2026/04/21/a-storm-every-eight-days-claims-triple-to-countrys-biggest-insurer/ for further details.

potential to defer or reduce the need for capacity-driven network upgrades that would otherwise be required to support population growth and increasing electricity demand.

Other related objectives include leveraging smart meter data to identify emerging safety issues and to better understand how changing customer behaviours and emerging technologies affect our network, and to adapt our systems, processes, and operating practices accordingly.

Achieving these objectives requires improved network visibility to support the efficient and safe connection and operation of DERs and other low-carbon technologies. This, in turn, requires the acquisition of network data from metering service providers, giving rise to significant new costs that Orion has not traditionally incurred.

Over time, these investments will benefit customers by increasing safety and enabling greater choice and control over how they use electricity, supporting lower cost alternatives to traditional network investment, and ensuring the network continues to meet customers' needs as technologies and usage patterns evolve.

Our network transformation programme is detailed in Section 9 - Transforming our network.

3.4.5 Enhancing our ICT capability to increase efficiency

Following the Canterbury earthquakes, we deferred major upgrades to our core ICT systems. Our ICT strategy during this period prioritised maintaining business continuity and minimising disruption while we focused first on earthquake recovery, then on supporting remote working and workforce mobility during the COVID-19 pandemic.

While this approach was prudent in the circumstances, it meant that many of our ICT systems became outdated. By FY23, several key platforms were at, or beyond, the end of their useful life. Independent reviews by specialist consultants confirmed that, without significant renewal or replacement, these systems would not be fit to support our future business needs. There were also material gaps in our digital capability relative to good practice network management and customer service.

In FY21, we began a structured programme of system renewal and capability building to address these issues. We propose to complete this programme during the CPP period. The additional investment required is foundational to Orion's ability to deliver on other strategic priorities for the CPP period and beyond, including maintaining safety and reliability, strengthening resilience, and preparing to meet future needs. In the long-term, the programme will deliver benefits such as reduced cyber risk, increased labour efficiency and productivity, improved asset management and maintenance planning, and better customer service.

Our people and technology strategies are detailed in Section 8, with further detail in Section 15 – Managing our non-network assets.

3.5 Planning for an uncertain future

The growth-related aspects of our operating environment described in Section 3.4 present genuine uncertainty. The pace of electrification, population growth, technology adoption, and customer behaviour will all shape how our network needs to develop. However, none of these changes can be forecast with precision. We need a structured way to plan investments prudently across a range of possible futures.

We do this through two related tools: our Future Energy Scenarios (FESs), which define a range of plausible futures, and our Central Forecast, which represents our best-estimate view of how demand will evolve. The Central Forecast forms the basis for investment planning in this AMP.

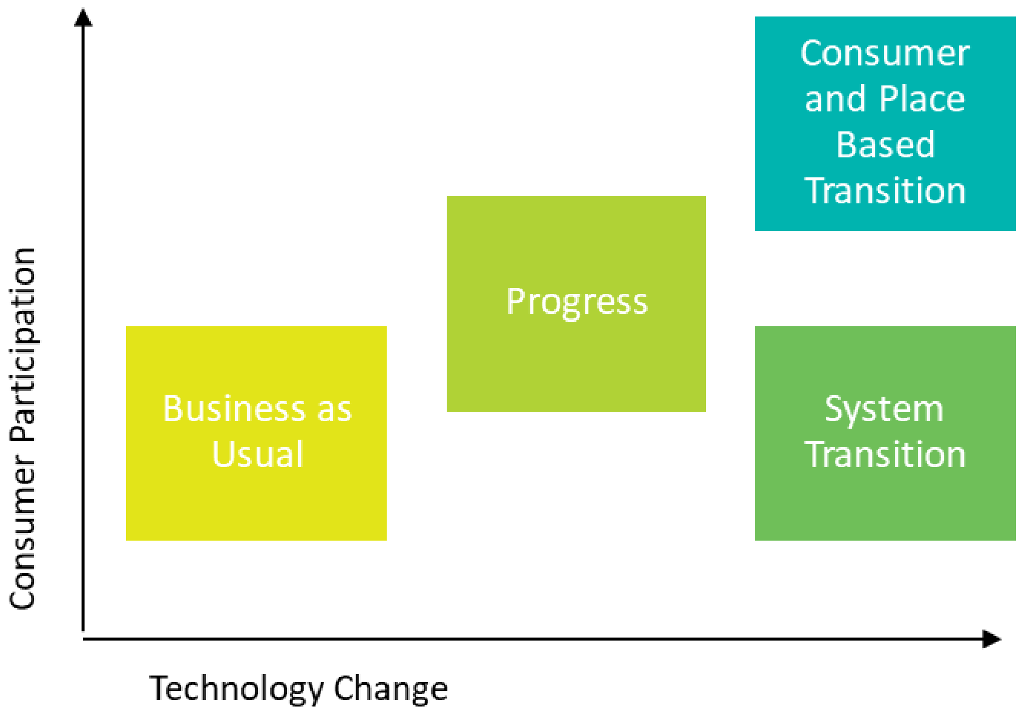
3.5.1 Future Energy Scenarios

Our FESs explore a range of plausible futures for our region by testing different combinations of the key drivers that shape our operating environment. The scenarios are not predictions of what will happen but are structured explorations of how different combinations of the drivers could reshape electricity demand and usage of our network over the next 10 to 30 years.

We have developed four scenarios, illustrated in Figure 3.7:

- **Business as usual**: While existing trends driven by largely external factors continue, there is little additional push towards decarbonisation in the New Zealand economy. Decarbonisation is generally high cost with little in the way of enabling technology shifts or reduction in prices. As a result there is little change in consumer behaviour, or incentive for people to interact with the energy system by way of flexibility or distributed energy resources.
- **Progress**: New Zealand and the rest of the world shifts further down the road on decarbonisation, but progress is slowed by high costs of transition and little significant change in technology and consumer behaviour. Some new smart technology is adopted and there is some increased use of residential flexibility.
- **System transition**: There is transitional change in the energy sector, with significant electrification and decarbonisation of electricity generation. Change is enabled by technology change, or existing technology becoming cheaper as innovation lowers production costs. Much of the change occurs at a system, or central, level. This means there is little change in the way consumers interact with the energy system and little optimisation at the consumer end of the value chain
- **Consumer and place-based transition**: New technology enables greater consumer participation in the energy sector, leading to an optimised and decarbonised energy system. Local area planning enables a place-based transition where use of existing assets is optimised, and optimised urban development reduces energy and transport demand.

Figure 3.7 Orion's Future Energy Scenarios



By testing these scenarios we found that peak demand growth on our network over the next 10 years could increase from approximately 16% (business-as-usual scenario) to 46% (system transition scenario). This range reflects the uncertainty inherent in our planning environment.

We developed our FESs through consultation and engagement with our community and stakeholders in 2023, to validate our inputs and assumptions, and gather local evidence. Full details are available in The Orion Group Future Energy Scenarios Report.[12] We update our FESs on an annual basis as new evidence emerges on technology adoption, policy, and local growth patterns.

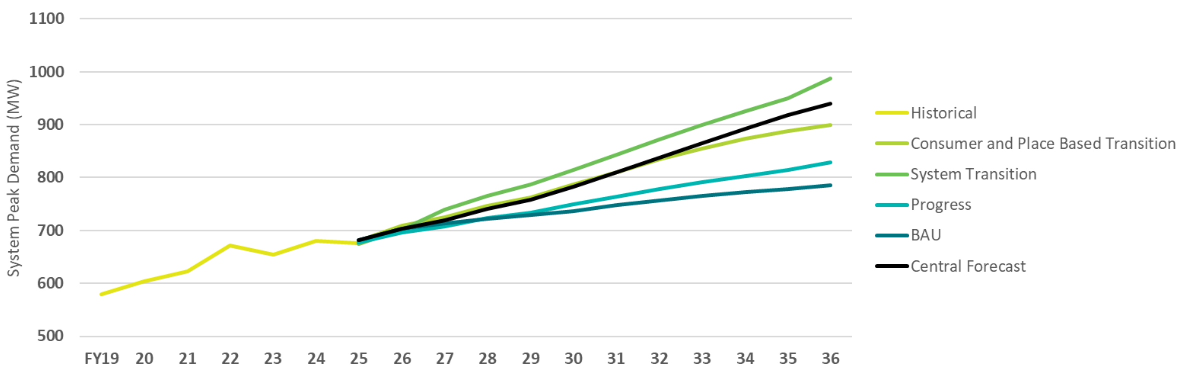
3.5.2 Our Central Forecast

Our Central Forecast is distinct from our FESs. That forecast represents our best-estimate view of how demand will evolve across our network, rather than describing a plausible future pathway.

Our Central Forecast forms the basis for all investment planning presented in this AMP. The Central Forecast reflects our view of the most likely combination of drivers for our regions: continued strong population growth, accelerating electrification of transport and process heat from approximately 2030, continued distributed generation growth, and sustained peak demand management through hot water load control and time-of-use pricing.

Under the Central Forecast, we expect network peak demand to grow over the 10 years from approximately 718 MW in FY25 to 939 MW by FY36, an increase of around 31%. Figure 3.8 shows this trajectory in the context of our FESs, illustrating both our planning basis and the uncertainty against which we are planning.

Figure 3.8 Network peak demand – Future Energy Scenarios and Central Forecast comparison



The technical methodology underpinning the Central Forecast, including demand drivers, modelling approach, and forecast inputs, is set out in Section 10. The resulting demand forecasts and network constraint analysis are presented in Section 11.

[12] See our Future Energy Scenarios Report for further details: https://www.oriongroup.co.nz/assets/Your-energy-future/The-Orion-Group-Future-Energy-Scenarios-Report-2024.pdf

4

4. Customers and stakeholders

Our purpose, described in Section 3.2, is powering a cleaner and brighter future with our community. To do this we must understand the needs and wants of the people who use and rely on electricity – our community.

As the energy sector moves through a period of unprecedented change, it is more important than ever that we understand what customers expect of us, and where they would like us to invest to support their vision for the future.

While all regions in New Zealand face the same energy transition at the macro level, each region's unique context means the challenges faced are not always the same. It is important we work with customers and key stakeholders to enable transition pathways that reflect our region's unique context, drivers, and community values.

4.1 Customers

Our customer base is diverse, including residential customers, small, medium and large businesses, and major and large-capacity customers. While the majority of customers are located within the Ōtautahi Christchurch urban area, a significant proportion are spread across rural and regional communities, reflecting the varied operating environments and service requirements across our network area.

4.2 Stakeholders

Stakeholder interests are summarised in Figure 4.1. Development of this AMP reflects the needs and perspectives of a diverse group of stakeholders, and while priorities differ, our engagement identified common themes that inform our asset management planning and project assessment. These themes include:

- safety was a non-negotiable expectation, with stakeholders having a high level of trust in the safe operation of the network
- affordability and value were key concerns, with stakeholders expecting prudent and efficient investment
- reliability and resilience were viewed as essential service expectations, particularly given the earthquake and severe weather risks faced by our region
- network readiness for growth and electrification was a key focus, with stakeholders seeking confidence the network can support rapid regional change
- use of technology, data, and non-network solutions attracted strong interest, especially where these can defer upgrades and manage new loads efficiently
- transparency was emphasised, with a preference for clear explanations of pricing, trade-offs, and investment decision-making
- delivery confidence was important, with stakeholders seeking assurance Orion can effectively manage and deliver on its investment plan
- strategic alignment was highlighted, with Orion's investment expected to support wider regional priorities and long-term planning objectives.

Figure 4.1 Stakeholders and their interests

4.3 How customer and stakeholder input informed AMP decisions

The activities set out in this AMP flow from our Strategic Asset Management Plan, which translates our organisational strategy into asset management objectives and decision-making principles. Customer and stakeholder feedback is integrated throughout this process, alongside asset information, risk assessments, and cost–benefit analysis, ensuring investment decisions respond to customer priorities while remaining prudent, efficient, and aligned with The Orion Group's strategy.

Orion's engagement programme, enhanced by our consultation and engagement on our CPP, was designed to understand what customers value and to test priorities across safety, reliability, resilience, growth, future needs, and affordability. Insights gathered through the Customer Advisory Panel, stakeholder meetings, community workshops, and customer research informed the development of three investment approaches—limited, balanced, and accelerated—which were consulted on through the 2025 AMP Update. This engagement highlighted what customer value most (safety and reliability), where concerns are most acute (affordability), and where there is willingness to pay for improved outcomes (resilience).

Customers expressed a clear preference for an investment approach that balances service outcomes, risk, and affordability. Through refined planning and forecasting, customer priorities were translated into defined investment programmes and network responses. Targeted engagement was then used to test price-quality trade-offs, including trade-offs between cost, reliability, resilience, growth, and future needs, to better understand impacts on customer bills, network performance, and risk tolerance.

The investment programme set out in this AMP reflects the feedback and insights from this engagement. While not every activity represents a direct customer choice between detailed project-level options, the overall programme is materially informed by customer priorities, values, and preferences, and demonstrates a clear line of sight from engagement insights to investment decisions.

4.4 Listening to customers

Managing and maintaining our infrastructure and operating our network efficiently and sustainably is only part of delivering on our purpose. To power a cleaner and brighter future with our community, our services must reflect what matters most to customers and contribute positively to their daily lives.

We develop this understanding of what matters most through ongoing, active engagement with customers and stakeholders to better understand their needs, expectations, and aspirations. Customers' perspectives help shape our decisions on the service we deliver, where and how we invest, and how we support the increasing use of new technologies to generate, store, and use electricity use at home, work, and in transport.

Figure 4.2 Customer engagement helps Orion to:

We use a range of methods to listen to customers and capture feedback, including:

4.4.1 Customer Advisory Panel

Orion's Customer Advisory Panel provides a valuable forum for engagement with representatives from community and industry groups, non-government organisations, and businesses, reflecting a broad cross-section of our customer base. With a strong customer advocacy focus, the Panel supports our understanding of customer needs, issues, and service expectations.

The Panel provides informed and independent perspectives on emerging issues and proposed initiatives, allowing us to test assumptions, explore trade-offs, and understand potential customer impacts early in the decision-making process. Insights from the Panel help shape our investment and asset management strategy, strengthen the customer evidence base for key decisions, and improve confidence that our planning reflects customer priorities.

4.4.2 Customer satisfaction research

To understand customer satisfaction with our services, views on network reliability, levels of trust in Orion, and perspectives on a range of topical issues, we commission an annual customer satisfaction survey.[13] The survey is conducted by independent researchers and engages a representative sample of approximately 1,000 urban, rural, and business customers across our region. This research enables us to track trends over time and identify variations across broad customer groups and locations. Insights from the survey are used to deepen our understanding of customer needs and expectations, and to inform where further engagement or targeted network investment would be most valued by customers.

4.4.3 "Powerful Conversations" workshops

These interactive community workshops bring together a mix of urban and rural, residential and business customers to explore complex issues in depth and test emerging ideas. The workshops support participants to progressively build their understanding of the energy sector and Orion's role, and to provide informed views on key trade-offs and investment priorities. We work with an independent research partner to design and facilitate the sessions, ensuring high-quality insights that inform our planning and decision-making. This approach enables deeper engagement with a diverse range of customers and provides a stronger understanding of customer needs and expectations.[14]

4.4.4 Direct engagement with customers

We engage directly with customers through meetings, interviews, and webinars to obtain detailed insights on specific issues and proposals. These formats enable structured discussion and allow customers to provide considered feedback based on their experiences and circumstances.

Direct engagement is used to understand customer priorities and trade-offs, and gather perspectives from defined customer groups, including business customers and other stakeholders with specific needs. Insights from this engagement complement broader engagement and are used to inform our planning, investment, and service decisions.

4.4.5 "Always on" Customer Support team

Our 24/7, local Customer Support Team talks with our customers daily about the service they receive. Through emails and around 2,100 calls per month we gain a rich understanding of what's important to our customers. These conversations enable us to respond to the immediate interests of our customers and identify any prevalent concerns or opportunities to continuously improve our service.

4.4.6 Snap Send Solve

Snap Send Solve provides a simple, accessible channel for our customers to report non-urgent issues on our network. The free mobile app, widely used by local authorities and utilities across Australia and New Zealand, allows users to submit photos and location information directly from their mobile phone. This supports timely identification of network issues, improves public safety outcomes, and enables faster and more efficient response.

[13] 2025 Customer Perceptions Survey - a mixed method of online and telephone surveys completed by 1077 customers who live (894) or operate a business (183) in our network area.

[14] In 2025 we ran six Powerful Conversation community workshops involving around 150 rural and urban customers, and held 15 in-depth interviews with 15 business customers.

4.4.7 Outage notification

Customers tell us that the reliability of our network is a priority. We know power outages are inconvenient, so keeping customers informed about outages, both planned and unplanned, reduces disruption.

In accordance with our Default Distributor Agreement (DDA), we provide planned outage information to electricity retailers and they notify affected customers. In some instances, we may notify customers directly. Our website also provides real-time details of both planned and unplanned power outages, and updates on our progress with restoration.

Customers can also report an outage through our website and sign up for our outage notification service. Customers who sign up to the service receive both email and text notifications in advance of planned outages, and updates should the outage change. This service is complementary to notification from retailers under the DDA.

4.4.8 Resolution of customer complaints

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

Orion's Customer Support team operates 24/7 and all team members are trained on how to respond to customer complaints. If not immediately resolved satisfactorily with the customer, the complaint is escalated to a dedicated resolutions specialist.

We keep a full record of all complaint interactions in our online Incident Management system. This ensures everyone dealing with the complaint is aware of the current position and provides a record of events should the matter become a legal or insurance issue or is escalated to Utilities Disputes Limited. We convene our Complaints Forum as needed to consider escalated complaints and decide on the course of action to be taken.

We routinely advise customers, through multiple channels, of their option to escalate their complaint for independent arbitration by Utilities Disputes Limited.[15]

4.4.9 Management of conflicting interests

Our aim is to always seek consensus and a "win-win" approach to negotiation when conflicting interests arise. We invite dialogue with all parties and have an open approach to providing the rationale for our position and are flexible in our consideration of possible alternative solutions. Except for safety matters, we generally take an empathetic approach to understanding alternative perspectives and needs and appreciate the value of a long term, positive relationship. While some of these issues present via our Complaints Forum, most are identified and resolved at the early engagement and design stage.

Occasionally, customers will provide differing views about what Orion should do in a particular situation. The nature of providing services through 'communal' infrastructure means that we are not always able to tailor solutions to meet individual needs. Where such conflicting views arise, we will consider all viewpoints and generally focus on delivering solutions that provide the greatest consumer benefit overall. Further information on how we prioritise and balance competing investment needs is provided in Section 16.8.

4.5 Community engagement

In addition to targeted customer engagement, we engage more broadly with our community to support understanding, transparency, and trust. This includes engagement on major projects, digital and social channels, community publications, sponsorships, events and public safety communications.

[15] In accordance with clause 11.30A of the Electricity Industry Participation Code 2010.

4.5.1 Major projects

Our communities expect to be informed about significant works that affect them, and we have strengthened our engagement approach for major projects accordingly. Where projects have the potential for material disruption, we provide enhanced and targeted communication and engagement with affected stakeholders and the wider community.

Our oil-filled 66 kV cable replacement programme, which often runs along busy roads in Christchurch, is an example of this enhanced approach. For these projects, we undertake proactive engagement with directly affected residents and businesses along the route, as well as commuters. Engagement activities may include an on-the-ground presence to provide information and issue resolution, distribution of Work Notices outlining the project scope, benefits, and service impacts, and the provision of clear points of contact. We also provide updates through emails and text messages, present to local Community Boards, place notices in local media, and share information through established community channels.

4.5.2 Social media

Orion reaches out to our community through social media. Through our LinkedIn and Facebook channels we are using storytelling to provide a new and deeper understanding of what we do. These two-way channels also provide us with another means to hear what's important to our customers and gather their feedback.

4.5.3 Orion "Have Your Say"

Making it easy for our community to engage with us is essential to understanding customer needs and expectations. Have your Say is a digital community engagement platform that enables accessible, two-way engagement with customers on matters that affect them. Through Have your Say we keep impacted customers informed about major projects and seek feedback through structured dialogue.

The platform provides a purpose-built website and a range of modern digital engagement tools that allow customers to participate on a variety of topics relevant to their community. This approach supports broader participation, timely feedback, and improved understanding of community views, helping to inform our planning and decision-making.

4.5.4 Orion Community Update

The Orion Community Update is a key channel for sharing information with our wider community in an accessible and engaging way. It provides updates on major network developments, our preparedness for natural hazard events, and our operations and services, as well as how we are planning for a changing energy future. The Update also includes practical information to help customers understand what to do during power outages and how to prepare for longer-duration disruptions.

The Community Update is distributed twice a year through community newspapers to approximately 110,000 households across Christchurch and Selwyn and is also available online. This broad reach supports awareness, understanding, and preparedness across the community.

4.5.5 Sponsorship and events

Sponsorships and events are another way we build relationships and maintain a visible presence in the communities we serve. Through targeted sponsorships and participation in local events, such as rural A&P shows, we engage directly with customers and our community on issues that matter to them, support community wellbeing, and improve understanding of our role as the local network owner. These activities provide informal but valuable opportunities to listen to community perspectives, share information about our work, and strengthen trust. Insights gained help inform our broader engagement approach and planning and decision-making.

4.5.6 Media and advertising

Through online, newspaper, magazine, and radio channels, our advertising campaigns focus on encouraging behaviours that support network reliability and public safety. Campaign topics include keeping trees clear of power lines (with tailored messaging for urban and rural audiences), farm safety around electricity infrastructure, DIY safety, and conversations about power line safety. Our “Dial it in” campaign also addresses the ongoing issue of people tampering with network assets by encouraging the community to report anything that does not look right.

4.5.7 Engagement on our draft CPP investment plans

In developing our proposed CPP, we took deliberate steps to strengthen and expand our engagement beyond business-as-usual. We combined targeted and participatory approaches, using both qualitative and quantitative research and formal public consultation processes. Our enhanced approach ensured we heard from a diverse cross-section of the community we serve and explored customer priorities and concerns in greater detail. By taking this more in-depth approach, we ensured our draft investment plans were informed by the communities who rely on our network every day.

Our engagement took an aggregated approach, with each phase building on the previous, ensuring that the customer voice was central to our planning and decision-making. The outcomes and insights from all phases form the foundation of this AMP and our proposed CPP.

Table 4.1 Engagement programme

Phase 1	Phase 2	Phase 3	Phase 4
Early engagement	Consultation	Consultation	Refinement
A research period to better understand customer needs, wants and expectations.	Broad and deep engagement on our proposed investment approach.	Broad and deep engagement on our draft CPP.	Developing and refining our CPP Application using insights from earlier phases.

4.6 What we heard, and how we are responding

Every conversation, workshop, and research outcome helps us to build a more responsive, and customer-focused electricity network. 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.

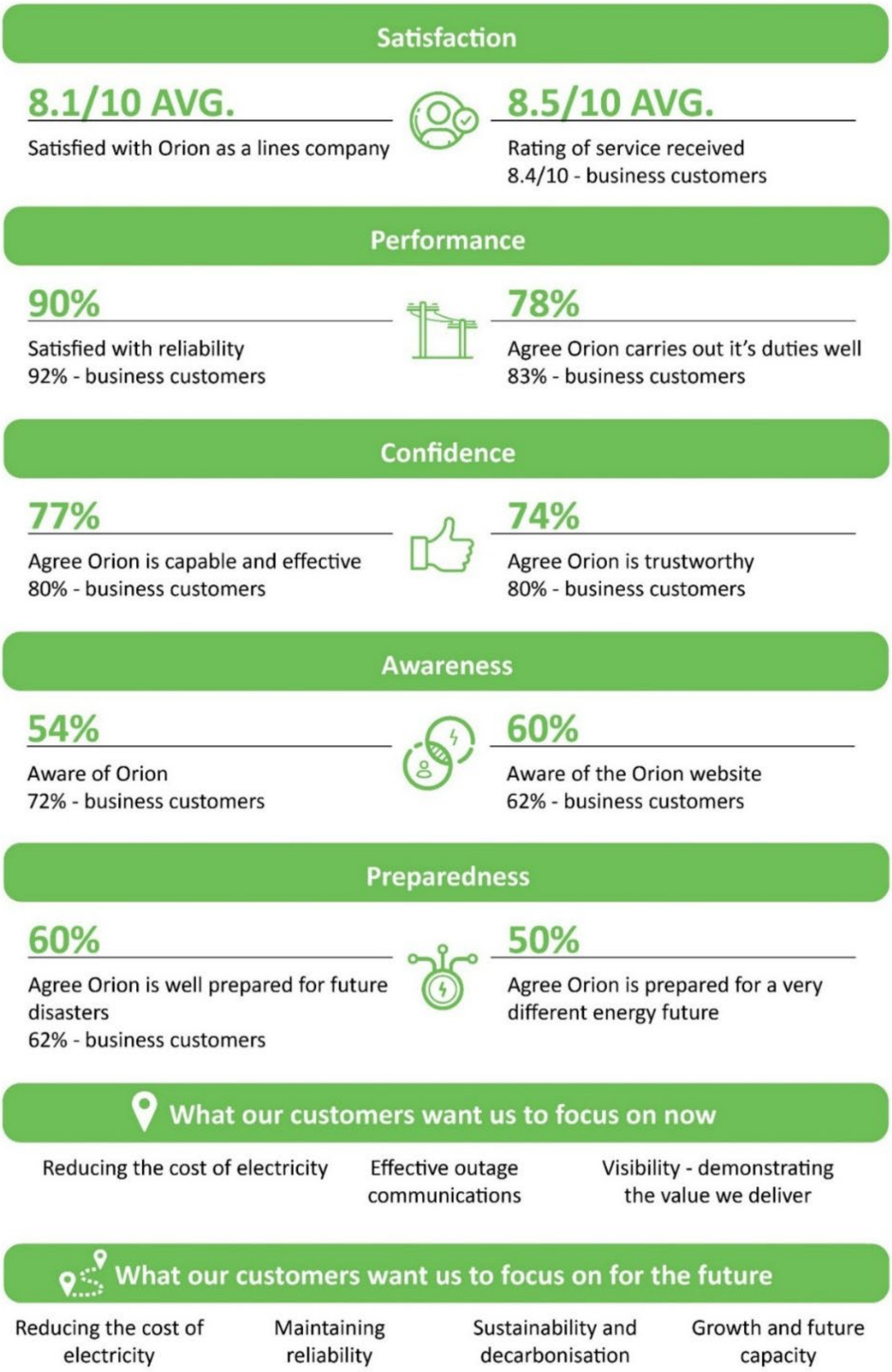
Customers consistently tell us they value a safe, reliable, and resilient network, while affordability remains critical. They also expect us to plan for growth and be ready for a changing energy future. In short, customers want electricity that is available when they need it, at a fair price, now and for the future.

Figure 4.3 shows the key results from our 2025 Customer Perceptions Survey. Where there were differences between our residential and business customer ratings, these are included.

Overall, customer feedback shows strong overall satisfaction with our performance, particularly in service quality and reliability. Confidence in Orion is high, with most customers agreeing we are capable, effective, and trustworthy, although awareness of Orion and its digital channels remain moderate. Preparedness for future challenges, including natural disasters and the energy transition, is viewed as adequate but with opportunities for improvement.

Our engagement highlights affordability as the priority concern for customers, particularly for more vulnerable members of the community. Customers also place strong value on clear and timely communication about outages and greater visibility of our role and activities as an electricity distribution business. Looking ahead, customers emphasise the importance of maintaining network reliability while supporting growth and the transition to a low carbon future.

Figure 4.3 Key results from our 2025 Customer Perceptions Survey[16]



[16] 2025 Customer Perceptions Survey - a mixed method of online and telephone surveys completed by 1077 customers who live (894) or operate a business (183) in our network area.

Through our engagement, our customers and community have identified seven key priorities, outlined in Figure 4.4.

4.6.1 Affordability

> ***"Even a few dollars more could put families like mine into poverty"***
>
> Powerful Conversations, 2025

Customers recognise the need for ongoing investment in the electricity network to maintain safety, reliability, and resilience. At the same time, affordability is consistently a key priority, and customers expect the cost of electricity to be carefully managed.

Our engagement shows that customers have a high level of confidence in Orion's capability and competence in managing the network, and expect asset management decisions to be well considered, focused on optimising outcomes over the asset life, and delivered in a way that provides good value while limiting impacts on price.

Affordability is a strong lens through which customers assess all investment priorities. Customers are concerned about the cost of electricity and want assurance that network investment does not place disproportionate pressure on power bills, particularly for more vulnerable communities.

Figure 4.4 Key customer priorities

Affordability

Good value for money and affordability of electricity, including investing in the right thing at the right time to balance risk, reliability and affordability.

Safety

A strong focus on safety, making sure our assets, systems, and the way we work keeps our people, service delivery partners and the community we serve safe.

Reliability

A reliable power supply that maintains current levels of reliability, with targeted improvements for localised areas.

Resilience

A resilient network, including improvements to reduce the risk of major disruption to the power supply during and after natural hazard events.

Growth

Capacity to meet regional growth and increasing demand while maintaining security of supply and reliability.

Future fit - new technologies

Capability and flexibility to support emerging technologies and greater customer control over electricity use, generation, and storage, including ensuring our systems are ready.

Customer experience

Timely and accessible communication regarding planned and unplanned outages.

4.6.1.1 In response, we are:

- Adopting our "proposed CPP," as outlined in our 2025 AMP Update, rather than alternative accelerated or limited investment approaches. Our balanced approach reflects limited customer appetite for investment above the proposed level, and minimal customer tolerance for a decline in service levels due to more limited investment. Our final CPP investment was reduced where possible to address affordability concerns, while maintaining service outcomes and other objectives sought by customers.
- Maintaining current levels of reliability, rather than investing to further improve reliability. Generally, customers have told us they do not want better reliability if it means higher prices.
- Exploring non-network solutions that moderate peak demand growth to help defer or reduce the scale of traditional capital-intensive projects.

4.6.2 Safety and reliability

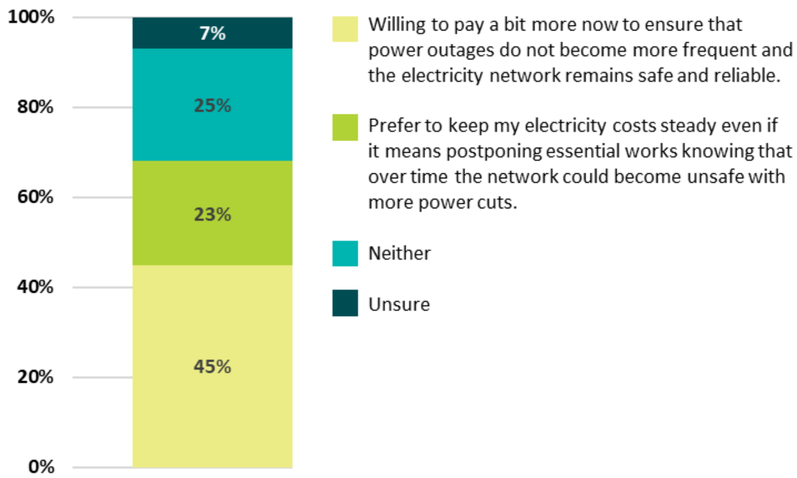
> ***"Reliability means that you have a power source at all times to be able to do what you need to do within your household and for work"***
>
> Powerful Conversations, 2025

Electricity is essential for powering customers' homes and businesses. Safety is regarded as a given, as customers trust that the network is operated safely at all times, and reliable supply is consistently identified as a top priority across all customer groups.

Customers are broadly satisfied with current reliability levels. Our 2025 Customer Perceptions Survey shows that 90% of residential and 92% of business customers are satisfied with current network reliability. This satisfaction does not translate into complacency: customers are not willing to accept lower reliability outcomes in exchange for reduced distribution charges.

When asked directly about trade-offs, the Customer Perceptions Survey found that 23% of customers preferred to keep costs steady, while 45% indicated they would accept paying a little more to avoid outages becoming more frequent: that is, to maintain current reliability rather than improve beyond it. A further 25% said neither, and 7% were unsure. This suggests customers broadly support maintaining current reliability levels, but are not seeking investment beyond what is needed to sustain current performance.

Figure 4.5 Customer feedback on reliability[17]



[17] Source: 2025 Customer Perceptions Survey, with 1,077 respondents. Average for residential and business customers combined.

4.6.2.1 What we are doing

We remain focused on ensuring customers can rely on us to keep the lights on. A strategic priority of our investment programmes is maintaining the network's safety and reliability by increasing asset renewal and maintenance to address the growing risks associated with ageing assets. Conscious of affordability, we are not looking to improve reliability levels, rather strike a balance between risk, reliability, and affordability. We plan to:

- Proactively increase asset renewal and maintenance activities to resolve past deferrals and an accumulated renewal backlog to ensure safety and reliability levels are maintained.
- Improve inspection regimes and scale up inspection activities to ensure we replace the right assets at the right time.

Our approach to maintaining our network's safety and reliability levels is covered in Section 13 – Operations and maintenance and Section 14 – Asset renewal.

4.6.3 Resilience

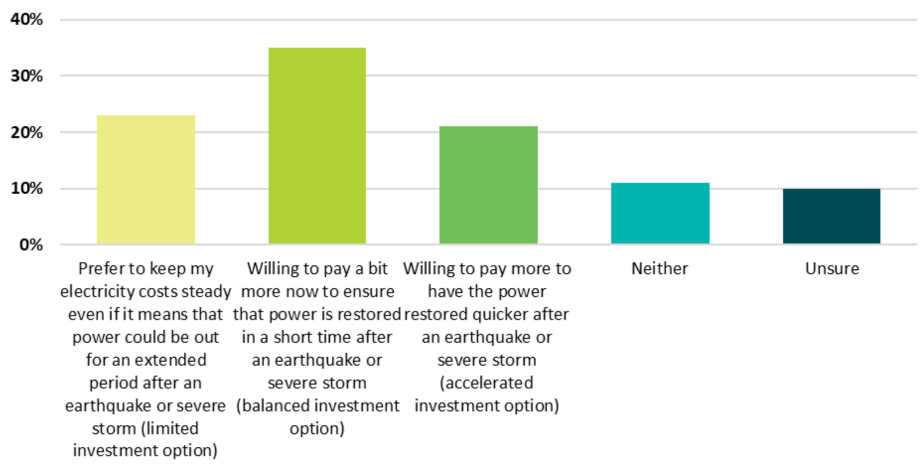
> ***"I was here for the last earthquake and if the Alpine fault goes, that will be much bigger. We need to protect our network as best we can "***
>
> Powerful Conversations, 2025

Our electricity network is essential infrastructure that the community depends on, and resilience is important to customers. Customers expect our network to withstand extreme weather events and natural hazards such as earthquakes and wildfires and have a low tolerance for prolonged outages when these events occur.

Customers consistently tell us that restoring electricity quickly following a major event or disruption is a high priority. Business and urban customers place particular value on network resilience, with urban customers generally reporting lower levels of preparedness for extended outages. Rural customers reported being more individually resilient, with greater access to back-up power options. However, they experience outages more frequently due to extreme weather events and place importance on timely fault resolution. Rural customers also highlighted the impact outages can have on productive activities.

Customers value resilience and expect Orion to take proactive steps to mitigate risks. This includes strengthening the network to better withstand disruptive events, as well as ensuring a fast and effective restoration response. Customers expressed support for resilience investment and a desire to better understand how Orion is preparing the network for future challenges.

Figure 4.6 Customer feedback on resilience[18]



[18] Source: 2025 Customer Perceptions Survey, with 1,077 respondents. Average for residential and business customers combined.

4.6.3.1 What we are doing

Natural hazards can cause substantial damage to electricity networks and a strategic priority of our CPP plan is to strengthen our network's resilience by renewing high-risk assets. We plan to:

- Replace older oil-filled cables on key circuits of the 66 kV subtransmission network to reduce the potential for widespread outages due to earthquake damage and to enable faster and more effective fault response and restoration.
- Begin proactively replacing poles vulnerable to wildfires to reduce the risk of unplanned outages and to lower the safety risk to the public, our staff, and service delivery partners.
- Increase vegetation management activities, recognising the increasing risk of unplanned outages driven by climate-related change, faster vegetation growth, and more severe windstorm events, while also reducing safety risks to the public, our staff, and service delivery partners.

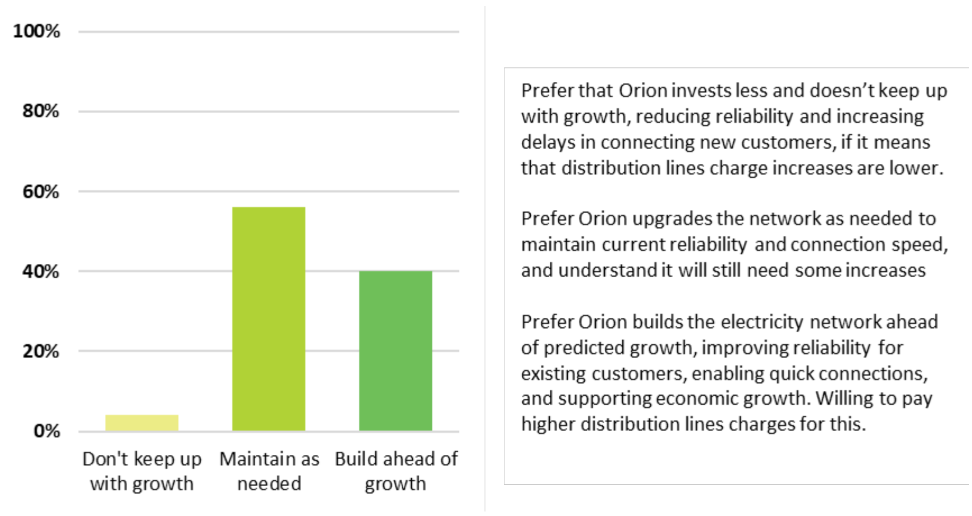
Our approach on strengthening our network's resilience is covered in Section 7 – Managing risk and Section 14.

4.6.4 Growth

> ***"I can't remember the last time we had a power cut. But if they keep building houses at the rate they are, that will be under threat. That is putting massive pressure on the network"***
>
> Powerful Conversations, 2024

Customers are well aware of the strong population and electricity demand growth occurring across the region, as households and businesses increasingly rely on electricity. They expect Orion to plan for this growth by building a future-ready network that can accommodate new demand without compromising safety or reliability.

Figure 4.7 Customer feedback on growth[19]



Through engagement, many customers came to understand that investment to support growth delivers shared, long-term benefits. These include maintaining the current reliability levels, providing sufficient network capacity, and enabling timely connections. Customers also recognised that the costs of long-lived network assets are spread over time across those who benefit, including new customers through connection charges and ongoing network charges. With this understanding, customers supported investment to enable growth.

[19] Source: Powerful Conversations, August 2025. Two community workshops involving around 60 residential and rural customers.

Customers recognised the opportunities offered by non-network solutions and many supported a hybrid approach to addressing capacity constraints, particularly where this could defer traditional, higher-cost upgrades without compromising security and reliability of supply.

Given how highly customers value safety and reliability, most were unwilling to accept a reduced level of service as a way of avoiding growth-related investment. While some favoured a 'maintain as needed' approach to help manage costs, others supported a 'build ahead of growth' approach to ensure adequate future capacity. Overall, customers expected growth investment to be well considered and cost-effectively delivering the right asset, in the right place, at the right time.

4.6.4.1 What we are doing

Our network area is experiencing strong and sustained growth. In response, one of our strategic priorities is to support this population and demand growth by extending and upgrading our network at emerging constraint points. We plan to:

- Continue investing more in customer connections to support approximately 4,400 new connections each year, and to support those large industrial customers who seek to decarbonise their operations.
- Continue investing in system growth by extending and upgrading our network to ensure sufficient capacity at peak demand and maintain security of supply. This includes building new zone substations and significant reinforcement of our distribution and low voltage networks.
- Explore and deploy non-network solutions that moderate peak demand growth to help defer or reduce the scale of these capital-intensive projects.

Our approach to supporting the strong population and demand growth in our network area is covered in detail in Section 12 – Network development programme.

4.6.5 Future fit – new technologies

> ***"The problem with investing in technology is its speed of change. In a few years, there might be a totally new solution, and if we have invested heavily in existing technology, we will be left behind again. Orion has to be measured in what they invest in right now."***
>
> Powerful Conversations, 2025

Customers recognise that technology is changing rapidly and that investment decisions need to account for uncertainty and pace of change. They expect Orion to take a measured and adaptive approach, avoiding over commitment to solutions that may quickly become outdated.

Customers increasingly expect greater flexibility and choice in how they generate, use, and store electricity. They want Orion to leverage emerging technologies and flexible solutions to help manage demand, reduce the need for costly network upgrades, and support the region's transition to a low carbon economy.

Through engagement, customers told us they see non-network solutions as a way to reduce pressure on the network during peak periods and enable more local generation and distribution. They view these solutions as important tools for managing affordability and strengthening resilience.

At the same time, customers expect a cautious and considered approach to investment in non-network solutions. They want Orion to remain adaptable, invest progressively, and proceed only where there are clear cost benefits and where safety, reliability, and resilience are not compromised. Customers also want to be part of the conversation, staying informed and partnering on future solutions.

4.6.5.1 What we are doing

Technology is evolving rapidly, and the way customers use our network is changing. A strategic priority of our investment is to prepare for future energy needs by exploring, piloting, and implementing new assets, systems, and processes to build the capabilities required to plan and operate our network in this changing energy environment. We plan to:

- Improve our understanding of how non-network solutions, such as demand-side flexibility and distributed energy resources (DERs), can be used to moderate peak demand, potentially reducing or deferring the need for capacity-driven network upgrades.
- Adapt our systems, processes, and operating practices to respond to changing customer behaviours and new technologies by improving network visibility and enabling the safe and efficient integration of DERs and low carbon technologies. This will support greater customer choice and control while ensuring our network continues to meet evolving needs as technology and usage patterns change.

Our approach to delivering on new technologies and non-network solutions is covered in detail in Section 9 – Transforming our network.

4.6.6 Customer experience

> ***"We understand things do go wrong, but when they go wrong, tell us what's wrong and tell us how quickly it's going to get resolved. And at least we can go to plan B."***
>
> Powerful Conversations, 2025

Reliability, accurate and timely outage information, and effective customer service are the service aspects most important to customers. Overall, customers report high levels of satisfaction with our performance, with customers rating 8.1/10 on average for satisfaction with Orion as a lines company, and 8.5/10 on average for service received.

Customers also tell us we are capable and effective and carry out our duties well, however they recognise that unplanned power outages occur. Some causes, such as asset deterioration, are within our direct control, while others, including some vegetation interference or vehicle impacts, are more difficult to influence. Customers expect us to focus on preventing and mitigating outages that are foreseeable and controllable through effective maintenance, renewal, and network management.

Customers told us that outages are disruptive, and that clear, timely communication reduces the impact. When unplanned outages occur, they expect accurate information and restoration timeframes. For planned outages, customers prefer personalised and direct communication well in advance.

While most customer interactions relate to outages, customers also want to be kept informed about significant works that affect them. They are also keen to better understand our investment programme and the asset management decisions that underpin network performance.

4.6.6.1 What we are doing

Modern Information Communications and Technology (ICT) systems are critical enablers of a safe, reliable, and customer focused electricity network. A strategic priority of ours is to enhance our efficiency and capability by completing our transition to a modern, resilient, and fit-for-purpose ICT environment. We plan to:

- Complete the structured renewal of ICT systems to strengthen network monitoring and management, improving network visibility, enabling faster outage response, and delivering more timely, accurate information to customers.
- Continue providing enhanced levels of direct communication and engagement where major projects have a significant impact on stakeholders and the community.

- Continue providing effective customer service through our 24/7, local Customer Support team. An enhanced ICT environment will support our team in providing timely and accurate outage information to customers
- Continue providing our opt-in outage notification service which uses text and email to update signed-up customers about planned outages. Again, an enhanced ICT environment will support this.

Our approach to delivering on customer experience is covered in detail in Section 5 – Service levels and performance and Section 8 – People and technology.

4.6.7 Investment priorities

> ***"Basically, I just want electricity when I want it – so to me, reliability is the most important thing. However, we know things do happen, whether it is a flood, or a car crash, etc, and when that happens, I want my power back on as quickly as possible, and I need Orion to do what it takes to make that happen, without going over the top. If there are new technologies out there that will help with either of those things, regardless of growth in population, or demand, or weather events, then that should also be considered."***
>
> Powerful Conversations, 2025

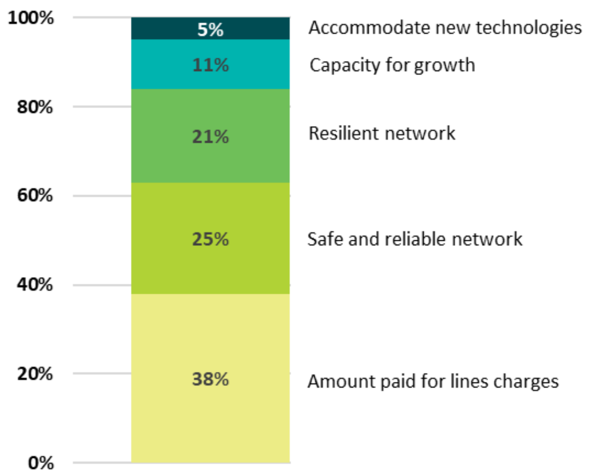
Customers want to see their priorities reflected in our investment and asset management decisions, and engagement showed clear and consistent themes. Safety and reliability are high priorities for customers, followed by resilience, capacity to support growth, and the ability to accommodate new technologies. Underpinning all of these is a strong focus on affordability and value.

Customers want affordability to remain front of mind in all investment decisions. They expect Orion to strike a careful balance: doing what is necessary to maintain a safe, reliable, and resilient network, restoring power quickly when disruptions occur, and considering new technologies where they provide clear benefits, without over investing or placing unnecessary pressure on electricity bills.

In our 2025 Customer Perceptions Survey, when asked to rank investment priorities, 38% of respondents ranked the amount paid in lines charges as their highest priority, shown in Figure 4.8. This was followed by a safe and reliable network, which 25% ranked as their top priority. A resilient network was ranked highest by 21% of respondents, while 11% prioritised capacity for growth. Accommodating new technologies was ranked the highest priority by only 5% of respondents.

In response to this feedback, our proposed investment plan focuses on maintaining safety and current reliability levels, strengthening resilience, and ensuring the network can support growth and new technologies, while avoiding unnecessary investment.

Figure 4.8 Customer feedback – ranking investment priorities[20]



[20] Source: 2025 Customer Perceptions Survey, with 1,077 respondents. Average for residential and business customers combined.

4.7 Consultation on key investment proposals

Feedback from customers and stakeholders on what is important to them is at the core of our approach to asset management. The proposed work programme set out in this AMP has been developed to ensure network investment is prudent and efficient, takes into consideration customer and stakeholder needs, and delivers the service they expect and rely on.

As part of our proposed CPP development process, we engaged on specific investment proposals to understand how customers value network services in relation to price and service quality.

4.7.1 Safety, reliability, and growth

> ***"If we plan for the worst now, we will do our best to protect ourselves against the growth and increasing frequency of weather events."***
>
> Powerful Conversations, 2025

Customer feedback is clear that a safe and reliable network is fundamental, with little tolerance for reduced reliability arising from network capacity constraints. When discussing the low voltage reinforcement programme, customers consistently favoured a conservative approach to managing risk. Around 87% preferred Orion to plan for the medium to worst case scenarios rather than accepting higher levels of constraint risk.

4.7.2 Resilience

> ***"We know what it was like after the earthquakes, how long it took to get power back. Without power, you feel so much more vulnerable and isolated – your phone does not work, you cannot buy fuel (pumps don't work), toilets don't work, and most people do not have heating. So whatever we can do to make sure that we can get electricity back quickly, we should do it."***
>
> Powerful Conversations, 2025

Customers consistently emphasise the importance of resilience. In relation to the 66 kV cable replacement programme, when asked to choose between limited, balanced, or accelerated investment options, around 80% preferred either a balanced approach (as included in this AMP) or an accelerated option.

This demonstrates strong support for targeted investment to ensure our network remains dependable, particularly following disruptive events. Customers told us they supported our proposed investment in poles vulnerable to wildfires. They mentioned the importance of a reliable electricity supply for rural areas, where outages tend to be more frequent and restoration timeframes can be longer.

4.7.3 Non-network solutions

> ***"We need to look to solutions that are more sustainable, maybe solar and batteries, that can benefit the whole community. This will likely involve investing in technology but could also help keep costs under control. Focus more on local solutions."***
>
> Powerful Conversations, 2025

Customers recognise the value of non-network solutions in supporting customer choice, affordability, and resilience. When asked whether they preferred limited, balanced, or accelerated investment in non-network solutions, 75% favoured a balanced approach. This reflects a preference for steady, considered investment that keeps pace with technological change while delivering clear, practical benefits to customers.

4.8 How customer priorities are embedded in asset management decision making

Our asset management system underpins how we plan, deliver, operate, and continuously improve our network. It provides a clear line of sight between the service levels our customers value and the investment decisions we make. The integrated processes, policies, strategies, and governance arrangements used to manage our assets and deliver customer value are described in Section 6 – Asset management system.

Customer feedback consistently highlights the importance of a safe, reliable, and resilient network, with affordability remaining critical. Customers also expect Orion to plan for growth and be prepared for a changing energy future. They want electricity to be available when they need it, at a fair price, both now and over the long term.

Reflecting the above feedback, our asset management approach is guided by the following:

- **Affordability**: ensuring asset management decisions and investment are prudent, efficient, and in the long-term interests of customers. This is achieved by balancing cost, reliability, and risk, and by targeting investment where it delivers the greatest customer benefit while avoiding unnecessary network investment.
- **Proactive asset renewal**: ensuring appropriate asset condition to maintain current levels of safety and reliability through proactive renewal and maintenance programmes and improved inspection regimes.
- **Network resilience**: strengthening the network's resilience to earthquakes, wildfire, and increasingly severe weather events by upgrading high-risk assets and expanding vegetation management activities.
- **Network growth and development**: ensuring sufficient network capacity to support forecast growth while maintaining current levels of reliability and security of supply, through targeted investment in customer connections and system growth.
- **Preparing for the future**: building capability to plan for and operate the network in a changing energy environment by exploring, piloting, and implementing new asset systems, data, and processes.
- **Customer experience**: improving network visibility, outage response, and customer information, enabled through completing our transition to a modern ICT environment.


5

5. Service measures and performance

5.1 Our service measures, targets, and performance

Our service measures set out what customers can expect from us over the AMP period and the commitments we are making to deliver it. The service measures in this section have been deliberately selected to align to our five investment priorities (outlined in Section 3.2.4) that were supported by customers during consultation on our proposed CPP Application. They balance customer priorities, regulatory requirements, and the practical realities of operating an electricity distribution network.

Each service measure has a target level of performance. Each target level of performance has been determined using one or more of the following:

- historical performance
- consumer engagement outcomes, including our 2024 and 2025 Customer Perceptions Report, Customer Pulse Survey 2025, and our CPP-specific engagement programme
- regulatory requirements set by the Commerce Commission in the DPP4 decision
- benchmarking against comparable New Zealand electricity distribution businesses (EDBs)
- considering whether future investment is likely to influence service levels.

Where a new service measure is being introduced for the first time, we have set an initial target to establish a baseline and indicated that the target may be reviewed once initial data is available.

The tables in this chapter set out annual targets for each year of the AMP planning period (FY27 to FY36). Where targets are flat across all years, this reflects our intent to maintain performance levels. Where targets vary, this reflects expected performance improvements. For some new service measures being introduced from FY28, we have indicated "monitoring" for FY27 to reflect the data-gathering phase before formal targets are set for the AMP period.

We track our performance against our service measures and targets on an ongoing basis and report through the following channels:

- **Internal reporting**: performance is monitored regularly through the year and reported to our leadership team and Board.
- **Annual reporting**: we report our performance to customers and stakeholders in our Asset Management Plans.
- **Regulatory reporting**: we provide performance information to the Commerce Commission and Electricity Authority as required.

When we identify underperformance, we conduct investigations to understand the root causes and determine appropriate corrective actions. Our approach to continuous improvement ensures that lessons learned are embedded in our processes and inform future investment decisions.

5.1.1 Evaluation of performance against previous AMP targets

The table below compares our actual service measure performance in FY24 and FY25 against the targets set in our 2024 AMP.

Table 5.1 Evaluation of performance against 2024 targets

Service Area	Performance service measure (KPI)	2024 AMP target for FY24 and FY25	FY24 actual result	FY24 achieved? (Yes/No)	FY25 actual result	FY25 achieved? (Yes/No)	Commentary on any significant variances
Safety	Safety of Orion Group employees	≤4 serious events	3	Yes	1	Yes	
	Safety of service providers	≤4 serious events	1	Yes	1	Yes	
	Safety of the public	≤1 serious event	0	Yes	1	Yes	
Reliability	SAIDI Planned	FY21–25 limit <198.81	16.0	Yes	17.8	Yes	
	SAIDI Unplanned	Limit <84.7	39.6	Yes	23.4	Yes	
	SAIFI Planned	Limit <1.03	0.08	Yes	0.10	Yes	
	SAIFI Unplanned	No limit (monitored)	0.63	n/a	0.42	n/a	
	Unplanned interruptions restored within 3 hours	>60%	67%	Yes	75%	Yes	
Power Quality	Number of escalated customer complaints	<60	39	Yes	21	Yes	
	Number of proven harmonics or distortion complaints	<4	2	Yes	2	Yes	
Security of Supply	No. of breaches in the Security of Supply Standard - Transpower GXP	≤2	1	Yes	0	Yes	
	No. of breaches in the Security of Supply Standard - Subtransmission	≤6	1	Yes	2	Yes	
Operational efficiency	Operational expenditure per MWh	<NZ comparator average	96% of comp. average	Yes	91% of comp. average	Yes	
Environmental sustainability	SF_6 gas lost	<0.8%	0.18%	Yes	0.14%	Yes	
	Grams CO_2e per MWh delivered (excl. distribution losses)	<200g	725	No	616	No	See note 1 below table
Customer experience	Customer experience: service received	8.8 out of 10	8.1	No	8.3	No	See note 2 below table
	Customer experience: ease of doing business	8.9 out of 10	8.8	No	8.3	No	See note 2 below table

Service Area	Performance service measure (KPI)	2024 AMP target for FY24 and FY25	FY24 actual result	FY24 achieved? (Yes/No)	FY25 actual result	FY25 achieved? (Yes/No)	Commentary on any significant variances
System growth	% of transformers monitored across LV network	9% for FY24	8.7%	No	10.4%	Yes	Slight delay in FY24 rollout of monitors
	Network-led flexibility: capacity available through hot water load control	100MW	190MW	Yes	190MW	Yes	

Notes:

1. *The CO_2e gas lost target of <200g was set to recognise long term reduction aspirations and was set before we became more mature in this area - it splits the difference between our FY30 target and our FY50 target. As carbon management within the business has matured, we are able to define both our near term and our mid-term targets more specifically, recognising the anticipated uplift in operational work over that period. We do not propose to use long-term targets for reporting over this AMP period. Instead, we have adopted targets that reflect our anticipated improvements over the period.*
2. *In FY24 we moved from Net Promoter Score to Customer Satisfaction scoring. NPS measures loyalty, which has limited meaning in a monopoly context, and the change gives us more actionable insight into where customers want us to improve. The FY24 and FY25 targets were set against FY23 NPS scores and are not directly comparable to Customer Satisfaction results. Based on our customer engagement outlined in Section 4, we are confident that the apparent gap reflects the change in methodology, not a reduction in service quality.*

The sections below set out our service measures and targets for each service area across the AMP planning period.

5.1.2 Safety

Safety is our highest priority. We are committed to ensuring that everyone who interacts with our network, including our staff, service delivery partners, customers, and the public, goes home safely every day.

5.1.2.1 Our safety service measures and targets

We will track the service measures shown below.

Table 5.2 Safety performance service measures

Service measure	Annual target to FY36
Notified events that result in serious injury to employees	≤ one serious event per year
Notified events that result in serious injury to service delivery partners	≤ one serious event per year
Events that result in serious injury to the public, excluding car versus pole incidents	≤ one serious event per year

The target of ≤1 serious event for each safety measure reflects our historical performance and commitment to continuous improvement, acknowledging that some potential-consequence events will inevitably occur across a large workforce undertaking hazardous electrical work.

5.1.2.2 What our service measures mean

A serious event is defined as an event that results in death or injury requiring immediate hospital treatment.

5.1.2.3 Our approach to safety

Our safety performance is underpinned by a comprehensive safety management system that includes:

Proactive safety management, including:

- regular safety training and competency assessments for all staff and service delivery partners
- pre-job safety planning and hazard identification processes
- condition-based monitoring to identify and address asset safety risks before failure
- vegetation management programmes to maintain safe clearances around overhead lines.

Incident management and learning:

- comprehensive incident investigation
- near-miss reporting and analysis to identify emerging risks
- regular safety audits and inspections of work practices.

Public safety initiatives:

- public safety campaigns to raise awareness of electrical hazards. Key initiatives include targeted advertising about working near overhead lines, reporting theft and damage of electrical equipment, and information for tree owners
- clear signage and barriers around network assets where appropriate.

Service delivery partner management:

- robust service delivery partner selection and accreditation processes
- shared safety culture and expectations across all service delivery partners.

Customers strongly supported increased investment in renewing ageing assets in the proposed CPP Application, recognising that asset condition directly affects safety outcomes for workers, the public, and customers.

5.1.3 Reliability

Reliability measures how often and for how long our customers experience power outages.

Our reliability performance has followed a clear improvement trajectory following the 2010-11 Canterbury earthquakes. The number of unplanned outages reduced materially through the recovery period and broadly stabilised around 2019-20. Since then, performance has shown typical year-to-year variation reflecting weather conditions and operational factors, which is consistent with the experience of other comparable networks.

During engagement for our CPP application, customers indicated that they are satisfied with current reliability levels, and that there is limited appetite for additional investment targeted at reliability improvement beyond maintaining what they already receive, except for improving in targeted, localised areas. Our investment programme is designed to maintain this performance, not materially exceed it.

5.1.3.1 Our reliability service measures and targets

We will continue to track the service measures shown below.

Table 5.3 Reliability performance service measures

Service measure	Annual target to FY36	
	Planned interruptions	Unplanned interruptions
SAIDI (minutes per customer, per year)	≤ 23.83	≤ 63.14
SAIFI (frequency per customer, per year)	≤ 0.074	≤ 0.795
Unplanned interruptions restored within three hours	N/A	≥ 60%

Our SAIDI and SAIFI targets are reflective of the Commerce Commission's (Commission) DPP4 quality standards decision. These targets are reviewed and updated at regulatory resets. The Commission requires that EDBs maintain reliability near historical levels under a principle of "no material deterioration." The targets above reflect the DPP4 quality standard settings and will be revisited once the Commission determines our quality standards for the CPP period.

For the target of restoring 60% of unplanned interruptions within 3 hours, this target has been maintained from our 2024 AMP. It reflects our historical restoration performance and provides a meaningful measure of operational responsiveness.

Starting in FY28 we will track two further service measures:

Table 5.4 New reliability performance service measures

Service measure	Initial FY28 target - reviewed annually from FY29 onwards based on learnings
Percentage of planned interruptions where less than 10 working days' notice is given to electricity retailers	≤ 20%
Number of localised reliability hot spots with an approved corrective action within six months of identification	≥ 3

The target of ≤20% of planned interruptions given less than 10 working days' notice reflects our FY24 and FY25 average performance and our intent to maintain or improve on this as delivery activity scales up over the CPP period.

Because the localised reliability hot spot measure is a new service measure being introduced in FY28, we have set an initial target of 3 or more hot spots per year to establish a baseline. The target will be reviewed annually from FY29 onwards based on learnings.

5.1.3.2 What our service measures mean

SAIDI (System Average Interruption Duration Index) measures the average total duration of outages experienced by customers over a year, expressed in minutes.

SAIFI (System Average Interruption Frequency Index) measures the average number of interruptions experienced by customers over a year.

We report on these two service measures for both planned interruptions, i.e. scheduled maintenance with advance notice, and unplanned interruptions, i.e. unexpected faults and failures.

Consistent with regulatory requirements we exclude extraordinary circumstances, such as severe storms or earthquakes, from the calculation of our SAIDI and SAIDI service measures to avoid distorting underlying performance.

Our target of restoring power within three hours of an unplanned interruption measures our responsiveness in restoring supply, demonstrating effective response processes including remote switching capability and stand-by fault response crews.

In relation to our two new service measures:

- reliability hot spots are specific areas that are experiencing disproportionately high interruption frequency or duration and/or the network is performing below design configuration expectation. Identifying and addressing these areas directly responds to customer feedback about improving reliability in localised areas.
- notification of planned interruptions measures our ability to provide adequate advance notice to electricity retailers, who are then responsible for notifying their customers about planned outages that will affect them.

5.1.3.3 Our approach to maintaining and improving local area reliability

While weather and remote rural networks, that have longer lines and fewer alternative supply routes, will always impact on our reliability performance, we are implementing multiple initiatives to maintain and improve localised network reliability. Some of which are:

- asset renewal and replacement: older assets are more likely to fail unexpectedly, and equipment deterioration increases fault frequency.
- enhanced vegetation management: trees and branches coming into contact with our lines are a major cause of faults.
- network automation and reconfiguration: meshed networks and automation allow faster restoration.
- operational improvements: predictive maintenance, field crew availability, fault-finding efficiency, repair quality.
- data analysis to enable improved targeting of maintenance and replacement activities.

5.1.4 Power quality

Power quality refers to the characteristics of electricity supply, such as harmonics, frequency, and voltage. Power quality is increasingly important as customers adopt solar PV, batteries, electric vehicles, and other technologies that create two-way energy flows.

Voltage is a key focus area because manufacturers design most electrical equipment to operate within specific voltage ranges. Voltage outside these ranges can cause equipment malfunction and potential fire risk. Maintaining voltage within acceptable ranges also enables continued uptake of distributed energy resources without compromising safety or reliability.

After obtaining access to smart meter network operational data in October 2023 for approximately 90% of our customers, we carried out a comprehensive network-wide analysis of regulatory voltage compliance, assessed against the current ±10% limit set out in the Electricity (Safety) Regulations 2010.

For the small number of customers identified as currently sitting outside the ±10% regulatory limit, we are assessing and implementing both temporary and long-term mitigation options using network optimisation and reinforcement techniques, including transformer and overhead line upgrades.

5.1.4.1 Our power quality service measures and targets

We will continue to report on the following two power quality service measures, utilising the same targets as in the 2024 AMP, before these two service measures are discontinued in FY28 as explained in Section 5.1.9.

Table 5.5 Existing power quality performance service measures

Service measure	Target for FY26 and FY27
Number of escalated customer complaints	≤ 60
Number of proven harmonics or distortion complaints	≤ 4

We will track, and publish, our performance against three new service measures, shown below, from FY28. The shift reflects a deliberate move from counting complaint inputs to measuring service outcomes, specifically, how fast we respond and how quickly we resolve issues.

Table 5.6 New power quality performance service measures

Service measure	Annual target to FY36
Timeframe for when customer complaints relating to network power quality issues are responded to after the issue has been logged.	100% in ≤ five business days
Percentage of validated customer complaints relating to network power quality issues that are resolved within one month after the proposed remedy is identified.	≥ 90%
Percentage of proactively identified network power quality issues that are resolved within five business days, e.g. broken neutrals, high impedance neutrals.	≥ 90%

The 5-business day response target is aligned to our current Default Distributor Agreement (DDA).

The 90% resolution-within-one-month target and the 90% proactive resolution target reflect our commitment to prompt action.

5.1.4.2 What our service measures mean

Resolution of power quality issues measures our effectiveness in fixing identified problems, once we know the solution. Customers expect that once we have investigated and identified the remedy, that we will implement it promptly, typically within one month at most.

Response timeframes measure how quickly we acknowledge and begin investigating complaints. Five business days represents good practice, demonstrating our commitment to addressing customer concerns.

Proactive identification and resolution measures our ability to find and fix issues before they generate customer complaints. Issues such as broken neutrals or high-impedance neutral connections can cause significant power quality problems and safety risks. Identifying and resolving issues proactively demonstrates our commitment to maintaining high-quality supply.

5.1.4.3 Our approach to power quality

We take a systematic two-stage approach to power quality: firstly, we identify issues through comprehensive monitoring, secondly, we implement targeted solutions.

Aside from using routine inspections to identify issues such as broken neutrals or high-impedance connections, we continuously monitor power quality across our network through multiple data sources including:

- power quality meters at zone substations and key distribution points. These provide real-time monitoring of voltage levels, harmonics, and other parameters, generating automatic alerts when measurements fall outside acceptable ranges
- smart meter voltage data. This gives us visibility at the individual customer connection level. We currently access approximately 90% of customer smart meter data, helping us identify localised voltage issues[21]
- distribution transformer monitoring. This provides highly precise voltage measurements at the low voltage level, helping to pinpoint exactly where issues are occurring, and covers approximately 13% of distribution transformers across our network.

These data sources are used in Orion's LV analytic platform, Future-Grid Compass, to alert on voltage quality issues and regulatory limit breaches for further engineering analysis and resolution. Our monitoring enables us to identify issues proactively before they cause customer problems, as well as respond effectively to reported concerns.

When voltage quality issues are identified proactively through our monitoring systems, they are prioritised by type and severity to determine the appropriate response and urgency. Issues assessed as emergencies are resolved through our existing emergency works processes. For lower-urgency issues, work is budgeted and scheduled.

Where further information is required, field inspections may be conducted and/or high-resolution power quality monitoring may be installed to confirm the issue and develop appropriate solutions.

For proactively identified voltage quality issues, we do not typically contact affected customers unless the works being undertaken require access or cause a supply interruption.

When voltage quality issues are raised by a customer or other stakeholder, a similar investigation process occurs and we will communicate directly with the affected party any actions, repairs or upgrades required. Once we have identified an issue and determined the appropriate remedy, we implement targeted solutions including:

- voltage regulation through adjusting transformer settings, installing line voltage regulators, or deploying equipment to bring voltage within optimal ranges
- network reinforcement by upgrading conductors, installing larger transformers, or reconfiguring the network to provide shorter supply paths
- specialised devices such as harmonic filters, capacitor banks for power factor correction, and dynamic voltage support devices for specific power quality issues.

Historically, our voltage quality improvement work has been primarily customer-initiated. As we transition to a more proactive approach, we are focused on improving our prioritisation systems, issue tracking, and reporting processes. The new service measures introduced from FY28 reflect this shift - moving from counting complaint volumes to measuring how quickly we respond to and resolve power quality issues, and how effectively we identify and address issues before customers are affected.

Looking forward, we anticipate an increasing need to manage the risk of network congestion from growing levels of distributed generation export. In response, we have developed a Congestion Management Policy.[22] The Policy aims to provide equitable access to available export capacity, ensuring no customer is advantaged or disadvantaged by when they connect. It also aims to maximise the export opportunity for customers over time via a transition from static to dynamic export limits.

[21] Section 9.3.1, LV network monitoring practices, provides further information on our progress in procuring data to support LV network management, and our use of network analytics on the LV network.

[22] Available on our website: https://www.oriongroup.co.nz/connections/network-connection-standard

5.1.5 Network planning and operations efficiency

Network planning and operations efficiency is critical to delivering long term affordability. Customers support prudent investment that avoids both overbuilding the network and exposing customers to unnecessary reliability risk.

5.1.5.1 Our network planning and operations efficiency service measures and targets

We will continue to track the service measure shown below.

Table 5.7 Operational efficiency performance service measures

Service measure	Annual target to FY36
Operational expenditure per MWh	≤ NZ comparator group average

The operational expenditure per MWh service measure is retained from our 2024 AMP. The comparator group comprises Wellington Electricity, WEL Network, and Unison. These networks have broadly comparable customer bases, asset volumes, and network sizes, and they also, like Orion, serve a mix of dense urban areas and growth-driven rural areas.

Starting in FY27 we will track one further service measure:

Table 5.8 New operational efficiency performance service measures

Service measure	Annual target to FY36
5-year rolling average of total network MWh / total expenditure	Five-year change in measure exceeds the average change across comparator EDBs

The 5-year total MWh to total expenditure target has been set as total expenditure captures all network investment rather than solely operating expenditure or capital expenditure. Given total expenditure in any one year can vary significantly a 5-year rolling average will be measured to provide a good indication of efficient improvement over the long term. In FY25 we met the proposed target with a result that was approximately 5% better than comparator EDBs.

Starting in FY28 we will add and track one further service measure:

Table 5.9 New operational efficiency performance service measures

Service measure	Annual target to FY36
Average load (kW) as a percentage of firm capacity of transformers (weighted by customers supplied by that transformer)	To be determined

The transformer utilisation target reflects our intent to make efficient use of existing infrastructure while maintaining security of supply. Firm capacity is the N–1 rating for zone substations, and the nameplate rating for distribution transformers. The measure is a customer-weighted average of individual transformer load-to-firm-capacity ratios across the network. In FY26 and FY27 we will be calculating this measure to determine a target that will be set for it in the years FY28 to FY32.

5.1.5.2 What our service measures mean

We measure cost efficiency through operating expenditure and total expenditure per MWh. By comparing our result to a group of similar New Zealand EDBs, we can assess whether our costs are reasonable.

The new target of transformer efficiency measures how adept we are at using installed capacity on our network. We are measuring this at transformer level rather than zone substation level to ensure we examine our efficiency at a level that includes low voltage not just high voltage. Very low utilisation means we have excess capacity, which means inefficient capital use, while running too close to capacity increases overload and interruption risk.

5.1.5.3 Our approach to improving efficiency

We drive efficiency through smart network planning and operational practices. Our planning uses load forecasting, network modelling, and cost-benefit analysis to identify the most cost-effective solutions. We evaluate non-network alternatives, such as demand response and energy storage, alongside traditional reinforcement.

Operationally, we optimise asset lifecycles, use condition-based maintenance, standardise equipment, and coordinate work delivery. We benchmark our performance against other New Zealand EDBs to identify improvement opportunities and validate our performance.

5.1.6 Environmental impact and sustainability

As a major infrastructure provider, we have both a responsibility and an opportunity to minimise our environmental impact and support New Zealand's transition to a low-carbon economy.

5.1.6.1 Our environmental service measures and targets

We will continue to track the service measures shown below.

Table 5.10 Environmental performance service measures

Service measure	Annual target to FY36
Sulphur hexafluoride (SF_6) gas lost	≤ 0.8% of total installed SF_6 inventory
Grams of Carbon Dioxide equivalent (CO_2e) per MWh delivered	≤ 700g to FY28 inclusive ≤ 580g for FY29 and FY30 ≤ 450g for FY31 to FY36

The SF_6 target of ≤0.8% reflects our historical performance and good international practice for managing this potent greenhouse gas.

The carbon emissions targets represent a reduction from our FY23 baseline and reflect our ongoing fleet electrification and energy efficiency programme.

5.1.6.2 What our service measures mean

Sulphur hexafluoride (SF_6) is an extremely potent greenhouse gas used in some high voltage switchgear. One kilogram of SF_6 has the same global warming potential as approximately 23,500 kilograms of CO_2. We measure leakage as a percentage of total installed SF_6 inventory, with a target of 0.8% or less.

We track greenhouse gas emissions through our operational carbon emissions target for our direct operations - Scope 1 and 2.[23] Our target includes emissions from our vehicle fleet, backup generators, and purchased electricity for our facilities, but excludes distribution losses.

5.1.6.3 Our approach to environmental impact and sustainability

We manage SF_6 leakages through regular inspections and pressure monitoring, prompt leak repairs, specifying SF_6-free alternatives for new switchgear, and proper disposal procedures at an asset's end of life.

We reduce our operational carbon emissions through our vehicle fleet transitioning to electric and hybrid vehicles, energy efficiency improvements in our facilities, and optimised work practices, e.g. remote monitoring and operation to reduce site visits.

[23] Scope 1 emissions are those produced directly from sources owned or controlled by Orion, while Scope 2 emissions are the indirect emissions associated with purchased electricity consumed by Orion.

Oil and hazardous materials are managed through containment systems and proper disposal, recycle metals from retired assets, and consider biodiversity and heritage factors in our construction activities.

Our most significant contribution to environmental sustainability is enabling New Zealand's transition to a low-carbon economy through connecting renewable distributed generation, supporting electric vehicle uptake, and providing the reliable electricity supply needed for electrification.

5.1.7 Customer service

Customer service excellence is fundamental to our social license to operate. We aim to provide responsive, helpful, and professional service to all customers who contact us. Customers tell us they value clear communication, accurate outage information, and simple processes.

5.1.7.1 Our customer service measures and targets

We will continue to track the service measures shown below.

Table 5.11 Customer service performance service measures

Service measure	Annual target to FY36
Customer experience: rating of service received	≥ 8 out of 10
Customer experience: ease of doing business with us	≥ 8 out of 10

The customer experience scores (≥8 out of 10) reflect both our historical performance and the strong consumer support for maintaining existing service quality.

Starting in FY28 we will track three further customer service metrics:

Table 5.12 New customer service performance service measures

Service measure	Annual target to FY36
Awareness of Orion's website	≥ 50%
Percentage of customers restored within ±30 minutes of the communicated restoration time for planned HV outages	≥ 30%
Percentage of small generation (<10 kW) connections approved within 10 business days after receipt of completed applications	100%

The website awareness target (≥50%) reflects our current level of performance and a commitment not to let awareness decline as our digital presence evolves.

The restoration time accuracy target (≥30%) reflects an improvement on our FY24–FY26 average of approximately 25%, recognising that this is a relatively new service measure and that improvement will require systems and process development.

The small generation connection target (100% within 10 business days) is aligned to requirements under the Electricity Industry Participation Code 2010.

5.1.7.2 What our service measures mean

We derive both customer experience targets from our annual independent customer surveys, assessing satisfaction across multiple dimensions. A score above 8 out of 10 represents strong performance and indicates customers are generally satisfied in their interactions with us.

Our website provides access to outage information, connection processes, safety guidance, and other customer resources. We aim to improve awareness of our website over time, so more customers know where to find accurate information and support.

Restoration time accuracy measures how closely our communicated estimated restoration times match the actual restoration times. Based on our recent performance, we estimate that approximately 25% of communicated restoration times have been within ±30 minutes of actual restoration times. We are working to improve how we record information to accurately produce this service measure. Over time we will improve our ability to provide customers with more reliable restoration times.

Small generation connection timeframes reflect our performance in processing applications for rooftop solar and other small, distributed generation owned by customers.

5.1.7.3 Our approach to customer service

We provide multiple contact channels to recognise the different preferences of customers, including phone, email, website forms, social media, and in-person visits by appointment.

Our commitment to accessibility ensures all customers can engage with our services effectively. Website content is designed for readability and accessibility.

Behind the scenes, we have improved our processes through a customer relationship management system for better tracking, streamlined connection processes for standard requests, clear timelines and status updates, and regular staff training on customer service best practices.

During major events, when contact volumes rise, we put in action event communication plans, including enhanced website functionality, proactive social media updates, pre-scripted messaging, and close coordination with emergency management agencies.

5.1.8 Our energy transition service measures and targets

We are committed to enabling New Zealand's energy transition by facilitating distributed energy resources, supporting electrification, and developing smarter, more flexible network operations.

5.1.8.1 Our energy transition service measures and targets

To ensure we achieve this commitment we have developed three new service measures, which we will begin reporting against in FY28, with monitoring data collected in FY27 to help establish and confirm targets to FY36.

Table 5.13 New energy transition performance service measures

Service measure	Annual target to FY36
Number of commercial and industrial customers supported to understand their flexible capability and report on outcome/learnings	≥ 10 per year
Notification of forecast constraints shared with flexibility service providers	≥ three years before expected constraints at sub-transmission and zone substation level; ≥ two years before expected constraints at 11 kV and low voltage level
Maximum duration (hrs/ICP) distributed energy resource export curtailment, per residential customer with DER, due to network constraints	To be determined

The commercial and industrial flexibility support target of 10 customers per year is set to ensure that meaningful engagement can occur and learnings captured, including understanding the barriers to implementation during this initial learning phase.

The constraint notification timeframes are set in line with our non-network solution planning criteria outlined in our Network Development Strategy. It excludes work in response to customer-initiated requests (e.g. if we receive in a customer request for a new connection that requires a zone substation upgrade in the following year, this is not included in the target measure).

The DER export curtailment service measure will begin as a monitoring exercise in FY27, with a formal target to be set from FY28 once a baseline is established and aligned with our Congestion Management Policy.

5.1.8.2 What our service measures mean

Customer flexibility support recognises that some commercial and industrial customers have loads that can be flexible, e.g. shifted in time, reduced during peaks, or otherwise adjusted. Understanding and enabling this flexibility provides value to participating customers, and to all other customers, by deferring or avoiding traditional network capex investments. Our target of 10 customers per year reflects a learning phase where we develop capability and understand barriers.

Constraint notification timeframes measure how far in advance we communicate forecast network constraints to flexibility service providers. Early notification enables those providers to develop and deploy solutions that might defer or avoid traditional upgrades.

Distributed energy resource export curtailment measures the extent to which we limit customers' ability to export generation, e.g. from solar equipment, due to network constraints. Some curtailment may be necessary to manage voltage or thermal constraints; excessive curtailment would reduce the value of customer investments. We will start tracking this duration in FY27 to establish a baseline before setting a target for FY28.

5.1.8.3 Our approach to supporting the energy transition

We are enabling rapid growth in distributed energy resources through streamlined connection processes, clear technical standards, and proactive network upgrades. We actively participate in industry innovation initiatives and collaborate with the Electricity Authority, other distributors, and technology providers to develop solutions that enable the energy transition while ensuring the transition benefits all customers.

5.1.9 Discontinued service measures

Six service measures that appeared in our 2024 AMP are not being carried forward through the current AMP period. The year of final reporting and the reasons for their removal or replacement are outlined below.

Table 5.14 Discontinued service measures

Service measures (as it appeared in the 2024 AMP)	Reason for discontinuation or replacement	Last year for reporting
Power quality: number of escalated customer complaints	Instead of counting escalated complaints, we are improving the usefulness of this service measure by focusing on how quickly these issues are resolved and how promptly we respond to customers when a complaint is logged.	FY27
Power quality: number of proven harmonics or distortion complaints	This is a subset of customer complaints, and details of the specific power quality issue will be recorded internally. Separate reporting in the AMP is not required.	FY27
No. of breaches in the Security of Supply Standard – Transpower’s GXPs	These service measures no longer provide meaningful insight into customer service improvements, as our Security of Supply Standard now serves as a guide rather than a strict compliance requirement.	FY25
No. of breaches in the Security of Supply Standard – Subtransmission		
% of transformers monitored across Orion’s LV network	When this service measure was first introduced, we didn’t have access to smart meter data. Smart meters are now widely installed, and we have secured operational data access to approximately 90% of these meters (see Section 9.3.1 for details). However, contractual and commercial barriers mean we still rely on distribution transformer monitoring to fill visibility gaps across the network. This service measure therefore remains relevant, though its importance has reduced compared to when it was first introduced.	FY25

Table 5.14 Discontinued service measures		
Service measures (as it appeared in the 2024 AMP)	**Reason for discontinuation or replacement**	**Last year for reporting**
Network-led flexibility: capacity available through hot water load control	While we will continue to monitor this internally, for AMP reporting we are introducing broader flexibility service measures that better reflect our support for the energy transition. See the service measures under Section 5.1.8.	FY25

5.2 Other performance related considerations

5.2.1 Notification of planned and unplanned interruptions

Clear and timely communication about power outages is essential for customers to plan activities and manage the impact of interruptions. When we need to interrupt supply for planned maintenance, asset replacement, or network improvements, we provide advance notification. When we must reschedule planned outages, we notify affected customers as quickly as possible. We only cancel or reschedule planned work when necessary. For instance, when the following occur:

- severe weather forecasts making work unsafe or ineffective
- discovery of unexpected safety hazards during preparation
- operational emergencies requiring urgent response
- equipment delivery delays beyond our control.

Unexpected faults require different communication approaches with an emphasis on timely provision of information. When an unplanned outage occurs, we:

- publish outage information on our website, including location, extent, number of customers affected, the cause if known, and estimated restoration time
- we send registered customers text messages and/or email notifications. Updates are sent automatically as the status changes
- post on social media widespread outages or outages of public interest.

Customers want to know when power will be restored. It can be challenging to provide accurate estimates, particularly early in an outage when we may still be investigating the cause of a fault or travelling to the location. Our approach is to provide estimates based on typical restoration times for similar fault types and then update these estimates as we gain better information about the fault.

For extended outages lasting longer than 24 hours, typically outages following major storms or earthquakes, we maintain communications throughout the outage. We also provide:

- information about customer support services available
- advice on safety and managing without power
- contact information for urgent concerns
- clear explanation of why some areas are restored before others. We prioritise restoring power to the greatest number of customers first, to critical facilities like hospitals, and to vulnerable customers.

During major outages affecting large numbers of customers, we activate enhanced communication protocols and activities, potentially in coordination with the National Emergency Management Agency (NEMA) and other life-line organisations.

5.2.2 Complaint resolution process

We take complaints seriously and have established processes to ensure they are handled fairly, promptly, and transparently. When we receive a complaint:

- We acknowledge it as soon as possible. Depending on the nature of the complaint our acknowledgement may include information on an expected timeframe for a full response from Orion and our dispute resolution process.
- We assess the nature of the complaint and assign it to an appropriate experienced person to investigate and resolve. Investigation may involve such matters as gathering relevant information, reviewing records, undertaking site visits if required, and potentially consult with technical experts for complex matters.
- We discuss our findings with the complainant once the investigation is complete, and report on any corrective actions we are undertaking.

Customers who are not satisfied with the outcome of our internal process can also contact:

- Utilities Disputes, which is an independent dispute resolution service for electricity customers and free for customers to use. Website: https://www.udl.co.nz, Phone: 0800 22 33 40.
- Other external bodies, including: the Electricity Authority, the Commerce Commission, or the Privacy Commissioner, depending on the nature of the complaint.

Although it is disappointing to receive complaints, we recognise that complaints provide valuable feedback to help us improve. They can identify network performance problems, process inefficiencies, communication gaps, and the need for improved training. Our goal is not only to resolve individual complaints but to systematically improve our performance, reducing the incidence of issues and improving outcomes for all customers.

6

6. Asset Management System

Our Asset Management System (AMS) provides the foundation for how we plan, deliver, operate and continuously improve our assets and network. It connects our organisational purpose, regulatory obligations, focus areas and investment priorities with our day-to-day asset decisions through Asset Management Policy, defined roles and responsibilities, and structured asset lifecycle management processes.

A key prerequisite of fulfilling our asset management objective of being an operationally excellent distributor is the alignment of our asset management strategies to customer and stakeholder expectations and risk profiles. To support this alignment, we are working to more closely align our AMS with the ISO 55000 series of standards. These internationally recognised standards provide a strong benchmark for good industry practice.

This section outlines our systematic approach to asset management and describes how these components work together to ensure we deliver safe, reliable electricity services at the lowest total lifecycle cost.

6.1 Asset management system

The following subsections describe the scope, components, documentation, controls, and review processes that comprise our AMS.

6.1.1 Scope of the AMS

As an asset management business, all our organisational activities either directly or indirectly contribute to asset performance and customer outcomes. However, our AMS is primarily focused on the people, processes, and systems directly involved in managing network asset performance and delivery. The scope of our AMS includes:

- All electricity distribution network assets owned and operated by Orion
- All supporting assets, such as protection and monitoring equipment, SCADA systems, and communications infrastructure
- Non-network assets including buildings, vehicles, and ICT systems that support network operations
- Asset Management, Network Portfolio, Network Delivery, Operations, Engineering, Procurement and Asset Information teams
- Service delivery partners and service providers contracted for network design, construction, maintenance, and operations support.

Supporting functions, such as Finance and People and Capability, provide enabling services to the AMS but are not considered core components for the purposes of ISO 55000 alignment.

6.1.2 Components of the AMS

The AMS comprises several interconnected components that work together to ensure our asset management activities support delivery of The Orion Group Strategy and align with good practice. These components are shown in Figure 6.1 and are underpinned by governance and accountability structures that ensure clear decision-making and oversight across the system:

- **Strategic direction** is established through community engagement and stakeholder input, which feeds into The Orion Group Business Plan and Statement of Intent. Our Strategic Asset Management Plan (SAMP) and Asset Management Policy translate this strategic direction into asset management priorities, informed by our Future Energy Scenarios that anticipate how the network will need to evolve.

- **Network and asset planning** translates high-level strategic direction into Asset Class Strategies and the Network Development Strategy, supported by economic analysis and the preparation of investment cases. Work plans are then created and prioritised taking account of our risk management framework and data held in our asset information systems.
- **Portfolio management** sequences and resources the approved works programme, guiding how we procure equipment and contract services to deliver the investment plan.
- **Network delivery and operations** executes the work programme through capital project delivery, maintenance activities, and day-to-day network operations.
- **Measurement and feedback** tracks asset, cost and work performance against our asset management objectives, providing the information needed to assess outcomes and inform future planning.
- **Evaluate and improve** assesses the health and maturity of the AMS, supported by our Asset Management Improvement Plan and regular audits and reviews.
- **Enablement** provides the leadership, people capability, competence and corporate knowledge that underpin effective delivery across all components of the AMS, supported by integrated information systems, data platforms, advanced analytics and AI and machine learning capabilities that enable better asset decisions over time.
- **Core business capabilities** comprise the engineering standards, risk management frameworks and corporate policies that set the operating parameters for asset management activity.

Figure 6.1 Orion's asset management system

6.1.3 Asset management documentation

Our AMS is supported by a hierarchy of controlled documents. These documents are organised in a structure that provides clear-line-of-sight from strategic objectives to operational activities:

- **Strategic documents** establish organisational direction and asset management priorities (Group Business Plan, Statement of Intent, SAMP)
- **Policy documents** translate strategic direction into guiding principles for asset management activities, including our Asset Management Policy. Our AMS also interfaces with Board-approved supporting policies including Cyber and Security, Environmental, Risk, Privacy, Procurement and Safety, Health and Wellbeing.
- **Planning documents** provide detailed strategies and plans for specific portfolios and programmes (Investment Decision Framework, Business Case Template, Risk Framework, Asset Class Strategies, Network Development Strategy, supporting strategies)
- **Implementation documents** guide day-to-day execution (this AMP, annual works programmes, design standards, equipment specifications, maintenance procedures).

We maintain these asset management-related documents in a controlled SharePoint environment with defined review cycles appropriate to each document type.

6.1.4 Audit and review of the AMS

We undertake regular audits and reviews to assess the effectiveness of our AMS and identify improvement opportunities. Further details on our continuous improvement approach, maturity assessment processes, and improvement initiatives are provided in Section 18 – Asset management improvement.

We are beginning to track, and report to our Integrated Leadership Team and Board, the health of our AMS by monitoring the status of our asset management objectives (outlined below) against key performance indicators. In the future, this systematic monitoring and reporting will support our alignment to the ISO 55000 series and ensures ongoing accountability to our key stakeholders.

6.2 Asset Management policy

Our Asset Management Policy ensures that our asset management practices and systems are aligned with, and support, the delivery of The Orion Group Strategy, as outlined in Section 3 - Who we are.

The Policy translates our three focus areas into key principles for asset management:

Safe, reliable, resilient network

1. Prioritising the safety of our people, including staff, service delivery partners, and the public.
2. Using data-driven and risk-based approaches to ensure our investments deliver the best value.
3. Designing and building a future-fit network through continual innovation and efficiency improvement.

Utilised and accessible network

1. Deploying smart technologies and data analytics to maximise the utilisation of our existing network and enable participation through demand-side management

Our community

1. Align our supporting asset management strategies with customer priorities.
2. Working closely with key stakeholders to test and validate the Future Energy Scenarios and regional energy plan.
3. Actively reducing our environmental footprint.

We formally review the Policy every three years to assess its effectiveness and relevance, adjusting as necessary to meet the evolving needs of our community and focus areas.

6.3 Asset management objectives and supporting strategies

In our SAMP, we have established seven asset management objectives to continue improving our asset management practices, as captured in Table 6.1. These objectives define our priorities for managing assets over their lifecycle to deliver long-term value, and ensure work across Orion stays connected and focused.

Table 6.1 Orion's asset management objectives and focus areas

Policy	Asset management objective	Asset management focus area
Safe, reliable and resilient network	**Safety** *Reduce the potential for network assets to cause harm to people to So Far As Reasonably Practicable (SFARP) levels.*	**Safety in network design and operations**: Ensure safety is embedded throughout asset design, construction, operation, and decommissioning. **Risk mitigation through targeted interventions**: Proactively replace or manage assets that present safety hazards, e.g. arc flash risks, legacy switchgear, unsafe pole foundations. **Public and workforce safety enhancement**: Invest in systems and practices to protect workers and the public, including improved site security, isolation practices, and incident prevention.
	Reliable Network *Improve (in localised areas) or maintain reliability, as measured by SAIDI and SAIFI.*	**Renewals and reinvestment to maintain reliability**: Focus lifecycle investment on renewal of deteriorating assets, particularly where failures could impact reliability metrics. **Targeted reinforcement based on reliability risk**: Prioritise reinforcement where customer reliability outcomes are at risk of decline, guided by our HV Security of Supply Guide and localised customer preferences. **Smart outage management**: Improve planned outage coordination and outage response systems to minimise both planned and unplanned customer interruptions.
	Resilient Network *Strengthen the 4 Rs (Reduction, Readiness, Response, and Recovery) to minimise the impact on customers following a High Impact Low Probability (HILP) event.*	**Resilience in network design and planning**: Embed resilience into network renewals and expansions by strengthening interconnection, upgrading to modern standards, identifying single point of failure and considering climate adaptation. **Targeted asset lifecycle renewals for resilience**: Prioritise renewal and reinforcement of assets exposed to rare but high-impact events, e.g. severe weather, flooding, wildfires, and earthquakes. Focus investment on hardening vulnerable parts of the network, including replacing legacy subtransmission cables, strengthening structures, and relocating or redesigning exposed assets. **Emergency response readiness**: Maintain strategic stock of critical spares, formalise contingency planning, and enhance operational response protocols to restore service faster following major events.
	Operational Excellence *Enable safe, reliable, and cost-effective electricity services by developing our people, systems, and processes to optimise asset performance, cost, and risk.*	**Data-driven asset management**: Improve asset data quality, standardisation, and use in investment decisions. **Continuous improvement and governance**: Strengthen governance frameworks, invest in people capability, and create clear feedback loops from delivery to planning to support learning and continuous improvement.

Table 6.1 Orion's asset management objectives and focus areas

Policy	Asset management objective	Asset management focus area
		Innovation integration: Embed learnings from trials (e.g. grid visibility tools, advanced analytics) into standard operational processes to optimise maintenance, outage response, and investment planning. **Market and commercial readiness**: Ensure asset management processes can operationally support non-network services, DER participation, and contracted non-wires solutions through planning and operational protocols.
Utilised and accessible network	**Powering Today, Enabling Tomorrow** *Support regional growth by maximising capacity through data and digital tools and enabling customer participation.*	**Timely and scalable capacity investment**: Reinforce the network in step with demand growth and electrification, using forecasting, customer engagement, and risk analysis to ensure investments are timely and justified. **DER enablement**: Develop hosting capacity tools, active DER management systems, and appropriate commercial arrangements to facilitate safe, scalable integration of customer-owned generation and flexible loads. **Technology-driven capacity expansion**: Trial and adopt non-wires technologies such as dynamic line rating, battery energy storage, and network visibility systems to support capacity growth without relying solely on physical reinforcement.
Our community	**Customers and Community** *Enhance communication with customers, and their experience when interacting with us.*	**Improved customer communication**: Develop clear, timely, and customer-focused communication processes, especially around planned outages, new connections, and project impacts. **Enhancing customer understanding of network services**: Provide customers with visibility into Orion's investment approach and reliability performance, supporting trust and transparency. **Community-focused project delivery**: Minimise disruption through coordinated works planning and engagement with councils, communities, and other utilities.
	Environmental Sustainability *Facilitate reduction in polluting consumables or emissions, either for us or the community.*	**Low-emissions infrastructure**: Prioritise materials and designs that reduce embodied and operational emissions, e.g. lower-carbon concrete, recycled poles, SF_6-free switchgear. **Waste minimisation and responsible disposal**: Improve end-of-life asset disposal and recycling practices to reduce waste to landfill and mitigate environmental impacts. **Supporting the net-zero transition**: Enable electrification and distributed generation to support regional decarbonisation goals, aligning Orion's infrastructure development with broader sustainability outcomes.

Each objective has been informed by three key inputs:

1. **What matters to our customers**: through extensive engagement, including Powerful Conversations, Customer Perceptions Surveys, and ongoing consultation as part of our CPP Application, we have listened to what customers expect from us. Their consistent messages around safety, reliability, resilience, affordability, and support for decarbonisation have directly informed our objectives.
2. **The risks we face across our network**: our network operates in a dynamic environment with evolving risks from ageing infrastructure, climate-related change, natural hazards, and rapid technological change. Our objectives ensure we address these risks systematically and maintain appropriate levels of safety, reliability, and resilience.

3. **The capabilities we need as an organisation**: delivering good asset management requires capable people, systems, processes, and data. Our objectives recognise that operational excellence and continuous improvement in these foundational capabilities are essential to achieving outcomes for customers.

Our asset management objectives also reflect our evolving operating environment, including climate-related impacts, affordability pressures, and the shift towards digital and data-driven ways of working. The objectives provide clear direction while remaining flexible enough to adapt as circumstances change.

6.3.1 Supporting strategies

Our asset management objectives are supported by a suite of strategic documents that provide detailed direction for specific areas of asset management. These strategies ensure our objectives translate into actionable plans across the asset lifecycle:

- **Network Development Strategy**: guides our approach to identifying network constraints, assessing them against demand forecasts and risk thresholds, and translating them into timely investment decisions that are aligned to our network architecture and Security of Supply Guide. Further details can be found in Section 10 – Network development approach.
- **Asset Class Strategies**: provide asset class objectives, and lifecycle management approaches for each of our network asset fleets. These strategies ensure strategic alignment with our operational excellence objective by documenting our whole of life asset lifecycle management from acquisition through to disposal. Further details can be found in Section 14 – Asset portfolio renewals.
- **Network Transformation Roadmap**: provides foresight and direction for adapting our network to future demand, technology shifts, and customer needs, ensuring we remain ready for tomorrow's challenges. Further details can be found in Section 9 – Transforming our network.
- **Flexibility and Markets Development Roadmap**: sets out how we will transition to supporting customer participation in demand-side flexibility and market-based solutions, enabling New Zealand's energy transition while managing network costs. Further details can be found in Section 9.
- **Innovation Strategy**: sets out how we explore, learn and implement new solutions for the long-term benefit of customers. It focuses on building the capability to adapt and lead through change as the energy system transforms. Guided by principles of collaboration, experimentation and learning, we aim to test and scale solutions that enhance customer value, resilience and long-term affordability. Further details can be found in Section 9.5 – Innovation practices, and on our website: https://www.oriongroup.co.nz/your-energy-future/innovation.
- **Data and AI Strategy**: establishes our framework for becoming a data-driven organisation, supporting our operational excellence objective through better insights and decision-making. Further details can be found in Section 8 – People and technology.
- **People Strategy**: focuses on building, retaining, and developing the workforce capability needed for modern asset management, underpinning our operational excellence objective. Further details can be found in Section 8.
- **Sustainability Strategy**: outlines how we will improve our sustainability maturity over time. The strategy is aligned with The Orion Group's Strategy and our asset management objective on environmental sustainability.
- **Vegetation Management Strategy**: guides our approach to managing vegetation risks to achieve our safety, reliability and resilience asset management objectives. Further details can be found in Section 13 – Operations and maintenance.

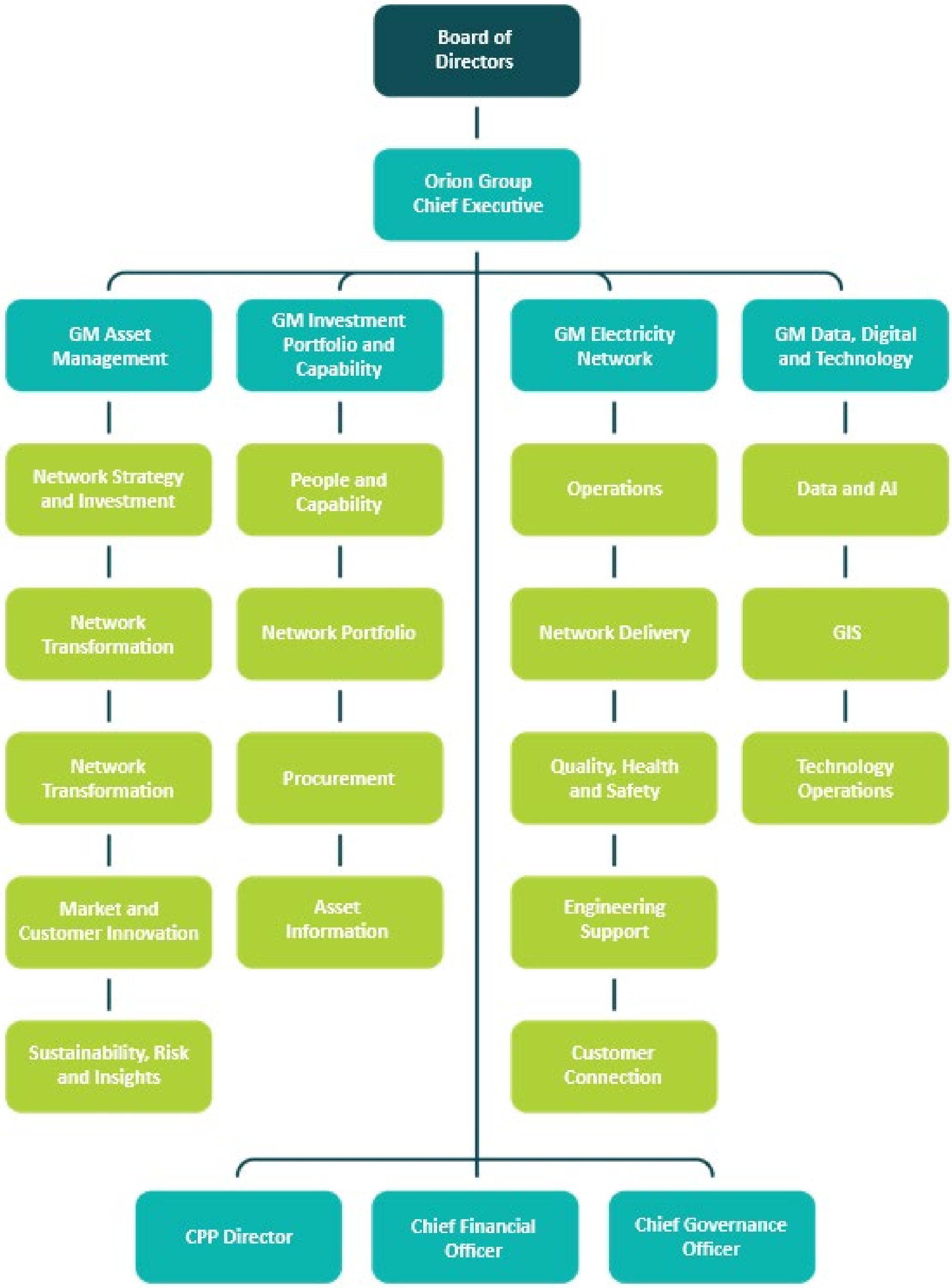
These strategies work together to ensure our asset management activities support delivery of The Orion Group's Strategy, align with good electricity industry practice, and deliver value for customers across the full asset lifecycle.

Additional strategies are planned for development in 2026 and 2027 to further strengthen our asset management framework. These include the Reliability Strategy, Resilience Strategy (and review of the associated Critical Spares Strategy), and the Community Energy Services Strategy.

6.4 Asset management roles and accountabilities

Effective delivery of our asset management system requires clear accountability and coordination across all levels of Orion. Our governance structure ensures that strategic direction, investment decisions, and operational delivery are aligned with our asset management objectives and customer expectations. Figure 6.2 displays our asset management system organisational structure.

Figure 6.2 Orion's organisation structure



6.4.1 Internal restructure for integrated planning and delivery

In 2025, we restructured our asset management business unit to better support integrated planning and delivery. Network development and asset renewal planning now both report to the Head of Network Assets (who reports to the GM Asset Management), supported by dedicated Asset Manager roles focused on specific asset groups. We have also established a separate Portfolio function to coordinate work across different investment portfolios.

This revised organisational structure enables clear accountability and line-of-sight from planning through to delivery. It allows us to plan work holistically, bundle projects together where appropriate, and coordinate across related asset types to minimise customer interruptions.

6.4.2 Outsourced asset management components

Orion contracts all network design, construction, renewal, and maintenance activities to Service Delivery Partners (SDPs). This outsourcing model allows us to access specialist capabilities and scale resources to match workload variations while retaining strategic control and core asset knowledge in-house.

Orion maintains a hybrid model for field operations. We have an in-house team of network field operators who are our first responders to power outages and emergencies. This team makes the network safe following events, undertakes switching to restore power, performs minor repairs, and manages our generator fleet. Network control, monitoring, and real-time operations are managed through our Network Control Centre.

All other network construction, renewal, and maintenance work including operations for work is undertaken by SDPs under contract to Orion. Our network portfolio and procurement teams are responsible for planning, designing, programming, and awarding works to SDPs. Our network delivery team manages execution in partnership with SDPs, providing oversight and coordination. This structure provides clear accountability and line-of-sight from planning and procurement through to field delivery.

Further details on our delivery model, and SDP management are provided in Section 17.

6.4.3 Roles and responsibilities

Table 6.2 outlines the key governance roles and responsibilities for asset management.

Table 6.2 Orion's asset management governance

Role	Responsibilities
Board of Directors	• Formally reviewing and approving key policies, including the Asset Management Policy. • Approving the overall strategic direction for the business, through The Orion Group Business Plan and Statement of Intent. • Overseeing commercial performance, business plans, and budgets that influence how we invest in, manage, and dispose of network assets. • Reviewing reports of asset management outcomes and asset performance and providing associated feedback and guidance. • Providing challenge on affordability, risk and customer outcomes. • Assessing and approving business cases beyond CEO delegated authority. • Reviewing and certifying the AMP in accordance with regulatory requirements.
Integrated Leadership Team (ILT)	• Ensuring activities align with asset management objectives and metrics and allocating resources to enable successful delivery. • Participating and providing feedback in the investment approval process for business cases and forecast challenge sessions. • Escalating larger investments for CEO or Board approval as per the Delegated Authority Policy. • The GM Asset Management is accountable for the development of the AMP, the preparation and delivery of our Strategic Asset Management Plan, and for monitoring and reporting on the overall health of the AMS.

Table 6.2 Orion's asset management governance	
Role	**Responsibilities**
AM Excellence Steering Committee	• Approving new Asset Management Improvement Plan initiatives and any material changes to scope or priorities. • Monitoring AMIP delivery progress and holding the programme accountable to planned timelines. • Tracking benefits realisation against expected outcomes. • Reviewing AMS performance, including effectiveness of key processes. • Approving key asset management strategies and frameworks before they are published. • Escalating significant risks, issues or decisions to ILT or the Board as required.
Advisory Groups	• Brings together senior leaders to guide programme direction, validate strategic alignment, and approve key decisions. • Examples include the Network Transformation Advisory Group and the Flexibility and Markets Development Advisory Group.
Working Groups	• Support the development of investment documents, review and refine investment options. • Validate technical assumptions and delivery feasibility. • Assess risks and dependencies. • Approve recommended solutions before they progress to ILT and Board approval for inclusion in the AMP and procurement or delivery planning.

6.5 Communication and participation in asset management

Effective asset management requires clear communication and active participation across all levels of Orion and with external stakeholders. We maintain structured processes to ensure our supporting asset management strategies, objectives, and plans are well communicated and that stakeholders can contribute effectively to delivering outcomes for customers. Table 6.3 summarises our communication channels and participation mechanisms for key stakeholder groups.

Table 6.3 Orion's asset management communication and participation		
Stakeholder group	**Communication channels**	**Participation mechanisms**
Customers and Community Stakeholders Objective: Align investments with customer priorities and willingness to pay	• Annual AMP publication and stakeholder engagement. • Customer engagement through Powerful Conversations, Customer Perceptions Survey, and other channels described in Section 4 – Customers and stakeholders.	• Customer engagement in CPP and AMP investment planning through consultation on priorities and trade-offs.
Suppliers, service delivery partners (SDPs) and other contractors Objective: Ensure delivery capability and maintain strong partnerships	• Supplier, SDP, and other contractor engagement through delivery planning and procurement processes.	• SDP involvement in early delivery planning and deliverability reviews.
Internal teams Objective: Foster collaboration and ensure line-of-sight across functions	• Regular cross-functional meetings between Asset Management, Engineering Support, Portfolio, Delivery, and Operations teams to support efficient and cost-effective delivery. • Advisory Groups and Working Groups • ILT Steering Committees for strategic oversight and decision-making. • All staff communications on major asset management initiatives and performance.	• Cross-functional teams in option development and investment decision-making. • Staff participation in asset management improvement initiatives.

Shareholders Objective: Ensure asset management supports shareholder value and community outcomes	• Statement of Intent • Annual report • Management and Board reporting	• Strategic direction through SOI approval and ownership expectations
Regulators Objective: Demonstrate compliance and transparent asset management	• Regulatory engagement through responding to consultations, and our AMP submission and compliance processes.	• Participation covered through formal regulatory processes.

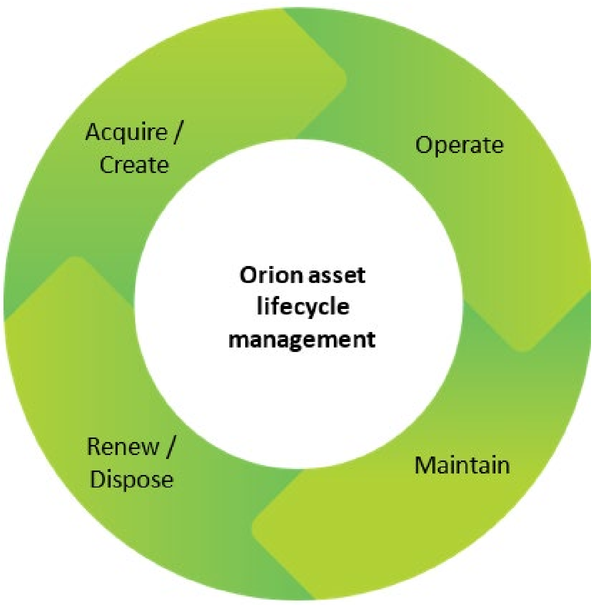
6.6 Overview of asset lifecycle management

Effective asset management requires a holistic approach that considers the full asset lifecycle. Our approach to lifecycle management seeks to ensure we deliver a safe, secure, and reliable electricity service at lowest total lifecycle cost to the community of Central Waitaha Canterbury, today and in the future.

As part of our business-as-usual asset lifecycle management processes, we have developed updated investment plans for the 10-year AMP period. These plans, outlined in Section 12 – Network development programme, and the Asset Portfolio Management Chapter (Sections 13 – 15), reflect updated asset information and changes to our forecasting approaches that reflect our ongoing improvements to asset management practices.

Our asset management approach reflects the overall lifecycle of the assets we manage: acquire/create, operate, maintain, and renew/dispose. Effectively managing assets across their full lifecycle requires close coordination of decisions and activities across Orion. Each of the stages of our approach are set out in more detail below.

Figure 6.3 Orion's asset lifecycle management approach



Our lifecycle management approach is guided by our Strategic AMP, the seven asset management objectives and supporting focus areas, and the supporting strategies outlined in Section 6.3. These objectives and focus areas provide a clear line of sight from our strategic intent to tangible outcomes across the asset lifecycle, guiding specific investment decisions.

6.6.1 Acquire/create

This stage involves procuring or developing new assets, such as new circuits, feeders, or zone substations, to meet growth, reliability, resilience or safety needs. Several interrelated activities in this stage are used to develop our capital investment plans, including identifying network constraints, evaluating different options, procurement, negotiating with suppliers, and finally purchasing or constructing the asset.

Decisions made during planning have long-term implications for our network assets over their lifecycle and must be made systematically and transparently to ensure investments deliver the right service, at the right cost, and within acceptable risk tolerances.

6.6.1.1 Network development planning

Identifying network constraints and determining required interventions begins with assessing the risk of asset failure and network performance gaps. As part of our investment proposals, when determining what work we need to do, we consider the following:

- safety and other regulations
- the health and criticality of assets
- any identified performance issues
- current and future obsolescence issues
- the required level of service to meet customer needs
- the capacity of our network and assets needed to meet the identified level of service.

See Section 10 for further details on our network development approach.

6.6.1.2 Non-network solutions

When our network becomes constrained, investing in new infrastructure may not always be the most cost-effective option to relieve the constraint. Non-network solutions can enable deferral of much larger capex that is usually associated with network solutions. These solutions can provide value in terms of lower lifecycle costs, while enabling us to defer investment decisions when there is uncertainty, such as with future load growth.

Alternative approaches to traditional renewals or replacements include:

- **Demand-side management**: altering customer behaviour through incentives, pricing signals, or direct load control to reduce or shift demand away from peak periods.
- **Distributed energy resources**: including distributed generation, battery storage, and electric vehicles that can provide flexibility services to manage network constraints.
- **Flexibility services**: contracting with third parties to provide demand response or generation capacity during constrained periods.
- **Cost-reflective pricing**: pricing structures that incentivise customers to modify their usage patterns to reduce network peaks.

We consider non-network solutions as part of our options analysis for network development projects, particularly where they offer the potential to defer or avoid larger network investments. Our planning and approval process for larger projects includes formal consideration of non-network solutions where these are technically feasible and economically viable.

For renewal projects, non-network solutions are generally not a feasible substitute. Where asset renewal is driven by age, condition, or performance deterioration, the underlying asset risk must be addressed through replacement or refurbishment. In these circumstances, non-network alternatives do not mitigate the safety, reliability, or compliance risks that drive these decisions. Accordingly, our expenditure projections for renewal asset management in Section 14 do not assume material deferral or substitution through non-network solutions.

6.6.1.3 Design and build

We use SDPs for designing and building assets. To guide them, we have established standards and specifications as outlined in Table 6.4.

Table 6.4 Orion's standards and specifications

Standard or specification	Purpose
Safety in design standard	Used by Orion and our SDPs to identify hazards that could exist throughout the complete lifecycle of assets from concept to disposal. The standard includes a hazard identification and risk assessment process which proposes elimination and control measures to be incorporated in the asset design for each identified hazard.
Design standards	To manage the health and safety, cost, efficiency and quality aspects of our network we standardise network design and work practices where possible. To achieve this standardisation, we have developed design standards and drawings that are available to our SDPs. Normally we only accept designs that conform to these standards; however, this does not limit innovation.
Technical specifications	We provide technical specifications to SDPs who work on the construction and maintenance of our network. These documents refer to the relevant codes of practice and industry standards.
Equipment specifications	We standardise equipment used to construct components of our network, where possible. To support standardisation we have developed specifications that detail accepted performance criteria for significant equipment in our network. New equipment must conform to these specifications. However, equipment that differs from our specification is considered if it offers significant economic, environmental, and operational advantages.

Our design approach emphasises standardisation through design standards and standard designs, helping to simplify delivery and achieve long-term network consistency. Safety in design is a key driver, with design reviews covering safety, technical requirements, and adherence to standards.

We use standardised designs and construction drawing sets across our key asset types. Our standardised designs and construction drawing sets cover substations, overhead distribution and equipment, underground distribution and equipment, and high voltage plant, and are maintained in our controlled document environment alongside design standards covering areas including overhead line design, underground cable design, distribution substation design, protection design, and earthing system design.

Standardisation is a deliberate cost efficiency strategy. By establishing minimum technical requirements and standard drawing sets for frequently constructed asset types, we can avoid repeated bespoke design effort across similar projects. When we develop standard designs, we consider factors such as likely cost-effectiveness, availability of materials and whether they have been approved for use on the network. SDPs can then adapt these standard drawings to suit site-specific conditions rather than designing from first principles, reducing design cost, improving delivery consistency, and lowering the risk of errors or non-conformance.

We also maintain equipment specifications covering significant asset categories including transformers, circuit breakers, ring main units, distribution cable, overhead line conductors, timber poles, and 400V switchgear.

Our Network Delivery team manages project execution in partnership with our SDPs, who undertake the physical design, construction, and commissioning work. Our internal teams are responsible for planning, programming, awarding works, and overseeing delivery to ensure projects are completed on time, to specification, and within budget. This includes managing scope and schedule, coordinating outage requirements, ensuring quality and safety compliance, and commissioning new assets with complete records.

6.6.1.4 Capex forecasting methodology

Capex forecasts use estimation approaches tailored to the type and scale of work, including volumetric estimates for high-volume repetitive programmes, tailored estimates for complex discrete projects, and base-step-trend approaches for certain categories of work.

Our approach to capex forecasting for lifecycle asset management activities are set out in Section 14 in the Asset Portfolio Management Chapter. Our approach to cost estimation is detailed in Section 16 – Our investment programme.

6.6.2 Operate

During this stage our assets are in-service providing electricity to customers.

Effective operation involves managing the performance of our assets to ensure they deliver their intended performance throughout their operational life. The way we operate assets can affect asset life and informs investment planning decisions.

Our Network Control Centre operates the network 24/7, managing real-time network configuration, switching, and event response to maintain reliable supply. Our in-house field operators are first responders to outages and emergencies, making the network safe and restoring supply where possible.

To ensure we operate our equipment and network safely, we have developed equipment operating instructions covering each equipment type. We also have operating standards for release of network equipment, commissioning procedures, system restoration, worker training, and access permit control.

Operational activities provide critical feedback to our asset management processes. Asset health data, performance monitoring, inspection results, and condition information gathered during operations inform our maintenance planning and renewal decisions. We seek continuous improvement by analysing operational events to avoid repeat incidents, such as those caused through human error, and sharing lessons learned with our SDPs and operational teams.

6.6.3 Maintain

This stage involves maintaining our assets to ensure they operate safely and reliably throughout their lifetime. This stage lasts for the duration of the asset's life (40-60 years for many assets) and is critical to maximising operating life, informing renewal decisions, and maximising value from assets.

Maintenance involves inspecting, monitoring and managing the deterioration of assets in service, in the case of a defect or failure or restoring the condition of assets. Adequate and timely maintenance helps detect and rectify issues before they escalate into larger problems, avoiding unexpected failures and more expensive reactive work.

Information gathered during maintenance activities provides feedback to improve our asset standards, planning processes, and renewal decisions.

Detailed maintenance approaches, inspection frequencies, and performance monitoring for each asset class are set out in Sections 13 – 15, in the Asset Portfolio Management Chapter and *Appendix G – Network maintenance approach*.

Our overall approach to planned and reactive maintenance is outlined in the table on the following page.

Approach	What this includes
Preventive maintenance	Asset inspections, condition assessments, and servicing. These are typically carried out on a regular basis in accordance with our maintenance standards. Recorded condition assessment data is used for analysis, forecasting and renewal planning. Defects and repair work also arise from preventive maintenance.
Corrective maintenance	Planned work arising from preventive maintenance, ad-hoc identification of defects, or to follow-up faults (following service restoration). Includes defect rectification, repairs and replacement of minor components to restore the condition of an asset. Failure to undertake this work can reduce reliability and increase safety risks.
Reactive maintenance	Work carried out in response to an unplanned event or incident that impairs normal network operation. Failure to undertake this work in a timely manner will adversely affect the service provided to customers and may increase public safety risk.
Vegetation management	Vegetation management involves monitoring vegetation growing in close proximity to our assets, liaising with landowners, and trimming and removing vegetation to keep it clear of network assets, especially overhead lines.

Table 6.5 Orion's planned and reactive maintenance approaches

6.6.3.1 Opex forecasting methodology

Opex forecasts use base-step-trend methodology for recurring activities, with adjustments for step changes and trends. For condition-driven and volume-driven work, we use historical patterns combined with asset population and defect rate forecasting.

Our approach to opex forecasting for preventive, corrective, reactive and vegetation management activities is set out in Section 13, while our approach to base-step-trend and cost estimation is detailed in Section 16.

6.6.4 Renew/dispose

The stage involves deciding whether to renew, refurbish, or dispose of assets as they approach the end of their useful life. All assets have finite functional lives that vary significantly depending on the particular asset concerned and the loading and environment they are exposed to. When assets approach end of life, we assess the appropriate response:

- Replacing assets generally involves using new, modern-equivalent versions that allow increased performance.
- Refurbishing assets involves extending asset life by partially, or completely, replacing individual components as necessary.
- The choice between full replacement and refurbishment depends on asset condition, availability of components, economic analysis, and strategic considerations.

Key triggers for renewal, refurbishment, or disposal include deteriorating asset condition, safety or environmental standards, obsolescence, or changes in required service levels.

Replacement decisions are driven by asset condition assessments, safety risks that cannot be economically managed through maintenance, obsolescence where spares are unavailable, economic analysis showing replacement is more cost-effective than continued maintenance, and strategic considerations such as network reconfiguration or capacity upgrades.

By considering the asset class as a whole and identifying commonalities in asset types, ages, and conditions, we can develop coordinated renewal plans that ensure a consistent approach and leverage economies of scale. This facilitates a more strategic approach, allowing us to prioritise replacements based on the relative criticality of the asset across the asset class rather than reacting to individual asset issues. Replacing assets proactively before failure helps us manage risk, minimise unexpected service disruptions, and avoid costly emergency repairs.

Renewal and refurbishment decisions for major assets are made through a structured business case and optioneering process that considers future demand forecasts and the optimum use of existing network capacity. Further detail on this approach is provided in Section 14.

Our renewal and disposal strategies are documented in the Asset Portfolio Management Chapter (Sections 14 – 15).

6.6.4.1 Innovation in asset renewals

While innovation and new technologies more commonly influence network development decisions (where they can enable new capacity or defer network reinforcement), they play a more limited role in asset renewal programmes. Asset renewals are primarily driven by deteriorating condition, safety risks, and obsolescence where replacement or refurbishment is required regardless of technological advancement.

However, innovation can influence renewal timing and approach in specific cases. Improved asset condition monitoring technologies (such as AI-assisted analysis of drone footage to identify defects) can help optimise renewal timing by providing better visibility of actual asset condition rather than relying solely on age-based assumptions. Similarly, advances in refurbishment techniques or component replacement options may extend asset life and defer full replacement.

Section 9.5 – Innovation practices outlines how we trial and evaluate new technologies that could enhance asset management decision-making.

6.6.4.2 Critical spares

We maintain critical spares for certain assets to enable rapid restoration of supply following major equipment failures. We identify critical spares based on procurement lead time, consequence of failure, likelihood of failure or damage, availability of alternative supply arrangements, and cost of holding spares versus risk of extended outages.

We currently maintain critical spares for power transformers, key switchgear components, subtransmission cables and accessories, and communications/SCADA equipment. This enables timely emergency renewals when assets fail unexpectedly, minimising extended customer outages.

6.6.4.3 Asset disposal

Asset disposal is required when an asset reaches the end of its useful life. When it comes time to dispose, we consider various options, such as reusing, selling, or recycling. The disposal process is planned to minimise environmental impact and recover as much value as possible.

Our SDPs are responsible for the disposal of redundant assets, equipment, hazardous substances and spill wastage. We closely collaborate with SDPs to ensure assets are disposed of safely and that hazardous materials are not passed on to any other party without our explicit approval.

7

7. Managing risk

This section outlines our approach to identifying, assessing, and managing risks across our network and business operations. It describes our risk management framework, governance and responsibilities, the key risk areas we face and how we manage them. It also explains our approach to building resilience and maintaining business continuity during major disruptions.

As outlined in Section 3 – Who we are, we operate in a dynamic and changing environment characterised by rapid population growth, on-going energy transition, significant natural hazard exposure including seismic risk, an aging asset base with deferred renewals, and expanding regulatory obligations.

Effective risk management is fundamental to achieving our strategic focus areas: maintaining a safe, reliable, and resilient network; enabling a highly utilised and accessible network; and supporting the wellbeing and prosperity of our community.

7.1 Risk management framework

Our risk management framework provides a systematic approach to managing risks and opportunities across Orion, ensuring consistent management of enterprise risks including the health, safety, and wellbeing of our staff, service delivery partners, and the public.

The framework is supported by three key governance documents that work together to guide risk management across Orion:

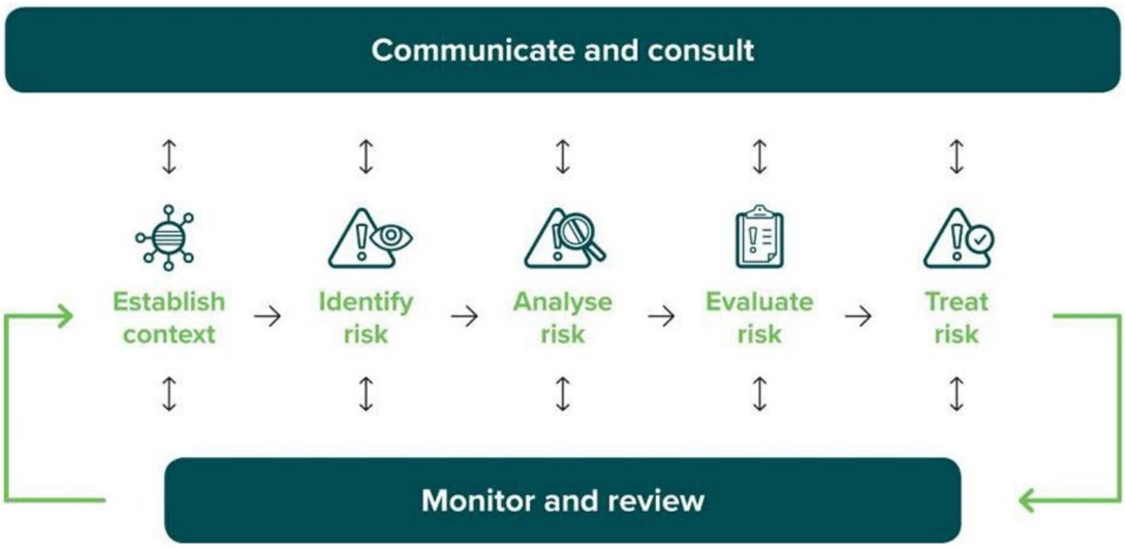
- **Risk Policy** defines the scope of risk management and sets out the core principles that guide all risk-related activities
- **Risk Framework** provides a complete view of our risk management system, identifying key components and assigning roles and responsibilities
- **Risk Guideline** provides practical guidance including the risk matrix, risk likelihood and consequence scales, risk appetite thresholds, and risk appetite statements approved by the Board.

Our framework is aligned with international best practice through ISO 31000:2018.

7.1.1 Risk management process

Figure 7.1 illustrates our risk management process. This process is embedded throughout Orion and applied at all levels, from strategic planning to day-to-day operational decisions.

Figure 7.1 Orion's risk management process



Our risk management framework and process enables us to identify and analyse long-term risks from events such as earthquakes, extreme weather, cyber-attacks, and other business disruptions. We can then develop appropriate mitigations to manage these risks in accordance with our Risk Policy, Risk Guideline, and governance processes.

The following subsections describe each element of our risk management process in more detail.

7.1.2 Establish context

Our context for risk management is informed by our operating environment, stakeholder expectations, regulatory obligations, and strategic objectives, as described in Section 3.

We have identified ten key risk areas that reflect our operating environment. These areas are systematically managed through our risk management framework and are described in Section 7.3.

7.1.3 Identify and analyse risks

Risk identification occurs across all levels of our organisation through multiple channels, including workshops with cross-functional teams, research into industry and wider business emerging threats, operational incident reviews, and strategic planning processes. We identify both immediate operational risks, such as asset failures, safety incidents, and service interruptions, and longer-term strategic risks, such as those associated with industry transformation, climate adaptation, and changing customer expectations.

Risk analysis involves developing an understanding of each risk's causes and sources, its likelihood and potential consequences, and the effectiveness of existing controls. We use our asset information management systems to support this analysis, drawing on asset condition data, failure mode knowledge, and historical performance information.

7.1.3.1 Assessing likelihood and consequence

We assess risks using a consistent likelihood and consequence assessment framework. Figure 7.2 illustrates our risk assessment matrix, which enables systematic assessment and prioritisation of risks based on their potential impact.

Figure 7.2 Orion's likelihood and consequence assessment matrix

Likelihood						
	Almost certain *It is expected to occur (e.g. more than once per year)*	Medium	High	Very High	Extreme	Extreme
	Likely *Will probably occur (e.g. once a year)*	Medium	Medium	High	Very High	Extreme
	Possible *Might occur at some time (e.g. once every three years)*	Low	Medium	High	Very High	Extreme
	Unlikely *Could occur at some time (e.g. once every ten years)*	Low	Medium	Medium	High	Very High
	Rare *May occur in exceptional circumstances (e.g. every 30 years)*	Low	Low	Medium	High	High
		Minor	**Moderate**	**Serious**	**Major**	**Severe**
		Consequence				

When assessing likelihood, we consider how often a task is carried out or how often a situation might occur, how and when consequences might occur and to whom, relevant evidence and history, and any new factors that might make history less relevant. Our likelihood ratings reflect credible scenarios, including residual risk that remains after implementation of our risk treatments and controls.

Our consequence ratings aim to reflect credible scenarios given our context and risk treatments, considering multiple dimensions including health and safety, business continuity, network interruption, reputation, financial impact, sustainability, environment and cultural heritage, and legal and regulatory compliance.

7.1.4 Evaluate risks

We evaluate risks using a consistent likelihood and consequence assessment, enabling us to prioritise risks based on their severity and potential impact. Table 7.1 outlines our risk escalation framework.

Table 7.1 Orion's risk escalation framework

Risk level	Response	Governance
Extreme	Immediate and decisive action	CEO ownership, monthly Board reporting, full treatment plan
Very high	Timely action to treat risk	General Manager (GM) ownership, Audit and Risk Committee oversight, bi-annual reporting
High	Manage and escalate as appropriate	Management and staff, escalate to GMs, guided by risk appetite
Medium/low	Manage at operational level	Escalate as appropriate

This escalation framework ensures that risks with the potential to significantly impact our ability to deliver services safely and reliably receive executive and Board-level attention, while lower-severity risks are managed through established operational processes.

7.1.5 Treat risks

Risk treatment involves selecting and implementing options to modify risks to acceptable levels. Figure 7.3 illustrates our five main risk treatment options and the decision-making considerations we apply when selecting the appropriate treatment.

Figure 7.3 Risk treatment options

We apply these treatment strategies depending on the nature and severity of each risk:

- **Avoid the risk** by deciding not to proceed with an activity or changing plans to eliminate the risk entirely
- **Treat the risk** through controls that reduce either the likelihood of the risk occurring or the consequences if it does occur
- **Transfer the risk** through insurance, contracts, partnerships, or risk-sharing arrangements
- **Accept the risk** where treatment costs outweigh potential benefits and the residual risk is within our risk appetite
- **Increase the risk** by taking calculated risks where opportunities for strategic benefit outweigh potential downsides.

Our Risk Guidelines provide protocols for risk treatment at Orion on the basis of both the risk scores and our risk appetite.

When selecting risk treatments, we exercise good judgement and consider the wider context, ensure our approach is reasonably practicable, consider opportunities that may arise, and evaluate wider factors and offsets. For each risk area, we develop treatment plans that are proportionate to the risk level and aligned with our strategic objectives. Section 7.3 describes the specific treatments applied to each of our key risk areas.

7.1.6 Monitor and review risks

Risk monitoring and review ensures our risk management remains effective and responsive to changing circumstances. We monitor risks on an ongoing basis through multiple channels including operational performance indicators, incident reviews, asset condition assessments, and regular risk assessment updates.

Risks are reviewed at different frequencies depending on their severity. Extreme and Very High risks receive monthly and bi-annual formal reviews respectively, as outlined in our escalation framework (Table 7.1). High, Medium and Low risks are reviewed quarterly or as circumstances change. All risks are reassessed annually as part of our strategic planning cycle.

Reviews consider whether risk treatments are achieving their intended outcomes, whether risk ratings remain appropriate given current conditions, and whether new or emerging risks require attention. Lessons from incidents, industry events, and changes in our operating environment are fed back into our risk assessments to ensure continuous improvement. The effectiveness of our risk management approach is also monitored through our governance structures, with regular reporting to the Audit and Risk Committee and Board as outlined in Table 7.2.

7.2 Risk management governance

Risk management is embedded throughout our governance and operational structures. Clear accountability ensures risks are identified, assessed, and managed effectively across all levels of Orion. Table 7.2 outlines the key roles and responsibilities for risk management at Orion.

Table 7.2 Orion's risk management roles and responsibilities

Role	Responsibilities
Board of Directors	• Governs and leads Orion's risk management. • Approves the Risk Policy. • Reviews key risk reports and emerging reports from management. • Receives tabled risk reports from Audit and Risk Committee.
Audit and Risk Committee	• Reviews and updates our Risk Policy and risk management framework. • Ensures risks are managed in accordance with our Risk Policy and Guidelines. • Reviews Orion's risk maturity, plans to improve maturity, and delivery against those plans.
ILT	• Governs and leads Orion's risk management alongside the Board. • Leads and promotes fit-for-purpose risk management for Orion. • Keeps the Board informed of key risks, including potential and emerging risks.
Enterprise Risk Lead	• Implements and maintains the risk management program, and assessing if all risks are managed effectively • Prepares key risk reports, emerging risks reports, maturity assessments and other reports to Board, Audit and Risk Committee and ILT. • Provides support for our teams where needed to ensure they have an up-to-date set of key risks. Conducts risk assessments where needed.
Risk owners	• Responsible for implementing mitigations and controls to ensure that risks are managed effectively.
All staff	• Responsible for identifying and escalating risks to their People Leaders and risk owners.

7.3 Key risk areas and how we manage them

We face a range of operational and strategic risks that could affect our ability to deliver on our asset management objectives. The key risk areas outlined below represent broad themes. Each theme contains multiple specific risks that are regularly monitored and managed through our risk management framework. Table 7.3 also summarises the severity of key risk areas, how we manage them, and where further details can be found in this AMP.

The risk profile shown for each risk area represents the residual risk rating; that is, the risk level after our current mitigation strategies and controls have been applied. This approach reflects our ongoing commitment to managing risks to acceptable levels while recognising that some level of risk will always remain in our operations.

Table 7.3 Orion's key risk areas and treatment approach

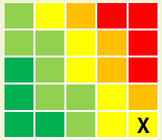
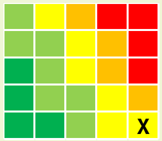
Risk area	Risk description	Risk profile (residual risk)	How we treat the risk area
Health and safety	There is a risk that one or more people, such as an Orion staff member or SDP, experience a fatality or serious health and safety incident while working on or near our network assets. There is a risk that a member of the general public, experience a serious health and safety incident that may result in fatality or serious injury, due to an incident at Orion assets in the public space.		Managing these risks are our highest priority. We maintain a safety-first culture through our comprehensive Safety, Health and Wellbeing programme, demonstrating our commitment to providing a safe and healthy workplace. This is supported by detailed Quality, Health & Safety playbooks covering Leadership & Governance, Critical Risk Management, Service Delivery Partners & a Person Conducting a Business or Undertaking (PCBU) Management, and Public Safety. Our safety in design, asset renewal and inspection and maintenance practices aim to identify and address safety risks. Section 13 and Section 14 provides further details on our approach.
Natural events and climate-related change	There is a risk that natural events, such as earthquakes, tsunamis, fires, floods, and severe weather, cause significant damage to our network and result in prolonged electricity outages. As outlined in Section 3, climate-related change is significantly increasing the likelihood and severity of fires, floods, and storm events.		We manage this risk through network design that enables rerouting when portions of our network are unavailable and asset improvement programmes that include mitigations to decrease impacts of natural events. See Section 7.4 – Resilience to High Impact Low Probability events for details on our application of the 4Rs Emergency Management approach (Reduction, Readiness, Response, Recovery). Section 14 outlines our approaches to hardening various assets against natural events, such as floods, fires, wind, and earthquakes. Section 10 describes our approach to increasing network diversity to maintain supply during natural events.
Equipment and technology failure	There is a risk of significant equipment or technology failure due to asset condition deterioration or human error, leading to an inability to supply customers for an extended period. Such events also pose potential health and safety risks.		We manage this risk through our Safety in Design Standard, which ensures that these considerations are built into all elements of the asset lifecycle, including asset data capture, failure mode knowledge base development, comprehensive inspection programmes, maintenance planning and delivery, and replacement investment case. Failure mode identification and escalation is built into our business processes and protocols. Our inspection programmes and asset renewal programme address asset condition risks. Section 14 describes our asset renewal programmes and inspection practices, while Section 13 outlines our maintenance practices that aim to identify and address asset defects before they result in failures.

Table 7.3 Orion's key risk areas and treatment approach

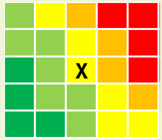
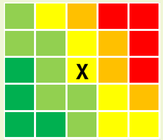
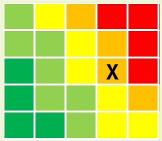
Risk area	Risk description	Risk profile (residual risk)	How we treat the risk area
Cyber and information security	There is a risk that Orion suffers a security breach, or that our data is shared inappropriately. This risk could impact business operations, assets, or the private information of customers staff or SDPs. There is also a risk that a cyber event targets our Network Operations Control Centre.		We maintain a company-wide set of cyber security controls including protection, monitoring, physical security, continuous improvement and internal communications and training. We have an active cyber assurance programme, including security testing. We maintain controls between the corporate environment and the Control Centre and distribution assets. Our event response includes cyber event protocols, network tripping response and manual network workarounds. Section 8 – People and technology describes our cyber security approach in more detail, including our technology resilience investments.
Economic conditions and cost escalation	There is a risk that global economic events drive industry cost inflation higher or prolong elevated cost levels, increasing our operating costs and capital investment requirements beyond planned levels.		We manage this risk through interest rate hedging, improving our ability to estimate cost increases, and detailed discussions with our SDPs over future work programmes.
Workforce capacity and capability	There is a risk that there is a shortfall in the specialist workforce required by Orion and our SDPs. This risk is exacerbated by the step-change in workload throughout our CPP period as we address deferred renewals and deliver growth-related investment. Transmission and distribution specialist resources are under pressure nationally, and the competitive pull of the Australian market creates additional workforce retention challenges. There is also a risk that current skills present at Orion may not meet future required capabilities. Skills will need to match evolving customer and		We address these risks through workforce planning activities and assurance that identifies capability gaps and development needs. Section 8 details our workforce approach. Section 17 describes our delivery model and partnerships that enable us to scale capability to meet our AMP and CPP period workload demands. Further details on our engagement with SDPs, to ensure they can support delivery of the work levels in our CPP Application are provided in the CPP Main Proposal itself, Chapter 4 – Delivering our CPP plan.

Table 7.3 Orion's key risk areas and treatment approach

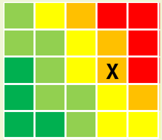
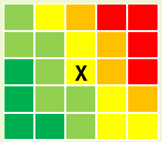
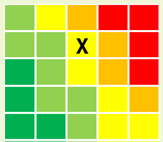
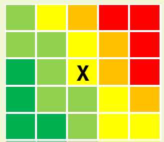
Risk area	Risk description	Risk profile (residual risk)	How we treat the risk area
	network demands in a more complex environment.		
Business capacity to adapt to change	There is a risk that our capacity to adapt to required changes amid industry transformation proves insufficient. As outlined in Section 3, the energy transition requires our network to evolve from one-way electricity delivery to managing two-way energy flows. There is also a risk that our low change management maturity and experience, combined with the large and complex nature of the programmes we are undertaking, will limit our ability to successfully deliver these changes.		We manage these risks through implementation of an integrated asset management (IAM) programme, embedding change management capabilities and shifting our ways of working. We are instigating wide-ranging changes to enhance and adapt our operations to serve customers in a transformed energy future. Section 9 outlines our transformation programmes and supports our strategic focus on enabling a highly utilised and accessible network. Section 8 describes how we are building organisational capability to support these changes, together with further details on our IAM programme.
Technology deficit and technical debt	There is a general risk that known areas of technology deficit at Orion require significant investment and bring various risks: **(1)** solution fit risk - selecting the best fit technology to see Orion into the future **(2)** data risk - data quality, location and errors **(3)** business process risk - building processes including ensuring data flow between systems **(4)** delivery risk - delivering a significant amount of change.		We address these risks through digital technology steering committees and leadership for the purpose of Orion-wide approaches to IT architecture, data, security and privacy, and AI and insights. We ensure appropriate budgeting and planning for technology lifecycle management including regular and scheduled upgrades. Section 8 details our digital technology operating model and the specific technology investments planned to address these deficits.
Network demand uncertainty	There is a risk that uncertainty regarding future network demand patterns will lead to mistiming of network investment. This uncertainty is exacerbated as technology for the energy transition is available now, however the timing of the transition is uncertain as it relies		We address this risk by utilising our Future Energy Scenarios to improve our ability to understand what may happen under different scenarios. We support the development of flexibility markets through trials, such as Resi-flex and evolving existing demand management, e.g. working with

Table 7.3 Orion’s key risk areas and treatment approach

Risk area	Risk description	Risk profile (residual risk)	How we treat the risk area
	on economic market factors. In the medium term, changes in technology and market solutions significantly increase the complexity of network investment decision making.		electricity retailers to combine our management of customer hot water load via ripple with their meter-based load control programmes. Our Market and Customer Innovation team also support the development of new forms of demand management to address one-off events where an emergency demand response is required. Section 10 outlines our approach to managing demand uncertainty, including our use of Future Energy Scenarios to test investment plans. Section 9 describes how we support the development of flexibility and demand-side management capabilities.
Energy transition constraints	There is a risk that various factors block or slow the energy transition, and that Orion's actions contribute or are perceived to contribute to this constraint. Potential constraints include current network design limitations, regulatory settings that limit our ability to adapt, shareholder prioritisation of funds, and our capability and capacity in network planning, delivery, and operation not matching demand.		We address this risk through partnership with industry to develop standard protocols and controls on connection of new technology to distribution networks. We undertake advanced forecasting and risk and sensitivity testing of the impact of new technologies. We actively seek relationships with demand-side aggregators and flexibility providers to promote the development of demand-side management and flexibility markets. Section 9 details our approach to enabling and responding to the transition. Section 10 describes how we incorporate non-network solutions and demand-side alternatives in our investment planning.

7.4 Building our resilience

Building resilience into our network is a priority. Our approach to resilience encompasses ensuring our capacity to continue to maintain vital services to the people and businesses of Central Waitaha Canterbury, while still engaging with the community.

We define resilience as our capacity to endure, adapt to, and rebound from substantial events, particularly High Impact Low Probability (HILP) events. As a lifeline utility operating in a region with high seismic risk and increasing climate-related hazards, we apply the National Emergency Management "4Rs" approach to HILP events: Reduction, Readiness, Response, and Recovery.

Our delivery of the 4Rs considers both Orion's needs, and the needs of our community, through our ongoing engagement with local and national lifeline utility groups.

7.4.1 Identifying HILP vulnerabilities

Identifying areas of our network vulnerable to HILP events underpins our resilience planning and investment decisions. We follow the assessment approach outlined in the EEA Resilience Guide and Orion's own Risk Management Guidelines, which involves:

1. **Identify vulnerabilities**: determining which assets are exposed to plausible HILP events
2. **Assess consequences**: estimating potential damage and supply interruption impacts
3. **Evaluate mitigation options**: identifying measures to reduce risk or speed recovery
4. **Undertake economic analysis**: comparing costs and benefits to prioritise resilience investment.

Our assessment considers the following HILP event categories relevant to Central Waitaha Canterbury:

- **Natural hazard risks**: severe earthquakes (including Alpine Fault rupture and secondary impacts such as tsunami and liquefaction), wildfires, landslips, and severe weather events (windstorms, floods and snowstorms).
- **Man-made and systemic risks**: major asset or cascading failures, cyber-attacks and technology failures, and security events.
- **Human resource and social disruption risks**: pandemics, toxic substance exposure, and other workforce disruptions.

Table 7.4 summarises the specific network vulnerabilities we have identified for HILP event, and the mitigation controls we have in place or are planning to implement to mitigate these risks.

Table 7.4 HILP events, network vulnerabilities, and mitigation controls

HILP event	Key vulnerabilities	Key mitigation controls
Severe earthquakes (Alpine Fault or other seismic events, including secondary impacts such as tsunami and liquefaction)	• Obsolete oil-filled 66 kV subtransmission cables connecting critical zone substations • Zone substation buildings and equipment not designed to current seismic standards • Single-circuit subtransmission routes serving critical loads without alternative supply	• 66 kV cable and conductor replacement programme • Zone substation seismic strengthening, including structural upgrades for buildings below 67% NBS • IL4-rated Network Operations Control Centre • Critical spares • Mutual aid agreements with other EDBs
Fire and severe weather events (floods, wind, landslips, snowstorms)	• Overhead lines in high-wind exposure zones • Network assets in flood plains • Critical sites with limited emergency access • Vegetation interference with network assets	• Use of fire resistant composite poles in high fire risk areas • New zone substations, or major works at zone substations, civil works are designed to the latest standard for flooding • Vegetation management programme

Table 7.4 HILP events, network vulnerabilities, and mitigation controls

HILP event	Key vulnerabilities	Key mitigation controls
		• New distribution box design to replace existing boxes if inundated • Mobile generation capability • Mutual aid agreements with other EDBs
Major asset or cascading failures	• Zone substations serving high customer numbers • Major 66kV/33kV supply points with limited redundancy • Grid exit points with single-supply dependencies	• Contingency plans for critical sites • Critical spares • ADMS with automated restoration (APRS, PORT) • Contingency operations centre at Papanui Zone Substation • Zone substation fire risk remediations
Cyber-attacks and technology failures	• Network Operations Control Centre as single point of control • SCADA and operational technology systems • Communications systems for remote monitoring	• Cyber security controls and monitoring • Active cyber assurance programme with security testing • Contingency Operations Centre backup capability
Pandemics or workforce disruptions	• Operations requiring physical presence (control centre, field crews) • Service delivery partner capacity constraints	• Remote working capabilities for staff • Staff segregation protocols and alternate sites • Business continuity plans for all business units

7.4.2 Reduction

Within our risk management practices, outlined earlier in this section, we identify and analyse long-term risks to our network and information technology assets from HILP events. We then identify mitigations to reduce the magnitude of the impact of these risks on our network. Our mitigations can be classified into three types as follows.

7.4.2.1 Hardening

Section 14 outlines our approach and examples of mitigations to reduce the impacts on our network from events such as floods, fires, wind, and earthquakes.

Risks are assessed and mitigations proposed based on site exposure to HILP events, the current mitigations in place, and the age and condition of existing assets. Where assessed to merit investment, mitigations are put in place to enable these sites to better withstand HILP events. Our risk assessment and proposed mitigations account for current levels of risk and projected increasing levels of risk through climate-related change, where relevant.

7.4.2.2 Diversity

Our 66 kV cable and conductor replacement programme (outlined in *Appendix E – Major asset renewal projects*) will improve our network diversity and resilience by replacing legacy oil-filled cables with modern cables, and creating alternative supply paths where feasible. We also consider distributed energy resources, such as batteries and mobile generation, to maintain supply during major events.

7.4.2.3 Technology resilience

Section 8 outlines our approach to reduce the risk on our information technology and operation technology (including SCADA) of cyber-attack and risk mitigation from the impact of major events through data centre resiliency.

7.4.3 Readiness

There are several elements to readiness at Orion that enable us to deliver all elements of the National Emergency Management approach for HILP events. Our approach can be classified into three areas as follows.

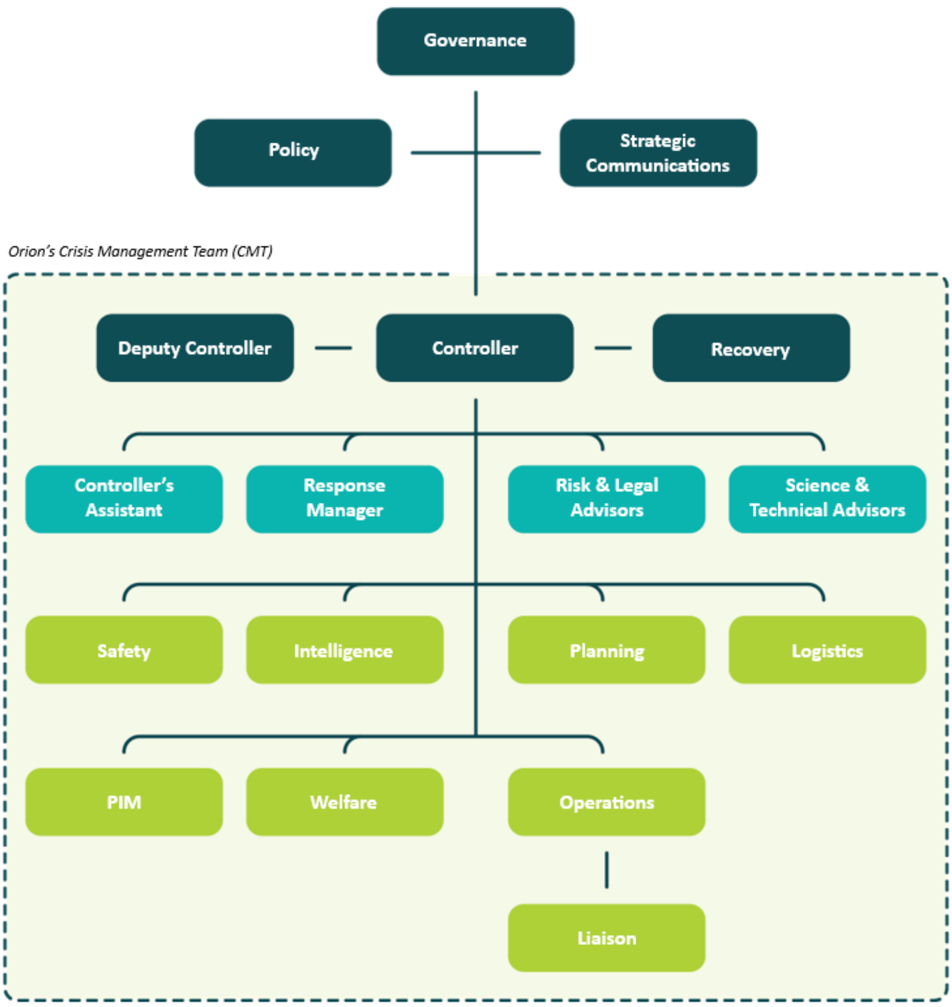
7.4.3.1 Preparedness

We have adopted the Coordinated Incident Management System (CIMS) model for managing emergency and crisis-level events across all event types. This system aligns with New Zealand's official emergency management framework, ensuring our response is consistent with other utilities and emergency services which will enable more effective and coordinated incident management.

Capability at the Incident Management Team (IMT) level is now well established. We have completed CIMS training for 60 team members across Orion, including our Integrated Leadership Team. All emergency management documentation has been reviewed and updated so that the CIMS model is embedded at the core of our emergency and crisis management processes. We continue to conduct simulated emergency practice exercises to ensure that capability is maintained. An ADMS simulator, planned for commissioning in FY27, will enhance our training capabilities by enabling realistic scenario-based exercises.

All key components of effective emergency and crisis response are in place. Our emergency response structures and roles (as outlined in Figure 7.4), and terminology are fully aligned with the CIMS model. Where appropriate, tools and information from our previous crisis management system have been retained to complement the new framework.

Figure 7.4 Orion's Incident Management Team structure



In addition, we have business continuity plans in place across Orion for business units to enable continued operation in the event of an emergency. We have put in place significant back-up provisions for our key operational functions.

Supporting these business continuity capabilities, we maintain a comprehensive suite of contingency plans that provide detailed procedures for specific emergency scenarios. Table 7.5 summarises our key contingency and business continuity plans.

Table 7.5 Examples of Orion's contingency and business continuity plans

Plan type	Examples	Review frequency	Storage location
Substation contingency plans	Substation restoration procedures for load transfer and supply restoration (per substation)	Every 2 years, or when significant network changes occur	ADMS
Event-specific contingency plans	Natural Event/Equipment Failure (NW20.40.01) Emergency Generator Supply (NW20.40.02) Loss of Supply (NW20.40.03) Demand Disconnection (NW20.40.05) Irrigation Load Shedding (NW20.40.07) Security of Supply Rolling Outage Plans (NW20.40.09)	Annually (some on 2-year cycle based on risk)	SharePoint
Business continuity plans	Critical business function continuity, backup provisions for operational functions	Every 2 years, or when significant changes to business processes or functions occur	SharePoint

7.4.3.2 Resources

We maintain a range of resources to support readiness for our emergency response:

- **Procedures**: this includes resources for the Incident Management Team to use in an emergency.
- **Sites**: our administration building, which houses our Network Operations Control Centre, was built to Importance Level 4 (IL4),[24] and designed to remain operational following a 1 in 500-year seismic event. That building is also equipped with a standby generator and diesel tank for back-up power. We also have a Contingency Operations Centre at our Papanui zone substation.
- **Spares**: emergency supplies of vital, core equipment, such as power transformers, key switchgear components, subtransmission cables and accessories, and communications/SCADA equipment, and 3.5 MVA of transportable diesel generation are stored at our Connetics depot and our Papanui Contingency Operations Centre.
- **Service delivery partners**: we smooth our planned network opex and capex over time so our SDPs can develop and maintain locally sourced capability that may be redeployed to respond when HILP events occur.
- **Remote working**: we have set up our workforce with equipment to enable them to work from home.

[24] IL4 refers to Importance Level 4 which applies to essential buildings, including lifeline infrastructure. The importance levels are set out in the Building Code.

7.4.3.3 Community, stakeholders, and partners

We participate in readiness activities and foster an empowered and prepared community which can navigate disruptions. This is seen through:

- **Lifeline preparedness**: we engage with the Canterbury Engineering Lifelines Group to ensure we are able to respond in a coordinated way in the event of an emergency.
- **Contract suppliers**: our service delivery partners have emergency works requirements included in their contracts.
- **Industry**: we have formal and informal mutual aid agreements with EDBs around New Zealand to provide additional support in HILP events, if needed. We also participate in Transpower's Industry Exercise to practice how we take part in managing HILP event impacts on Aotearoa New Zealand's power system, and minimise any impact on consumers.
- **Education and engagement**: we proactively engage with the community to raise awareness about electricity safety, energy efficiency, and preparedness during power outages. We run a comprehensive advertising programme covering tree trimming, DIY safety, and farm safety around power lines. We have also added our 'Dial it in' campaign in response to ongoing tampering with our network. The Snap Send Solve app also provides an accessible way for our community to report something out of place on our network.
- **Collaboration**: we partner with local government, businesses, and non-profits which allows us to integrate our services seamlessly, ensuring that the community receives timely support during emergencies.
- **Adaptability**: our initiatives, such as supporting community-based renewable energy projects or energy education, empower individuals to be energy resilient and self-sufficient. We have information on our website about being prepared for a power outage and how to cope.
- **Event communications**: customer communication is fully built into the Incident Management Team and procedures. In a HILP event our Customer Support team will provide regular, updated messaging during outages, to keep people informed.

7.4.4 Response

Over the past 15 years we have developed and matured our response capability. After significant events, such as the 2010 and 2011 Canterbury earthquakes, the 2017 Port Hills Fire, and the 2020 COVID-19 pandemic, we recognised the need for a more structured and coordinated internal response protocol. The outcome of this assessment was the introduction of our CIMS framework in 2022.

Since then, we have activated CIMS responses for events ranging from public safety through to major weather events, such as the recent Canterbury windstorm in October 2025, a hazardous substance evacuation at our head office in March 2026, and more recently standing up a CIMS response to the fuel crisis fuelled by recent global events. In addition, a planned CIMS 'cyber-attack' simulation exercise was successfully held, using a 'walk, crawl, run' methodology for planning. The execution of this exercise helped to maintain the skills of our workforce, strengthen their capability, and test that our processes and systems will operate as intended should the need arise.

As a result of various post event debriefs, assessments and analysis, we have identified various learning opportunities. These lessons have ensured that we continuously improve our response capability.

These improvements include:

- introducing a specialist support process for persons exposed to potentially traumatic events
- upgrading communication and monitoring of lone and remote workers (digital radio with live GPS enabled tracking and access to personal locator beacons)

- developing Incident Action Plans for key HILP events ranging from severe weather events, reputational damage, and network cyber attack
- using our Situational Awareness Dashboard to create geospatial real time identification of specific areas of concern and developing conditions (weather, road closures, slips etc). This information aids our decision making and could result in our not responding where conditions are unsafe for workers in the field.

Since implementing our CIMS framework, our confidence in our capability to stand up a CIMS response to a HILP event has increased.

7.4.5 Recovery

Following a HILP event, we reassess risks and reprioritise our plan including major works to restore our network condition and capability over an appropriate period. The recovery phase may involve prudent upgrades to parts of our network, taking account of any new learnings about risk and new context from the HILP event.

8

8. People and technology

Our people and technology are enablers for achieving our asset management objectives. This section describes how we are building our workforce capability and deploying digital systems to meet the evolving needs of our network and community. We outline our core teams and their functions together with the strategic technology investments that will transform how we manage our assets and serve customers.

We are positioning ourselves to efficiently deliver an expanded work programme over the AMP period, while adapting to the rapidly changing energy landscape. This requires us to both grow our workforce capability and continue to modernise our technology platforms to support more sophisticated asset management, enhanced customer service, and the integration of distributed energy resources (DER).

Our Innovation strategy update, in Section 9.5 – Innovation practices, outlines the innovation projects we have already undertaken, or are planning to begin in this AMP period. We seek to use these new asset data and management technologies and processes to deliver efficiencies in our network management and operations and maintain our quality of service.

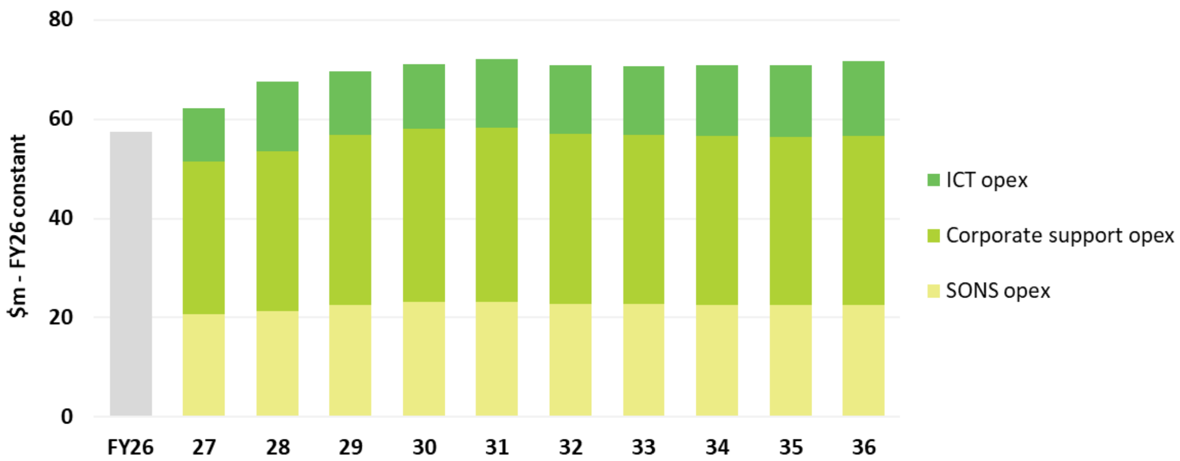
Our approach to delivering our work programme, including our partnerships with our service delivery partners, procurement strategies, and management of delivery risks, is covered in Section 17 – How we deliver.

8.1 Investment overview

Our people and technology investment totals $800 million over the FY27–FY36 period, comprising $697.1 million in operating expenditure (opex) and $74 million in capital expenditure (capex). This investment ensures we have the workforce capacity, capability, and digital systems needed to deliver our proposed investment programme and operate an increasingly complex network. For expenditure related to network transformation and flexibility programme activities, see Section 9 – Transforming our network. For expenditure related to both routine and non-routine corporate capex for non-network assets, see Section 15.

Figures 8.1 and 8.2 show the total proposed opex and capex per annum respectively.

Figure 8.1 Orion's people and technology opex per annum

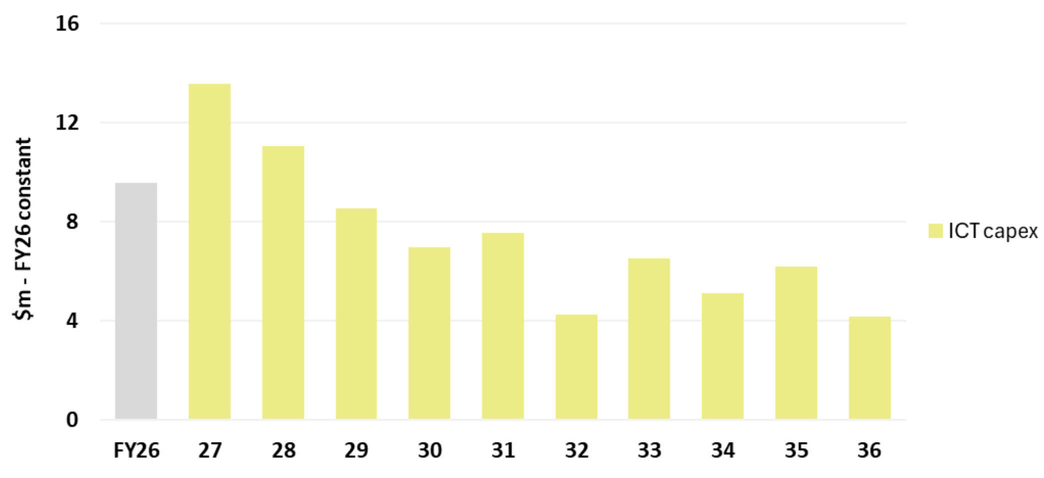


Opex increases through to the early 2030s, reflecting the additional staffing required to support growing work volumes, an increasingly complex network, and higher Information and Communication Technology (ICT) running costs as new systems are deployed. From FY32 onwards, expenditure moderates in line with slightly reduced work volumes and the increasing impact of anticipated efficiencies from capability uplift and system improvements.

People and technology opex comprises:

- **System operations and network support (SONS) opex**: these functions represent approximately 60% of our workforce with salaries comprising the bulk of the SONS cost (approximately 75%). This includes the teams directly involved in managing and operating our network, including engineering, network operations, connections, network portfolio, asset management, and health and safety. Other costs in SONS include asset storage costs and vehicle costs. Increased expenditure reflects the need to grow our headcount and develop specialised roles to manage a more complex, digitalised network, including LV controllers, release planners, and network planning engineers.
- **Business support opex**: these functions represent approximately 40% of our workforce with salaries also comprising the bulk of the Business Support cost (approximately 60%). This includes the teams associated with corporate functions, including finance, revenue and regulation, people and capability, customer engagement, digital and data, and governance. Other costs in Business support include insurance, consultancy and general business overhead such as travel, training and electricity. Increased expenditure supports the sophisticated financial analysis, regulatory expertise, data management, and strategic planning needed to deliver our proposed investment programme.
- **ICT opex:**[25] ongoing operational costs associated with running our digital and technology environment, including software licensing, system support and maintenance, and data hosting. Increased expenditure reflects an increased shift to SaaS (Software as a Service) solutions, continued investment in our ICT capability and changed accounting standards that result in a shift of expenditure previously recorded as capex to opex.

Figure 8.2 Orion's people and technology capex per annum



Capex is concentrated in the earlier years of the AMP period, which is driven by our ICT modernisation programme (see Section 8.6). Capex moderates over the latter half of the AMP period as major programmes are completed and we transition to ongoing operational costs.

The people and technology capex comprises:

- **ICT capex[26]:** investment in ICT change initiatives that enhance our asset management and operational capability. This includes the Integrated Asset Management (IAM) programme, our most significant technology investment, along with Advanced Distribution Management System

[25] In Schedule 11B, ICT opex is included within the Business Support expenditure category.
[26] In Schedule 11A, ICT capex is included within the non-network assets expenditure category.

(ADMS) upgrades, cybersecurity enhancements, data platform development, and core infrastructure modernisation. From FY29 onwards, capex falls back slightly and a pattern where there are peaks every two years, associated with asset refresh and re-licensing cycles, starts to emerge.

This investment is linked to two main investment priorities: improving capability to drive efficiencies and supporting network activities.

Improving our ICT systems and tools enables us to keep our network running smoothly, respond faster to outages, plan, and better understand how our customers use electricity. Smarter decisions, enabled by better systems and data, supports renewals targeting, growth planning, resilience investments, and technology integration.

8.2 System operations and network support teams

SONS encompasses the teams directly involved in managing and operating our electricity network. The SONS teams are focused on:

- improving efficiency by adopting better systems and technology
- upholding network reliability, safety, quality standards, and resilience
- responding efficiently to events and failures to maintain reliability
- managing new connections and the resulting increase in network activity effectively and efficiently.

8.2.1 Core functions

Our SONS teams deliver core functions including:

- **Engineering Support**: establishes technical standards and specifications for network design and equipment selection. This team ensures our network operates safely and efficiently through robust engineering practices and systems that control and protect network assets.
- **Network operations**: provides 24/7 monitoring and control of our network, responding to faults and maintaining system security. This includes our control centre operations, field response capabilities, and coordination of network access for maintenance and construction activities.
- **Customer connections**: plans and facilitates the connection of new customers to our network, from simple residential connections through to complex commercial and industrial installations requiring network reinforcement.
- **Network portfolio**: develops detailed work packages and specifications for contractor execution, ensuring all works meet our technical standards and are delivered efficiently.
- **Asset management**: focuses on long-term network needs through strategic planning, condition assessment, and development of maintenance and replacement programmes. This team produces our AMPs and ensures investment decisions are optimised across the asset lifecycle.
- **Health and safety**: ensures all staff and service delivery partners operate in accordance with best practice safety requirements, maintaining our strong safety culture across all network operations.

8.2.2 Workforce development

Our objective for SONS is to maintain a sustainable, prudent, and efficient level of resourcing, while also ensuring that the skills and capabilities of our staff evolve in response to changes in our operating environment.

We will need to increase our headcount through to the early 2030s, to ensure we can effectively manage and support growing work volumes, and an increasingly complex network. From FY32 onwards, our headcount is expected to decline in line with slightly reduced work volumes and the increasing impact of anticipated efficiencies.

Alongside headcount growth, we are focused on improving the capability of our teams. More capable people deliver higher throughput, manage complexity better, and achieve better outcomes with fewer resources. Our capability uplift strategy is therefore integral to delivering an efficient work programme over the AMP period.

To support our network transformation and the management of an increasingly digitalised network, we are identifying and building capability in several areas that are not fully represented in our current workforce. These include real-time management of the LV network, LV network planning and release coordination, long-term network development and load forecasting, protection and control engineering, and operational technology management.

The specific roles, numbers, and timing through which we develop this capability will be determined progressively as our programmes mature, informed by our workforce planning process and the pace of network transformation.

8.3 Business support teams

Business support encompasses the corporate functions that enable our network operations. These teams provide essential services including finance, commercial, regulatory management, people and capability development, customer engagement, and governance.

8.3.1 Core functions

Our Business Support teams deliver the following core functions:

- **Leadership and Governance**: our Integrated Leadership team drives strategic direction and ensures effective governance across Orion. This function includes board support, risk management, and maintaining our insurance programme to protect against material risks. Our governance framework ensures that decision-making is robust, transparent, and aligned with both shareholder expectations and regulatory requirements.
- **Finance, Revenue and Regulation**: our Finance team manages financial planning, reporting, and treasury functions while ensuring regulatory compliance. This function includes monthly reporting, year-end reporting, accounts payable and receivable, regulatory disclosures, and treasury management. Our Revenue and Regulation team oversees pricing strategies, manages our relationship with industry regulators, and handles major customer contracts. This function ensures financial sustainability while delivering value for customers.
- **People and Capability**: our People and Capability team provides strategic HR support to build organisational capability, administering recruitment, development, performance management, and payroll while driving our transformation to a skills-based organisation. The team is establishing a Learning Centre of Excellence to accelerate capability uplift and embed culture change across Orion.
- **Customer and stakeholder engagement**: our Customer and Communications teams are responsible for external and internal engagement, ensuring we understand and respond to stakeholder needs. They manage our customer support centre, which operates 24/7 and handles over 1,800 customer calls monthly, providing real-time outage information and resolving service queries. These teams also lead our stakeholder consultation programmes, community engagement initiatives, and communications strategies that build understanding and support for our network investment plans.
- **Digital, Data, and Technology**: our Digital, Data, and Technology team provides strategic oversight of our digital transformation, leading the deployment of advanced analytics, artificial intelligence, and data governance frameworks that enable data-driven decision making. This team is

instrumental in ensuring our technology investments deliver measurable benefits and that AI tools are deployed securely and effectively.

8.3.2 Workforce development

We aim to maintain appropriate staffing levels in Business Support to balance efficiency with capability, ensuring our teams develop the skills needed to support our evolving business requirements.

As with the SONS teams, we anticipate that through to the early 2030s, we will require an increase in headcount in the Business Support teams to support the growing scale of the business. From FY32 onwards, headcount is expected to decline in line with slightly reduced work volumes and the increasing impact of anticipated efficiencies.

We are also focused on improving the capability of our teams. Our capability uplift strategy recognises that Business Support functions must evolve in parallel with SONS to effectively enable network operations. Increasing our staff numbers and improving capability will ensure that our Business Support teams can provide the sophisticated financial analysis, regulatory expertise, data management, and strategic planning needed to support Orion’s future needs.

8.4 Information and communication technology

Effective management of our network depends increasingly on the quality, integration, and security of our digital systems and the asset information they hold.

Our ICT portfolio encompasses both corporate information technology and operational technology (OT) - the full range of digital, data, and communications systems across Orion's organisation. It covers computing and IP network infrastructure, operating environments, applications, data and integration platforms, and associated services across all hosting arrangements. Together, these systems provide the foundations that underpin our core business processes and the safe and reliable operation of the network.

Orion deferred major ICT system upgrades in the years following the Canterbury earthquakes. During this period, our ICT strategy prioritised minimising business disruption while we focused on recovery from the earthquakes and supporting remote work and workforce mobility during the COVID-19 pandemic.

While prudent at the time, this approach meant that many of our core ICT systems became outdated. By FY23, several key platforms were approaching, or beyond, the end of their useful life. We commissioned independent reviews by specialist consultants of the key elements of our systems – including integrated asset management, operational technology, and cybersecurity. These reviews confirmed that, without significant renewal or replacement, our core systems would not be fit for future business needs and posed an increasing risk to business operations due to their vulnerability to cyber threats. In addition, Orion lacked many of the digital capabilities increasingly required for good practice network management and meeting evolving customer expectations.

By FY24 and FY25, further deferral was no longer prudent. Orion began a catch-up and capability-building phase that we are still in the midst of.

The changing energy landscape demands new capabilities to support a more distributed and decentralised electricity system. Without effective ICT, the analytical tools, forecasting models, and innovative solutions that are increasingly central to managing a modern electricity distribution network cannot function. Equally, without sustained investment, Orion would be unable to deploy the digital capabilities needed to manage growing network complexity and deliver good outcomes for customers. ICT investment has a significant risk management benefit that gives customers greater confidence that Orion can deliver on its commitments and plan renewals and investments with accuracy and foresight.

This section brings together the strategic context and physical infrastructure of our ICT environment, our approach to managing asset information systems, and the programmes we are undertaking to modernise both. It describes how we manage our ICT assets through their lifecycle, and how the integrity of the data held within those systems underpins sound operational and investment decisions across Orion.

8.4.1 Strategic ICT investment

We have several strategic ICT drivers that support our transition from managing a passive network with one-way power flows to actively orchestrating energy distribution where customers are both consumers and producers:

- **Increasing digital engagement**: service delivery partners and customers increasingly expect efficient digital tools. We are expanding platforms to provide work order management and asset data access for service delivery partners, and web portals for customers to access outage information and connection services, addressing expectations for accessible, timely information.
- **Becoming data-driven**: the rise of DER and changing customer expectations mean we must process and analyse significantly more data. We are investing in data collection, integration, and advanced analytics, including AI. This will enable data-driven decision-making that improves operational efficiency and network reliability, and ensures we are optimising our asset management approach: neither under-servicing assets and accepting avoidable risk, nor over-servicing them at unnecessary cost to customers.
- **Supporting business change**: renewing core system platforms that are reaching end-of-life will ensure reliability and enable new capabilities that support our future operational requirements.
- **Meeting regulatory and compliance obligations**: evolving regulatory requirements around reporting and data provision drive our investments to produce accurate regulatory reports efficiently and facilitate data exchange with regulators and market operators.
- **Improving operational efficiency**: pursuing efficiency through system integration will eliminate manual data re-entry and allow automation of routine tasks. These investments will save time, reduce errors, and contribute to cost-effectiveness.
- **Strengthening cybersecurity and risk management**: as our ICT environment grows, robust cybersecurity is non-negotiable. We are strengthening cyber defences and monitoring capabilities to protect operational systems and sensitive data, and safeguard network reliability and customer data.

These drivers, alongside the priorities identified through customer engagement, shape our investment programme. Our ICT investment directly supports the following customer priorities:

- **Safety, reliability, and resilience**: by replacing aging systems, implementing robust cybersecurity, and enabling faster fault response through better data and tools.
- **Affordability**: through operational efficiencies, automation, and optimised use of existing assets.
- **Future fit – new technologies**: by enabling integration of DER and supporting decarbonisation.
- **Customer experience**: through faster service delivery, better information access, reduced disruptions, improved digital channels, better outage information, and transparent data sharing.
- **Growth**: by providing scalable digital platforms and integrated asset information, our ICT investments support the efficient planning and connection of new customers, DER, and network capacity required to meet increasing demand.

Table 8.1 summarises our material ICT capex, maintenance, and renewal projects and programmes over the next five years (FY27-FY31).

Table 8.1 Material ICT projects and programmes over FY27-FY31 ($m, FY26 constant)

Project or programme	Project or programme details	Capex	Opex
Integrated asset management (IAM)	Investment to transform our legacy asset management platform into a modern system that incorporates predictive maintenance, integrated safety management, automated inspection capabilities, and investment planning tools. This will enable faster power restoration times and improve investment decision-making and planning for renewable energy integration.	5.0	6.0
Data centre infrastructure	Maintenance and capacity growth investment in our two transportable data centres. This infrastructure is used for all core systems, and each has the capacity to run essential systems for operations during an adverse event.	4.7	4.0
Cybersecurity	Investment to manage cybersecurity risk. Unauthorised access to our network infrastructure could enable malicious actors to manipulate our electricity distribution systems, potentially leading to considerable disruption to our communities and businesses.	3.2	4.7
Customer engagement platform	Ongoing investment to improve and enhance our customer engagement platform and integrated customer portal to allow us to continue delivering critical customer-facing services cost effectively while meeting the growing needs of customers through tailored services.	2.6	3.9
Advanced digital management system (ADMS)	Our ADMS platform is the critical operational technology system that directly controls and monitors our distribution network. The investment ensures network reliability through automated fault management, reducing customer outage frequency and duration while preparing for future grid modernisation requirements.	2.8	3.3
User devices	Investment to supply and support end-user devices for Orion's employees, including phones, desktop, or laptop computers, and mobile tablets for field workers. Most devices are replaced on a 3–5 year cycle to ensure capability and operability are maintained.	4.6	1.5
Geospatial intelligence system	Investment in additional value-creation initiatives in geospatial technologies to maximise the value of our current Esri ArcGIS platform investments and related technology services. This aligns with regulatory requirements and delivers measurable benefits to network reliability, asset management efficiency, and customer service delivery.	8.3	2.5
Billing and registry management	Ongoing licensing, support, maintenance, and enhancement of our AXOS platform to efficiently provide regulatory-compliant billing and registry management services, and cost effectively implement more segmented pricing structures, reducing the potential for inefficient cross-subsidisation among consumers.	0.1	4.8
Data analytics platform	We need to securely store, process and deliver insights from the increasing volume of data (currently more than 30 billion records) we hold. This investment enables us to meet regulatory reporting requirements efficiently due to searchable and accessible data, optimise network performance, gain insights into customer service improvement opportunities and meet industry standards in data-driven asset management.	3.1	3.6
Microsoft licensing	Microsoft operating systems and productivity software are foundational to Orion's ability to operate. Our software licensing agreement encompasses numerous core productivity platforms, applications, and services used by Orion's employees.	-	3.6
Artificial intelligence (AI)	Strategic AI investment is essential for managing the risks associated with AI adoption while capturing its transformative benefits. This investment in controlled AI capabilities will protect Orion from the security, compliance, and other associated risks of unmanaged AI adoption while positioning Orion to lead in AI-driven operational excellence and customer engagement.	2.2	4.9
Integration platform	Expenditure to improve operations and customer service through better system integration. Our current environment still includes a mix of modern service-oriented	0.5	2.7

Table 8.1 Material ICT projects and programmes over FY27-FY31 ($m, FY26 constant)			
Project or programme	**Project or programme details**	**Capex**	**Opex**
	integrations and legacy point-to-point connections that are increasingly difficult to maintain and pose security risks.		
Telephony system	Expenditure to replace the communications backbone for our operations and customer service contact centre. The existing system is inefficient and has an increasing risk profile given it is no longer supported in New Zealand. This is a critical infrastructure component for our operations.	1.4	2.6
Finance system	Expenditure in our fit-for-purpose, software-as-a-service finance system to ensure we can accurately and efficiently report on our actual performance and continue to comply with good governance and management practices as well as financial, tax, Electricity Authority, and Commerce Commission reporting requirements.	-	2.5
People and culture	Ongoing expenditure in the support, maintenance, and enhancement of technology systems underpinning Orion's People and Capability team. This expenditure is critical to achieving our strategic objective of 'Creating the preferred workplace' and managing anticipated workforce challenges in the electricity distribution sector.	-	1.9
Knowledge management	The volume of information, documents, and knowledge across our digital systems continues to grow. Investment in an enterprise-wide approach to knowledge management will enable our people to efficiently access the up-to-date information they require to make business, operational and network decisions.	-	2.1
Total major projects/programmes		**38.4**	**54.7**

The following sections describe our approach to ICT infrastructure, asset information management, and business systems in detail.

8.5 ICT infrastructure

Our ICT infrastructure provides the computing, storage, networking, and cloud services that enable our business operations and network management. This infrastructure must be reliable, secure, and scalable.

This infrastructure operates 24/7 to support critical network operations, with our control centre systems requiring greater than 99.9% availability to ensure continuous monitoring and control of our network.

With independent third-party reviews confirming the need we are upgrading or replacing core infrastructure including servers, storage systems, and networking equipment, that have reached or are approaching end-of-life. This renewal supports growing data volumes and processing requirements.

This work also includes implementing technologies that improve resource utilisation and enable faster deployment of new applications.

Details of our ICT infrastructure is set out in the following sections.

8.5.1 On-premises data centres

We maintain primary and secondary data centres that host our critical network control systems. These systems require stringent reliability and latency requirements and must continue operating during civil emergencies or wide-area network outages. By keeping modular and containerised on-premises data centres with direct connections to our private telecommunications network, we maintain the control and isolation necessary for operational resilience.

Our data centre facilities feature redundant power supplies, cooling systems, and physical security measures appropriate for critical infrastructure. We regularly test disaster recovery to ensure we can maintain operations even in the event of a major site failure.

We have designed this infrastructure with resilience at multiple levels:

- geographic separation of primary and secondary data centres
- redundant network paths and diverse telecommunications carriers
- regular backup and recovery testing
- documented procedures for operating in degraded modes
- alternate control centre facilities that can be activated if primary facilities are unavailable.

This layered approach ensures we can maintain critical operations through a wide range of disruption scenarios, from individual equipment failures through to major events affecting entire sites.

8.5.2 Cloud services

We use cloud platforms for applications that benefit from scalability and modern capabilities. This approach helps us avoid heavy capital investment in local hardware while providing flexibility to scale resources as needed. The platforms include our customer engagement platform, billing system, data analytics, and various business systems offered as software-as-a- service (SaaS).

Our approach to adoption of cloud platforms is deliberately measured and risk-based, balancing the need to modernise legacy on-premises systems with the operational requirements of critical infrastructure.

We assess the optimal hosting model, considering factors including:

- criticality and latency requirements
- data sovereignty and regulatory considerations
- cost-effectiveness over the asset lifecycle
- integration requirements with other systems
- vendor lock-in risks and exit strategies.

This pragmatic approach ensures we gain cloud benefits, scalability, innovation, and reduced capital intensity, without compromising the resilience of critical operations. We continuously reassess this balance as cloud services mature and our operational requirements evolve.

8.5.3 Modern data platform

We have implemented a modern data platform, as part of our strategic shift from fragmented legacy data repositories, that consolidates data from across our systems, enabling advanced analytics and AI applications. This platform provides the foundation for data-driven decision-making across asset management, network operations, and business planning.

The platform ingests data from multiple sources, including SCADA telemetry, smart meter readings, asset management systems, financial systems, and external sources such as weather data, and makes that data available for analysis through a common data model.

This approach improves on our previous situation where analysts spent significant time locating, extracting, and cleaning data before any analysis could begin. The platform also provides capabilities for machine learning model development and deployment, supporting our AI initiatives.

Our integrated platform enables automated data flow between systems, which eliminates manual re-entry, and ensues consistency. This integration extends from operational systems through to business intelligence and reporting tools.

8.5.4 Cybersecurity infrastructure

As cyber threats evolve, we implement enhanced security infrastructure and services across on-premises and cloud environments. This includes next-generation firewalls, intrusion detection systems specific to industrial control protocols, and security monitoring capabilities that provide continuous visibility across our entire technology estate.

We maintain a security monitoring function that combines automated threat detection with expert analysis, enabling rapid response to potential incidents. This includes Security Information and Event Management systems that correlate events across our entire environment, identifying patterns that might indicate cyber-attacks.

We have also established a Zero Trust architecture for our OT systems, ensuring that every access request is authenticated and authorised regardless of where it originates.

8.5.5 Network and communications

We connect field devices to our control centres through a mix of fibre optics, radio links, and cellular networks. This multi-technology approach provides the redundancy essential for reliable network operations and for connecting remote locations.

We are continuing to strengthen our operational communications through smart switching equipment in substations that enables remote monitoring and configuration, encrypted communications for SCADA systems to protect against interception or tampering, and enhanced network management capabilities that improve visibility and troubleshooting.

8.5.6 End-user computing

We manage laptops, tablets, and mobile devices that enable our workforce to operate effectively both in office and field environments. Our device management strategy focuses on:

- standardised configurations that reduce support complexity
- mobile device management capabilities that enable secure remote work
- regular refresh cycles that maintain performance and security
- modern collaboration tools that improve productivity.

Field workers are equipped with rugged tablets (a sturdy type of tablet) that provide access to asset information, work orders, and safety procedures, while enabling real-time updates to our systems from job sites.

8.5.7 Asset management information and data

Our asset information systems form the digital backbone that supports operational decision-making, maintenance planning, investment prioritisation, and regulatory compliance. These systems need to work together seamlessly to provide a single source of truth about our network's configuration, condition, and performance.

The following sub-sections describe the processes used to identify asset management data requirements across the full asset lifecycle, the systems used to manage and monitor that data, the controls in place to ensure data quality and accuracy, and the extent to which these systems and processes are integrated.

8.5.7.1 Identifying asset management data requirements across the asset lifecycle

Our approach to identifying what asset management data we need is driven by the information requirements of each stage of the asset lifecycle, from planning and design, through construction and commissioning, into operations, maintenance, and ultimately decommissioning and disposal. At each stage, different business functions rely on specific data sets, and our data requirements are defined accordingly.

Data requirements are identified and reviewed through several complementary processes:

- **Asset lifecycle requirements mapping**: for each asset class, we define the data attributes required to support the full asset lifecycle, from creation through to decommissioning. These requirements are documented and maintained in our asset data standards and are used to configure data fields in our asset management information systems. The IAM programme, described in Section 8.6.2, is providing a key opportunity to refresh and formalise these requirements across all asset classes.
- **Regulatory and compliance-driven requirements**: evolving regulatory disclosure requirements drive specific data collection and reporting obligations. These are identified as part of our regulatory engagement and translate directly into system configuration and data capture requirements. Our data analytics platform and integrated reporting tools are designed to meet these obligations efficiently and accurately.
- **Operational and investment decision requirements**: the data needed to support asset health assessments, condition-based maintenance, load forecasting, and investment prioritisation is identified through our asset management planning processes. Data owners and stewards in our Asset Information team work with asset managers to ensure that the right data is being collected and is accessible in the right form for decision-making.
- **Data gap identification and improvement programmes**: our Asset Information team runs an ongoing programme of work to identify gaps in asset data, prioritise their remediation, and track improvements over time. This includes targeted data clean-up campaigns, enhanced data capture requirements for new field work, and systematic audits of key data sets. Gap identification informs both near-term remediation activity and longer-term system investment decisions.
- **Field capture at point of work**: data requirements are embedded into field processes and work order templates so that asset data is captured accurately at the time work is performed, rather than retrospectively. Mobile tools enable field workers to update asset records in real time, and work completion processes include checks that relevant data attributes have been populated to the required standard.

8.5.7.2 Systems used to manage asset data

The following, Table 8.2, sets out the primary systems we use to manage asset data, record asset conditions and operational capacity, and monitor the performance of our network assets.

Table 8.2 Primary asset management information systems

System	Role and data managed
Asset Management Information System	Our primary asset management information system holds detailed technical specifications, maintenance histories, condition assessments, and work order records for network assets across the full lifecycle. It is the core system for recording asset condition and operational capacity. The IAM programme is replacing and significantly enhancing this platform, establishing it as the single authoritative source of truth for asset data (see Section 8.6.2).
Geographic Information System	Our GIS is the authoritative source for network topology, asset locations, connectivity, and geospatial data. It provides the spatial foundation underpinning both planning and operational activities.

Table 8.2 Primary asset management information systems

System	Role and data managed
	Data from the GIS feeds into network planning, design, and investment prioritisation processes. Our geospatial intelligence programme is expanding the analytical value derived from this platform.
Advanced Distribution Management System (ADMS)	Our ADMS provides real-time monitoring and control of the distribution network, integrating outage management, power flow analysis, and automated fault management. It records and provides critical operational data on network loading, capacity, and performance, and is the primary system for monitoring network asset performance in real time. Ongoing investment in the ADMS is enhancing its capabilities through the AMP period.
Data analytics platform	Our modern data platform consolidates data from across our systems – including SCADA telemetry, smart meter readings, the asset management system, financial systems, and external data sources – into a common data model. It provides the foundation for advanced analytics, regulatory reporting, asset performance monitoring, load forecasting, and AI-driven insights. Currently holding more than 30 billion records, it is a critical source of information for asset management decision-making
Billing and Electricity Registry system	Our billing and Electricity Registry management platform holds records for all connected ICPs (installation control points) together with their regulatory and market attributes. It manages energy consumption data, revenue assurance functions, and interfaces with Electricity Authority registry requirements. This system is critical for regulatory compliance and provides customer and connection data used in asset management planning.
Customer relationship management platform	Our CRM platform manages connection applications, customer interactions, quality-of-supply complaints, and fault and outage management. Customer data held here informs network planning, connection capacity assessments, and service delivery performance monitoring.
Finance system	Our finance system provides financial management, asset valuation, regulatory disclosure reporting, and project cost tracking. It integrates with the asset management system to capture work order costs and supports investment decision-making through financial data on asset expenditure and lifecycle costs.
Outage and reliability system	Our outage and reliability recording system captures fault interruption and duration data across the network. It is the system of record for calculating and reporting on reliability performance measures including SAIDI and SAIFI, and provides the data used in network performance monitoring and reliability improvement programmes.
Integration platform	Our integration and API gateway platform manages the flow of data between systems, eliminating manual re-entry and ensuring consistent data across the enterprise. It is a foundational enabler of system integration and the movement of asset and operational data between our GIS, asset management information system, ADMS, data analytics platform, and other business systems.

8.5.7.3 Controls to ensure the quality and accuracy of asset management information

We have established a multi-layered approach to ensure the quality and accuracy of our asset management information, underpinned by the data governance framework described in Section 8.5.9. The key operational controls are:

- **Data standards**: documented standards govern how data is defined, captured, stored, and maintained across Orion. These standards specify required data attributes, acceptable value ranges, coding conventions, and update obligations for each asset class. They are used to configure data fields in our systems and to assess compliance during audits.

- **Data quality monitoring**: the Asset Information team runs ongoing monitoring and reporting on data quality metrics across our key data sets. This includes automated checks within our data analytics platform that identify missing, inconsistent, or out-of-range values. Regular reports on data quality are produced and reviewed, with identified issues escalated to data owners for remediation.
- **Cross-system consistency checks**: automated processes monitor for discrepancies between systems that should hold consistent data – for example, ensuring that the technical attributes of an asset are consistent across the asset management system, GIS, and operational systems. Automated alerts are generated when inconsistencies are detected, triggering investigation and resolution by the relevant data steward.
- **Master data management**: authoritative reference data – including equipment catalogues, asset hierarchies, geographic coordinates, and customer details – is maintained in controlled master data repositories. Changes to master data follow formal change management processes with appropriate approvals, preventing the proliferation of conflicting versions across systems.
- **Operational capture controls**: field processes are designed to capture data accurately at the point of work. Work completion processes require verification that physical installations match system records. Mobile tools enable real-time updates, reducing the risk of transcription errors or delays. Service delivery partner contracts specify data quality expectations as performance criteria.
- **Audit and clean-up programmes**: regular audits of key data sets identify systemic issues and inform targeted data clean-up campaigns. These are prioritised based on the criticality of the data to operational, investment, and regulatory outcomes. Our Asset Information team maintains a forward programme of improvement activity and tracks progress against defined quality targets.
- **Information security controls**: access to asset management information systems is controlled through role-based permissions, ensuring that only authorised users can view or modify data. System-generated audit trails record changes to critical data fields, supporting accountability and enabling investigation of data anomalies. Our cybersecurity approach, described in Section 8.5.5, protects the integrity of data against both internal and external threats.

8.5.7.4 Integration of systems, processes and controls

Our systems, processes and controls are partially integrated today, with integration improving progressively through our ongoing investment programme. The current state and direction of travel are as follows.

Many of our information systems operate through a data integration layer that connects systems and enables reporting and analytics across our asset management processes. Our modern data platform serves as the centralised repository into which operational, asset, customer, and financial data flows from across the enterprise, providing a consistent and accessible data set for analysis and decision-making. Our integration platform manages the movement of data between systems, ensuring that data entered in one system is automatically propagated to others without manual re-entry.

However, our asset information systems have evolved organically over time and some remain only partially integrated. Data flows between certain systems still rely on batch transfers or manual reconciliation rather than real-time automated exchange. This fragmentation can lead to temporary inconsistencies between systems and requires ongoing manual oversight to detect and resolve discrepancies.

Addressing this is a central objective of our IAM programme and our broader integration platform investment. The IAM programme establishes a single source of truth for asset data, with automated interfaces to our GIS, ADMS, finance system, and data analytics platform. Once fully implemented, this will substantially reduce the manual reconciliation effort currently required and improve data consistency across the enterprise. The integration platform programme is simultaneously modernising the connectivity between all our core systems, replacing legacy point-to-point interfaces with a managed, standards-based integration architecture.

Our governance processes are also integrated in the sense that data quality monitoring, master data management, and security controls apply across all systems within scope of our data governance framework. The Architecture Governance Group and the Data Governance Group provide enterprise-wide oversight, and data stewards operate across business units to ensure consistent application of standards. This governance layer means that controls are not applied in isolation on a system-by-system basis but are coordinated across the information landscape.

8.5.8 ICT renewal management

We manage ICT infrastructure with the same lifecycle discipline applied to our network assets. This approach ensures reliable operation of the technology platforms that underpin both our network operations and business functions.

We maintain detailed inventories of all infrastructure components, track their age and condition, and plan replacements before systems reach end-of-life. This prevents the ‘technology debt’ that can accumulate when systems are run beyond their supported life, ensures we can implement security patches and upgrades without compatibility issues, prevents unexpected failures, and ensures we maintain vendor support for critical systems.

Comprehensive monitoring tools provide visibility into infrastructure health and performance, enabling us to identify and address issues before they impact operations.

We continuously assess capacity requirements against business growth and new system demands, ensuring infrastructure scales appropriately without over-provisioning.

Our ICT infrastructure represents a significant ongoing investment, with costs transitioning from predominantly capex to a mix of capex and opex as we adopt more cloud and subscription-based services.

We carefully monitor and forecast these costs, seeking opportunities for consolidation and efficiency while ensuring infrastructure remains fit-for-purpose.

8.5.9 Data governance

The identity and integrity of our data is critical as we make operational decisions affecting thousands of customers based on this data, and regulators and auditors rely on the data we provide. Poor data quality or compromised data security could lead to incorrect decisions, regulatory non-compliance, or loss of stakeholder trust.

Strong data governance ensures we deliver value while managing associated risks through:

- **Data ownership and stewardship**: we have established clear accountability for data quality, with designated data owners for each major business domain and data stewards responsible for maintaining quality standards.
- **Data standards**: documented standards govern how data is captured, stored, and shared across Orion, ensuring consistency and interoperability.
- **Data quality monitoring**: regular monitoring and reporting on data quality metrics enables identification and remediation of issues before they impact decisions or operations.
- **Information security**: comprehensive security controls protect sensitive business and customer data, including access controls, encryption, and monitoring for unauthorised access.
- **Regulatory compliance**: our data management practices ensure compliance with privacy legislation, regulatory disclosure requirements, and information retention obligations.

- **Master data management**: we maintain authoritative reference data, such as equipment catalogues, customer details, geographic coordinates, and asset hierarchies, in controlled master data repositories. Changes to master data follow formal change management processes with appropriate approvals. This ensures consistency across all systems that consume this data and prevents the proliferation of conflicting versions that can undermine decision-making.
- **Cross-system data quality**: one challenge in a complex systems environment is maintaining consistency across systems. For example, an asset's technical specifications should be identical in our asset management system, geographic information system, and operational systems. Our data quality monitoring specifically checks for any cross-system discrepancies, with automated alerts when inconsistencies are detected and formal processes to investigate and resolve them.

By treating business systems and data as strategic assets requiring active management, we ensure our technology investments deliver enduring value to Orion and customers. The specific operational controls through which this framework is applied to asset management information are described in Section 8.5.7.

8.6 ICT modernisation

8.6.1 Evolving to meet future needs

The changing energy landscape and our growing network complexity require capabilities that go beyond what our current systems were designed to provide. Our challenges and improvements are set out below:

- **Enhancing integration**: asset information is currently located across multiple specialised systems, each optimised for specific business functions. As our network becomes more complex with DER and two-way power flows, we see value in creating stronger connections between these systems to enable more seamless data flow and consistency.
- **Supporting more dynamic operations**: we need systems that can support faster decision-making, predictive insights, and scenario planning as network complexity grows. This requires real-time visibility and analytical capabilities beyond our current architecture.
- **Enabling efficiency gains**: data reconciliation and entry across systems, while manageable today, represents an opportunity to free up skilled staff for higher-value activities. Better integration and automation will reduce effort while improving data quality and consistency.
- **Meeting evolving expectations**: regulatory and business requirements for asset information transparency continue to grow, and stakeholders increasingly expect sophisticated analytics and reporting. Modern, integrated systems will make it easier to meet these expectations efficiently.
- **Leveraging data as an asset:** we collect substantial asset and operational data that contains valuable insights. Enhanced analytics capabilities will help us identify patterns, predict asset health issues earlier, and optimise investment timing across our asset base.

8.6.2 Integrated asset management programme

The opportunities for enhancement listed above have driven our strategic focus on the IAM programme, one of our most significant ICT investments and fundamental to achieving our strategic objectives.

The IAM programme will transform our asset management platform into an advanced, integrated system incorporating predictive maintenance, safety management, automated inspections, and strategic investment planning tools. These capabilities are essential for enabling better investment decisions through integrated risk and value assessments, improved asset performance, enhanced safety, and support for our broader network transformation objectives.

At its core, the programme establishes a single 'source of truth' for asset data, eliminating the fragmentation that has historically challenged our ability to maintain data consistency and generate integrated views of asset performance.

The system will integrate with field operations through mobile capabilities, enabling real-time work order management, asset updates, and condition assessments by field workers. Critically, the programme includes comprehensive LV network data and integration with operational systems, providing the detailed connectivity information needed for advanced capabilities, such as automated fault location and DER management.

We are implementing the IAM programme through a phased approach that balances our end goal with deliverability.

- Phase 1 will be completed in FY27. It will establish the foundational platform and contain migrated core asset data.
- Phase 2, programmed for FY27 to FY28, will expand capabilities including advanced analytics, predictive maintenance, and enhanced mobile and integration capabilities.
- Phase 3, programmed for FY28 to FY30, will deliver the remainder of the programme, including strategic investment planning tools and comprehensive lifecycle management.

This incremental approach delivers tangible value at each phase. It allows us to realise benefits progressively, adjust based on lessons learned, manage change effectively across Orion, and trial concepts and new asset data acquisition and analysis tools before full-scale deployment.

8.6.3 Analytics and reporting

We have deployed modern reporting tools across our business intelligence platform, providing self-service analytics capabilities to staff across Orion. This enables faster access to insights and reduces reliance on centralised reporting teams.

Box 8.1 From data to decisions

Strategic Data Applications

Our data management capabilities enable several high-value use cases:

- **Asset performance analytics**: by combining asset data from our asset management system with operational performance data, we can identify patterns indicating early-stage failures, optimise maintenance timing, and target investments to assets with highest failure risk or consequence.
- **Load forecasting and network planning**: historical load data combined with customer growth projections, electric vehicle uptake models, and DERs registrations enables more accurate network capacity planning and investment prioritisation and optimisation.
- **Outage analytics**: detailed analysis of outage causes, durations, and response times helps identify systematic issues and opportunities for reliability improvements. This analysis informs both operational procedure changes and targeted asset interventions.
- **Regulatory reporting**: automated extraction and calculation of regulatory metrics reduce the effort required for compliance reporting while improving accuracy and auditability.

8.6.4 Artificial Intelligence

We are developing AI capabilities that analyse network data to predict equipment failures, optimise maintenance scheduling, and support operational decision-making. Our AI governance framework ensures these tools are deployed securely, ethically, and in alignment with our business objectives.

Current and planned AI applications include:

- predictive asset health models that analyse condition data, maintenance history, and operational stress to forecast failures

- computer vision systems that analyse drone and ground-based imagery to identify vegetation encroachment, equipment damage, or security concerns
- natural language processing to extract insights from unstructured text in inspection reports and maintenance logs
- optimisation algorithms that determine optimal switching configurations or maintenance schedules
- chatbot capabilities for customer service that can answer common queries and route complex issues appropriately.

We are taking a measured approach to AI adoption, starting with pilot projects that prove value before scaling deployment. Each AI application undergoes rigorous testing to ensure accuracy, bias assessment to ensure fairness, and ongoing monitoring to verify continued performance.

An example of how we are bringing multiple capabilities together in practice is a pilot on the use of drones and computer vision to inspect network assets.

Box 8.2 Smarter inspections with drones and AI

Our drone and AI project

We are using drones fitted with cameras and AI software to gather more accurate, up-to-date information about our equipment. Early trials have shown we can:

- fix outdated location records
- check the condition of power lines from the air
- automatically identify different parts of power poles.

This approach means our crews spend less time working at heights or near busy roads, we can analyse information faster, and we are building a photographic library of our network that we can refer back to whenever needed.

What this means for customers: safer maintenance work, more reliable power supply, and fewer disruptions from site visits.

What this means for our teams: better quality data, solid evidence to support decision-making, and a foundation for connecting this information with our existing mapping and asset tracking systems.

What's next: We are now focusing on building systems that can handle larger amounts of data, improving our AI accuracy, and making sure there is always expert human oversight to check the results as our photo library grows.

8.6.5 Other ICT modernisation

In addition to the IAM programme, we are in the process of undertaking a comprehensive technology modernisation programme that addresses both essential system renewals and capability enhancements across our entire ICT environment. Two of the main areas we are focused on are:

- **Operational technology transformation**: we will enhance network control capabilities through ADMS upgrades and smart switching equipment in substations. An example of increased smart switching is shown in Box 8.3. We are also working to commission an ADMS simulator in FY27, which will allow us to programme scenarios and test our contingency plans in a "live" training environment.
- **Customer-facing systems**: we have already modernised our customer-facing systems, including our customer engagement platform and billing system, enabling more proactive communication and better service delivery. We will continue with our modernisation in this area.

These improvements are focussed on our ICT systems; for broader asset management improvement initiatives, refer to Section 18 – Asset management improvement.

Box 8.3: Smart switching: faster power restoration for customers

Smart technology keeps the lights on

In September 2025, Orion became the first electricity distribution business in New Zealand to implement Primary Outage Restoration Tool (PORT) on our network management system – one of only a handful of networks worldwide to do so.

PORT builds on our existing Automated Power Restoration System (APRS), which has long been able to locate faults on individual 11 kV feeders and automatically restores customers in around 30-seconds. PORT operates at the next level up: when a subtransmission supply failure affects an entire substation, PORT automatically coordinates switching across multiple feeders simultaneously, restoring supply to as many customers as possible within minutes – leaving only the faulted area without power.

The practical benefits were demonstrated quickly. Only weeks after implementation, a vehicle struck a pole, cutting power to 231 customers. Using traditional methods, restoration would take 15-20 minutes. With our new automation, we restored 213 customers in approximately one minute, with the remaining 18 were reconnected once repairs were completed that evening.

Beyond the direct customer benefit, PORT reduces pressure on our network controllers by automating some of the complex switching decisions needed to restore supply, allows our teams to focus on repairing faults rather than locating them, and reduces the need for network operators to travel to remote sites.

8.6.6 Asset data integrity and quality improvement

The value we derive from our asset information systems depends on the quality and integrity of the underlying data. While Section 8.5.7 describes the controls we have in place today to maintain data quality, this section describes our forward-looking programme to improve data integrity over the AMP period.

Poor data quality causes operational errors, maintenance inefficiency, suboptimal investment decisions, regulatory compliance risks, and project delays. The following limitations in our current asset data are acknowledged:

- **LV network data**: our low-voltage network data has historically been less complete and less accurate than our high-voltage network data. Connectivity, phasing, and service fuse information for LV assets contains gaps that limit our ability to undertake automated fault location and DER management on the LV network.
- **Cross-system consistency**: the same asset may carry different attribute values in different systems due to updates being made in one system but not propagated to others. This requires ongoing manual reconciliation and can cause temporary inconsistencies in analysis and reporting.

- **Asset condition data**: condition assessments for some older asset classes are incomplete, either because formal condition assessment programmes were not in place when those assets were installed, or because assessment records have not been fully migrated into current systems. This limits the precision of condition-based risk modelling for those asset classes.
- **Data capture timeliness**: in some cases, asset records are not updated promptly following field work, particularly where work is completed by service delivery partners. This means system records may temporarily lag the physical state of the network.

Improving data integrity requires coordinated efforts across our technology types, processes, and people. Our improvement strategy includes:

- **System consolidation**: the IAM programme establishes a single authoritative system of record, eliminating inconsistencies from our maintaining parallel datasets, and ensuring geographic and connectivity data remains synchronised across all systems.
- **Data governance**: our data governance framework, described in Section 8.5.9, establishes data ownership, documented standards, quality monitoring, and formal change control processes for critical data.
- **Operational excellence**: field processes ensure accurate and timely data capture through mobile tools, enabling real-time updates rather than delayed paper-based transcription. Work completion includes verification that records match physical installations. Regular audits will identify any systemic issues, with targeted clean-up campaigns addressing specific problems. Our arrangements with service delivery partners will specify data quality expectations as performance criteria.
- **Lifecycle integration**: data quality will be embedded throughout the asset lifecycle, from planning and design through construction, operations, maintenance, and eventual decommissioning, ensuring every interaction with an asset triggers appropriate record updates.
- **Workforce development**: all staff who interact with asset data will receive training on quality expectations and proper system use. We are fostering a culture where data quality is everyone's responsibility, supported by dedicated Asset Information Analyst and Data Engineer roles providing expertise and guidance.

By treating asset data integrity as a strategic priority, supported by technology, governance, processes, and skilled people, we will ensure our asset information systems deliver full value internally on and to customers.

8.6.7 Business systems

As noted above, independent third-party reviews confirmed that several key platforms pose growing failure risks and cannot adequately support future operation requirements.

We are in the process of upgrading or replacing many of our core business systems to avoid reliability risks and enable the sophisticated data management, analytics, and integration capabilities needed for managing an increasingly complex network.

So far, our modernisation programme has replaced or substantially upgraded several of these systems, enabling them to operate as an integrated ecosystem rather than in isolation.

Our core business systems are set out in the sections below.

8.6.7.1 Financial management

Our finance system manages financial planning, reporting, regulatory disclosures, and treasury functions. We have recently replaced our legacy end-of-life finance system with a modern platform that provides enhanced financial management capabilities, improved reporting, and better integration with other enterprise systems.

8.6.7.2 Customer engagement

Our Orion Online Services portal provides customers and electricians with a secure, self-service interface to transact directly with us. Through the portal, customers can apply for new connections, disconnections, and alterations to existing connections, connect distributed generation to the network, and sign up for planned outage notifications by email and text. Our Connections team uses a Customer Relationship Management (CRM) tool to manage connection applications from initial request through to completion.

Our 24/7 Customer Support team handles more than 1,800 calls monthly. Customers can also view current and planned outages through our real-time outage map, and report faults directly through our website. All customer complaints are recorded in our Incident Management system, ensuring a complete record of each interaction and enabling consistent resolution across our team.

We are progressively enhancing self-service capabilities to give customers more control and reduce the need for phone interactions.

8.6.7.3 Billing and registry management

We have recently replaced our legacy billing system with a modern vendor-supported platform that handles customer billing, registry management, and regulatory reporting. This platform provides enhanced accuracy, automation, and flexibility to support evolving regulatory requirements.

8.6.7.4 People and capability systems

Our HR and learning management systems support workforce development, performance management, and capability uplift initiatives. We are establishing a Learning Centre of Excellence that uses modern learning management platforms to deliver:

- role-based competency frameworks and training pathways
- on-demand access to technical training and safety procedures
- tracking of qualifications, certifications, and compliance training
- analytics on capability gaps and development needs across Orion.

These systems are essential to ensuring our workforce can effectively operate and maintain increasingly sophisticated network and digital assets.

8.6.7.5 Telephony and communications

Our telephony infrastructure supports both customer interactions and internal communications. We are modernising this infrastructure to ensure we continue to provide:

- intelligent call routing based on customer needs and staff availability
- integration with customer engagement systems for automated information delivery
- unified communications capabilities combining voice, video, and messaging
- detailed analytics on call volumes, wait times, and resolution rates.

8.6.7.6 Document and knowledge management

We manage substantial volumes of technical documentation, standards, procedures, and corporate records. Our document management requires modernisation and consolidation given the criticality of the information held and to ensure this information is accessible, version-controlled, and properly retained in accordance with regulatory and business requirements. This represents another legacy system area requiring strategic investment.

9

9. Transforming our network

We are transforming our network to fundamentally change how we plan and operate the distribution system in response to evolving customer needs and expectations in relation to the energy transition. Our network transformation work did not begin with this AMP period. Over the last few years, we have been building the foundations by procuring smart meter network operational data, piloting flexibility services, and investing in the systems and analytical capability needed to manage a more complex network.

These early years were necessarily set-up years: developing governance frameworks, commercial models, operational processes, and the internal capability required to move from concept to delivery. That groundwork is now sufficiently mature for us to scale. Through the CPP period from FY28, expenditure in this section increases as both programmes shift from foundation-building to active delivery, which will see us procuring non-network solutions, deploying a distributed energy resource management system (DERMS), expanding network monitoring coverage, and embedding flexibility into our standard planning and investment processes.

Through our Network Transformation programme (see Section 9.3) and our Flexibility and Markets Development programme (see Section 9.4), we are moving towards an approach that integrates asset management, network planning, and real-time operations with active customer participation. The innovation practices that inform and feed into these programmes are described in Section 9.5.

This transformation will enable customers to play a direct role in their energy journey, including through providing non-network solutions to potentially defer the need for network investments, while ensuring our network remains safe, reliable, and cost-effective.

By aligning new technologies, market mechanisms, and operational practices with the challenges and opportunities facing our community, we are ensuring the network does not become a barrier to decarbonisation. Instead, we are enabling a network that supports choice, innovation, and shared value, helping to power a cleaner, brighter future with our community.

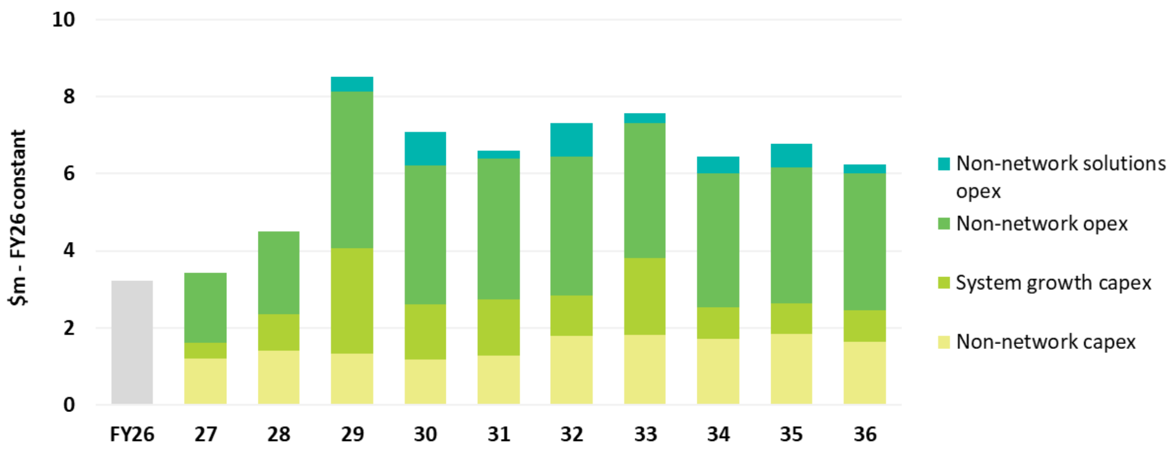
For customers, network transformation has a direct and practical meaning. As electric vehicles, solar panels, and battery storage become more common in Central Waitaha Canterbury homes and businesses, customers are increasingly both consumers and producers of electricity. Our network must support them in both roles: supplying electricity safely and reliably when demand is high, and accommodating export back to the network when customers generate more than they need.

Beyond simple two-way flow, we are developing the capability to reward customers for actively helping to manage the network: for example, by incentivising battery owners to export during peak demand periods, or EV owners to charge during off-peak times when the network has capacity to spare. This reduces the need for expensive infrastructure investment that all customers would otherwise pay for.

9.1 Investment overview

Our network transformation investment totals $64.5 million over the FY27-FY36 period, comprising $36.8 million in opex and $27.6 million in capex. This investment supports our network's evolution to accommodate two-way energy flows and integrate distributed energy resources (DER). Figure 9.1 shows the total proposed investment per annum.

Figure 9.1 Orion's Network Transformation investment per annum, by component



Investment increases in FY29 are driven by additional system growth capex and non-network solutions opex as we scale non-network solutions to address identified network constraints. Our expenditure then stabilises over the remainder of the AMP period.

The expenditure contained within this section relates to the activities undertaken by the Network Transformation and Flexibility and Markets Development programmes. Our expenditure comprises:

- **System growth capex**: network equipment to support DER connections and manage increased network complexity and demand, such as community batteries, microgrids or pole-type or kerbside batteries to support DER growth and network resilience.
- **Other non-network capex**: the trial and implementation of technology platforms, systems, data and tools that enable network visibility, advanced analytics, and operational capability, such as DER management systems and bulk LV analytics tools.
- **Non-network opex**: ongoing operational costs of new systems and technology platforms and other data related costs, such as operational data from smart meters and ongoing software licenses.
- **Non-network solutions opex**: commercial arrangements with flexibility service providers to manage network constraints without building traditional new infrastructure. Specific network development projects that address capacity and security constraints are detailed in Section 12 – Network development programme.

This expenditure is linked to three of our investment priorities: preparing for future energy needs, enhancing our efficiency and capability, and supporting strong population and demand growth. The non-network solutions opex represents systematic consideration of non-network solutions in our planning process, as described in Section 10 – Network development approach.

We will continue to apply to the Commerce Commission for Innovation and Non-Traditional Solutions Allowances (INTSA) for eligible innovation project costs during the remainder of the DPP4 period, and have requested continuation of the INTSA framework in our CPP application.

9.2 Overview and strategic context

Transforming our network means ensuring we are ready and equipped to support customers who are connected or connecting to our network in their energy transitions. This requires us to understand the global and regional trends driving change, and reshaping how electricity is generated, distributed, and used, and to plan our network accordingly.

Our network transformation is directly influenced by four global industry megatrends (Decarbonisation, Digitalisation, Decentralisation, and Democratisation) and several other key regional trends. These factors significantly impact the energy transition and electrification in New Zealand and change how electricity distribution businesses (EDBs) plan and operate their networks.

These drivers have a direct impact on our investment choices and how we plan for the future. The drivers identified in Figure 9.2 are all responsible for changing how we think about access to, and utilisation of, the electricity system. Because EDBs are the interface between electricity users and the system itself, we must be particularly aware of social and technological changes and the resulting changes in customer behaviour. This is particularly true as electricity generation decentralises and customers begin to utilise the distribution network in both directions.

While this represents a challenge to the historical operating methods of EDBs, it also provides an opportunity to put customers at the centre of decision-making within Orion. The two programmes described in this section are focused on achieving improved customer outcomes and experiences, and ensuring we are ready for changes before they appear, with customers remaining central to our approach.

Figure 9.2 Orion's network transformation drivers

1. Customer drivers

- Energy security
- Energy equity
- Optioneering
- Customer centricity
- Customer as 'Prosumer'

2. Business drivers

- Investment optimisation
- Asset optimisation
- Operational automation
- Predictability
- Business model change

3. Demand and decarbonisation drivers

- Industry electrification
- Electrification of transport
- Intensified infill housing
- Utility-scale solar
- Sustainability

4. Regulatory drivers

- The Commerce Act (Part 4)
- The Electricity Industry Act
- Electricity Industry Participation Code (the Code)
- Civil Defence and Emergency Management Act
- Health & Safety at Work Act

5. Technology drivers

- Affordable solar and increasing uptake
- Network digitisation and insights
- Home and utility scale energy storage
- Smart appliances and heat pumps
- Accelerated EV uptake and smart charging
- Remote surveillance

9.2.1 Two complementary programmes

Our network transformation is driven by two discrete but complementary programmes of work that lead and support Orion in driving this change:

1. **Network Transformation Programme**: focuses on network-based transformation including investigating, developing, and implementing new technologies, systems, and processes that enable continued delivery of line services in a changing energy environment. Investment in this programme ensures the distribution network is ready for the changes a decentralised, democratised, and digitalised energy landscape will bring.
2. **Flexibility and Markets Development Programme**: focuses on market and customer-enabled transformation, including developing and coordinating flexibility to deliver efficient and reliable outcomes for connected parties, our network, and the wider electricity system. This programme will develop commercial, system, and service-level capabilities required to enable flexibility where and when it is needed.

These programmes position Orion to facilitate decarbonisation, empower customers, and deliver enduring value at the lowest long-term cost, with each programme's focus split between network-based activities and customer or market-enabled activities respectively.

9.3 Network Transformation Programme

This programme investigates, develops, and implements new technologies, systems, and processes that will enable Orion to deliver line services that customers expect in a changing energy environment. The programme focuses on enabling the connection and utilisation of emerging and existing technologies through updated visibility and understanding of the distribution network.

Investment in this programme will ensure the distribution network is ready for the changes a decentralised, democratised, and digitalised energy landscape will bring. It ensures that we can continue to enable the energy transition and are capable of adapting to the increased scale and pace of change within consumer behaviour and electrification.

This programme delivers the Network Transformation Roadmap through five workstreams centred on strategic planning, operational capability development, connection process improvement and technology trials, power systems insight, network data integration, and business change enablement. These workstreams have been combined into four categories to group expenditure related to the main aspects of transforming our network. The outcomes delivered through work in these categories aligns with customers' expectations and CPP drivers, particularly preparing for future energy needs. These categories are described below in Table 9.1.

Table 9.1 Network transformation programme investment categories FY27-FY36 ($m, FY26 constant)

Investment category	Key initiatives	System growth capex	Non-network capex	Non-network opex	Non-network solutions opex
Visibility *Building foundational structures that improve connection and operation processes through data acquisition, network modelling, and bulk analytics that provide actionable insights*	Deployment and licensing to support deploying LV network monitoring	4.0	-	2.6	-
	Developing an LV model	-	0.3	1.6	-
	Acquiring network data, including smart meters	-	12.3	10.9	-
	Improving Internet of Things (IoT) device telemetry and communications	2.3	-	0.2	-
	Increasing network analytics capability	-	-	9.7	-

Table 9.1 Network transformation programme investment categories FY27-FY36 ($m, FY26 constant)					
Investment category	**Key initiatives**	**System growth capex**	**Non-network capex**	**Non-network opex**	**Non-network solutions opex**
	Other	-	-	0.8	-
Growth and connections *Investigating and deploying network-based technologies that improve customer outcomes and enable efficient investment decisions beyond traditional poles-and-wires solutions*	Exploration of battery energy storage systems for capacity management	3.3	-	0.5	-
	Exploration of microgrids and community energy hubs for resilience and capacity improvements	2.4	-	-	-
	Improving network automation and optimisation	0.5	-	0.9	-
	Procurement of flexible resources for demand side management	-	-	-	3.8
	Other	-	-	0.5	-
Operations *Technology and software improvements that enable operation with improved network visibility and understanding, including the control systems required for a changing energy landscape*	Improving network operational tools	-	-	1.6	-
	Developing and deploying active network management systems (DERMS)	-	2.7	3.8	-
Business change *Ensuring operating practices and workflows keep pace with changes across the other investment categories*	Process, standard, and procedure development or redesign	The expenditure involved in business change is captured in SONS & business support. See Section 8 – People & technology for further details.			
	Training and capability development programmes				
	Change management activities				
Total		**12.5**	**15.3**	**33.1**	**3.8**

9.3.1 LV network monitoring practices

Effective monitoring of our low voltage network (LV) is essential to understanding network performance, identifying constraints, and maintaining service quality as customer behaviours and technologies evolve. Over recent years, we have made significant progress in building the data foundation required to manage an increasingly complex low voltage network through several sources of data.

9.3.1.1 Progress in data procurement and monitoring deployment

Understanding how electricity actually flows across our LV network, in real time, at a customer level, is the foundation for most of the capability described in this section. Without this visibility, we cannot reliably identify emerging capacity constraints before they cause problems, enable demand-response programmes that reduce peak loads and defer traditional investment, or give customers accurate, timely information about outages and power quality. Smart meter data, with targeted LV monitoring, is the most cost-effective way to gain this visibility at scale. Relying solely on physical LV monitoring equipment would cost more per coverage point and provide less resolution, whereas relying solely on smart meter data would provide inaccurate results and uncertainty in analysis. Investing in smart meter network operational data and targeted LV monitoring deployment is therefore both the least-cost and highest-value path to understanding and managing our network in the customer's interest.

In October 2023, Orion became the first EDB in New Zealand to secure access to smart meter Network Operations Data (NOD) from Bluecurrent, New Zealand's largest smart meter provider. This agreement covers approximately 90% of our customer connection points. This data is provided on an overnight basis and is unlocking capability around proactive low voltage constraint identification and network management.

However, there is still a significant challenge in procuring smart meter data from other metering providers to achieve full network coverage due to contractual and financial considerations. Current service offerings vary between metering equipment providers. Although functionality to provide near real-time smart meter event and status information is now becoming available, these services come at significant additional costs and come with conditions requiring minimum meter quantities to be purchased. This reduces the cost-benefit of procuring this data for our customers.

Where smart meter data is unavailable, we use LV monitoring equipment to compensate for this gap. However, LV monitors also have installation, operating and maintenance costs and cannot fully cover the use cases serviced by smart meter NOD. While historical consumption data has some utility in informing network capacity constraints, it is generally of lower resolution than NOD and cannot provide a full picture of network performance.

Other than smart meter data, there are several other data sources which are required to forecast growth in load and generation and subsequent constraints at a LV level. These include more granular data on electric vehicle uptake, more accurate and higher resolution council growth figures, council building consent applications and development plans, and data from EV chargers and inverters to understand behaviour. See Section 10 for further discussion on our demand forecasting approach.

9.3.1.2 Analysis and modelling approaches

Orion currently uses LV analytics platform Future-Grid Compass to process smart meter NOD and LV monitor data for general business use. The platform supports both voltage quality monitoring, described further in Section 5.1.4, and constraint analysis for general network planning.

More bespoke analysis and modelling such as network optimisation, hosting capacity calculations and scenario analysis is undertaken in-house to inform medium and long-term planning. There are several challenges and limitations around both analytic approaches including:

- lack of full smart meter data coverage
- limited data around low voltage customer phasing and service mains
- integration of data into network models
- the magnitude of computation required.

We are developing data handling, modelling and analysis methodologies to mitigate the impacts of these limitations where possible and quantify the level of accuracy that can be expected.

For further discussion on our approach to identifying LV constraints, refer to Section 11 – Network demand, distributed generation, and constraint forecasts.

9.4 Flexibility and Markets Development Programme

We are committed to enabling and optimising the use of non-network solutions across our network. This programme is centred on developing and coordinating demand-side flexibility. Demand-side flexibility is the ability to adjust electricity demand in response to the electricity system's needs or signals, to deliver efficient and reliable outcomes for connected parties, our network, and the wider electricity system.

Flexibility can provide value across the electricity supply chain including through the wholesale market, ancillary services, transmission and distribution networks, and to customers. This is known as "value stacking." Coordination of flexibility across the supply chain in both planning and operational timeframes is critical to maintaining security of supply while supporting cost-effective decarbonisation.

This programme develops the commercial, system, and service-level capabilities required to enable flexibility where and when it is needed, while working closely with the Network Transformation Programme to build the operational capability required to integrate flexibility safely.

Table 9.2 Flexibility and Markets Delivery programme alignment to strategic focus areas

Strategic focus area	Purpose	Key initiatives
Utilised and accessible network	Enabling customer participation in flexibility markets to support electrification and renewable generation while managing network constraints.	• **Shared hot water control**: trialling value stacking through shared retailer control of 145,000 hot water cylinders. • **Resi-flex**: testing commercial mechanisms for reducing peaks with residential flexibility trials. • **Flexible connections**: allowing existing connections greater capacity outside of network peaks.
Safe, reliable, resilient network	Embedding flexibility into network planning and investment decisions as systematic alternative to traditional reinforcement.	• **Flexibility optioneering**: integration of non-network solutions into asset management and procurement processes. • **Load management protocol**: ensuring flexibility operates within safe limits (with Electricity Networks Aotearoa (ENA)). • **Distribution system operation alignment**: supporting advancements toward models for distribution system operation (with ENA).
Our community	Building capability and enabling informed participation in the energy transition through community and sector collaboration.	• **Scaled flexibility pilot**: working with industry and the community to trial residential flexibility at scale. • **Commercial and industrial demand flexibility project**: supporting our largest users to invest in and operate flexible energy solutions. • **Industry leadership**: building capability across the sector though knowledge sharing and active participation in the Flex and Future Network Forums.

9.5 Innovation practices

9.5.1 Our strategy and the role of innovation

Our network transformation is driven by two discrete but complementary programmes of work that lead and support Orion in driving this change:

Our changing operating context requires us to find smarter, more efficient ways to plan and operate the network, and to better enable our customers and community to participate in the energy transition. We approach innovation practically and with clear intent. We focus on areas where new approaches can deliver real customer value, whether that is through deferring capital-intensive network upgrades, reducing whole-of-life asset costs, increasing efficiencies, or enabling customers to participate more actively in the energy transition. Where benefits are clear, we move to adopt. Where they are not yet established, we explore, trial and learn.

Our innovation activity supports delivery across our investment programme, including our people and technology investments in Section 8 and our asset management approach in Sections 13 and 14. During FY26, we focused on four key themes:

- Data, digitalisation and AI, improving network visibility and insights through data and digital tools
- Non-network solutions and flexibility, enabling customer participation and deferring traditional investment
- Asset management excellence, modernising how we manage and maintain assets, and strengthening asset management decision-making
- Working with others, collaborating with other EDBs, technology providers, and communities.

For more information on projects we have completed or plan to begin in this AMP period, our flexibility trials, pilots or market engagement activities, see *Appendix H – Innovation activity at Orion,* and our website: https://www.oriongroup.co.nz/your-energy-future/innovation.

9.5.2 Data, digitalisation and AI

Improved data and digital tools, and artificial intelligence (AI) are foundational to Orion's innovation programme. With better visibility of what is happening on the network, particularly at the LV level, we can more confidently assess where non-network solutions could work, where assets are approaching risk thresholds, or how DER uptake is affecting loading and voltage.

In FY26, we strengthened our data platforms, expanded LV network visibility, improved digital workflows, and trialled analytics and AI tools for predictive insight and operational optimisation. The desired outcome is a network that is more visible, more efficiently managed, and lower cost to operate for customers over time.

Table 9.3 Data, digitalisation and AI activities

During FY26	Working towards
• Strengthened modern data platform foundations enabling improved system integration and expanded data capture (e.g. LV visibility and delivering IAM) • Improved digital workflows & automation, reducing manual effort and supporting more consistent decisions. • Improved visibility of DER and hot water flexibility through smart meter data. • Built organisation wide AI and innovation skills via workshops and tooling (e.g. AI agents for business improvement) • Embedded early AI capability for predictive insights and real-time operational optimisation (e.g. GridAware Tapestry trial)	• One source of truth for operational and innovation pilot data (clean, governed, sharable). [27] • Closed loop automation: detection → decision → action with safe human oversight. • IoT scale data ingestion & analytics supporting LV visibility, DER orchestration, regulatory reporting. • Interoperable data standards enabling exchange with retailers, Transpower, vendors, communities. • AI embedded everywhere – planning, outage response, maintenance, customer comms. • Controlled, secure AI adoption to reduce risk and accelerate operational excellence.

[27] Our IAM programme is the primary vehicle for improving asset data quality and integrating these systems. This is covered in detail in Section 8 of our AMP.

Box 9.1 Case study: FutureGrid Compass LV analytics

Leveraging capability obtained through the ViSION project to transition to proactive LV network management practices.

The situation

Connecting around 4,400 new customers per year efficiently requires visibility of what's actually happening on the LV network, which was historically one of our biggest blind spots. Our LV visibility was limited to 6-monthly transformer peak readings, with issue detection relying largely on customer complaints. Through BAU initiatives and the Visibility and Systems Insights for the Orion Network (ViSION) project, Orion has now deployed over 1,300 LV monitors and obtained data from over 200,000 smart meters. To turn this data into actionable insights, we required a unified analytics platform to combine this telemetry data with other LV datasets such as topology and asset specifications. This need drove our LV Network Analytics RFP which was awarded in Dec 2024 to Future-Grid.

What we explored

We assessed Future-Grid Compass by validating its core analytic functions, with a focus on phase identification accuracy, fault detection, LV loading behaviour and how well the platform reflected real network conditions. We also tested data-driven insights against confirmed issues to confirm where the platform performed strongly and where trigger messages, assumptions or confidence indicators needed clearer explanations.

The implementation also examined integration and deployment requirements in depth. This included aligning data structures, establishing reliable data-transfer workflows, and ensuring the platform operated consistently across environments.

Outcomes and learnings

The platform successfully entered production in 2025, giving our Network Development, Operations, and Connections teams greater situational awareness through improved circuit-level visibility, LV topology error detection, customer-phase insights, and more accessible load and voltage insights. The implementation also demonstrated that embedding a new analytics platform into everyday workflows requires structured onboarding and ongoing user feedback loops, not just the technical deployment.

What's next?

Orion plans to broaden Compass use cases across the business. Continuous user feedback to guide platform improvements is supported through drop-in sessions and a Quality Assurance (QA) register. Further work is planned to refine multi-phase identification, strengthen source topology accuracy, and improve load aggregation performance. Compass will continue to evolve as part of our Network Transformation Roadmap to support more automated, data-driven LV network management.

Impact on customers

Earlier fault detection, improved power quality, fairer and faster connection decisions, and a foundation for proactive, data-driven LV network management that reduces long-term network costs.

9.5.3

9.5.4 Non-network solutions and flexibility

One of our central aims over both the CPP and AMP periods is to increase our use of non-network solutions, including demand-side flexibility, DERs, and other alternatives to traditional network investment, to manage peak demand and defer or reduce capital investment (capex).

To do this at scale we need to understand how to support customers to participate in flexibility, what commercial mechanisms work to incentivise flexibility, and how we safely coordinate the operation of third-party flexibility providers across the network. The desired outcome is a reduction in peak demand that defers or avoids capital-intensive network upgrades, keeping long-term costs down for customers.

Box 9.2 Case study: commercial and industrial flexibility

A project to understand and trial the most effective ways to enable commercial and industrial customers to participate in flexibility.

The situation

As New Zealand's electricity systems decarbonise, the timing and location of peak demand is becoming as important as overall energy consumption, and we forecast peak demand on our network to grow by 31% over the AMP period. Managing this growth efficiently, and keeping costs down for customers, requires us to reduce peak demand through non-network means wherever it is cost-effective to do so. Commercial and industrial (C&I) customers are well placed to support this shift, given their scale and controllability.

Many of our largest C&I customers participate in our Control Period Demand (CPD) programme, which incentivise them to reduce load during network peaks. This provides demand response of around 18-20 MW during network peaks. This helps us to maintain a leaner, more efficient network.

However, the potential for broader C&I participation in flexibility, including customers outside the CPD programme and response outside control periods, was not well understood.

What we are exploring

We structured our work in three phases:

- **Phase 1: Discover and Define** (complete): Quantitative and qualitative research to understand C&I customer perspectives, barriers and enablers to deploying flexible energy solutions and the scale of potential flexibility across our network.
- **Phase 2: Enabling CPD Flexibility** (underway): Exploring C&I customers' capability for increased CPD response and testing operational enhancements to the CPD signal that can support broader adoption.
- **Phase 3: Beyond CPD** (planned): Engage with C&I customers and other flexibility stakeholders to activate and reward response outside of CPD (for example trialling flexible connections, or incentivising and supporting smaller customers to participate).

We are working with universities and schools, manufacturing plants, food processing plants, supermarkets, Christchurch City Council facilities, cool stores, aged care facilities and electricity retailers.

The staged approach reflects a deliberate decision to build evidence before committing to commercial mechanisms. Phase 1 findings informed the design and scope of Phase 2, including which customer segments and network locations offer the most value. Decisions on progressing to Phase 3 will be made based on Phase 2 trial results.

Outcomes and learnings

Phase 1 identified meaningful potential for increased flexibility from C&I customers, alongside clear barriers, including the complexity of existing electricity contracts and limited awareness of flexibility mechanisms. These findings shaped how we approached Phase 2 and informed our engagement strategy with C&I customers.

Impact on customers

Greater flexible capacity on the network, with less reliance on physical upgrades. C&I customers participating in flexibility programmes may benefit from lower lines charges and access to additional capacity without upgrade costs. Broader network customers benefit from reduced pressure on system growth investments.

9.5.5 Asset management excellence

Innovation supports our transition toward proactive, evidence-based asset management. As our asset base ages, and our information systems improve, we are developing better tools and approaches for condition assessment, maintenance planning and renewal sequencing to improve our ability to make risk-based investment decisions with confidence.

Improved data quality and new digital tools enable better-targeted investments, lower whole-of-life costs, and improve safety and resilience. As we become more data-driven, secure and reliable digital infrastructure is essential to support safe and efficient network operations, which is why our asset management improvement work is closely linked to our IAM programme and cybersecurity investments. The desired outcome is a safer, more reliable network managed at lower whole-of-life cost, with investment targeted where it delivers the greatest value for customers.

Further detail on our asset management improvement programme is set out within Section 18 of the AMP.

Box 9.3 Case study: Tapestry GridAware grid management and intelligence platform

Transforming the process of inspecting and maintaining equipment, leveraging drones and AI to handle inspections faster and more efficiently and gain new insights.

The situation

Maintaining the safety and reliability of an ageing network requires us to identify asset condition issues before they cause failures. A substantial portion of our network was built in the 1960s and 1970s and is approaching the end of its serviceable life. Traditional inspection methods are time-intensive and rely on periodic, manual assessment, which is a constraint that becomes more acute as the volume of assets requiring proactive attention increases.

Building on our drone imagery trials and Vector's GridAware trial, a consortium of four EDBs (Northpower, Orion, Unison Networks and WEL Networks) representing 25% of NZ customers, have come together to pool asset imagery and data to train an AI algorithm to identify an asset and correctly assess its condition through Tapestry's GridAware platform. The partnership addresses a practical constraint: individually, EDBs often lack the volume of labelled image data needed to effectively train AI for asset condition assessment across the full variety of equipment on their networks.

What we are exploring

Asset experts for each EDB will use GridAware to label thousands of examples of different types of assets (including different lines, poles, transformers, insulators, and cross-arms) and potential equipment defects. Collectively, the EDBs aim to contribute more than 10,000 labelled images identifying 10 unique types of grid assets and their condition over the next two years.

This collaboration will digitally teach Tapestry's software how to recognise maintenance needs for equipment used across the entire consortium. The participating EDBs will then be able to assess whether this innovative approach can provide intelligence that can help them more quickly and effectively maintain their grids and reduce outages in their communities.

Outcomes and learnings

The trial is live. Early results from Tapestry's ongoing work with Vector, who has successfully used the GridAware platform to demonstrate how AI can transform network management, are informing expectations for our own network. In August 2025, Vector released data showing that utilising GridAware enabled field assessment technicians to inspect roadside utility poles faster for the above ground proportion of the pole test.

Desired outcomes

Earlier identification of defective or aging equipment before it causes outages. Over time, more efficient inspection programmes and better-targeted maintenance and renewal activity, reducing the risk of unplanned outages and placing downward pressure on whole-of-life asset costs.

9.5.6 Working with others

A significant proportion of our innovation activity depends on collaboration. We work with other EDBs, sector organisations, industry forums, technology providers, regulators, customers, and communities. This is deliberate, as it allows us to share the cost of discovery, pool data where individual organisations lack scale, and build sector-wide capability rather than duplicating effort. Collaboration is an explicit objective of the Flexibility and Markets Development Programme, particularly through our engagement with Electricity Networks Aotearoa's (ENA) Future Network Forum (FNF) on load management protocols and distribution system operation alignment.

ENA represents all 29 lines companies across New Zealand. Through working groups and forums such as the FNF, we support ENA's collective efforts to help deliver a low-carbon future for New Zealanders, based on reliable, safe and affordable electricity networks. In FY26, we led or contributed to the Common Load Management Protocol project and the Streamlining Customer Connections working group. We also contributed to the ENA innovation process and portal project to improve collaboration and maximise value and visibility of EDB innovation activities.

The FlexForum is a cross-industry group formed to identify a set of actions to integrate distributed energy resources (DER) into the electricity system and markets to maximise the benefits for Aotearoa New Zealand. As a member of the FlexForum, we support coordination and collaborative action to enable a smart and flexible energy system. FY26 examples include hot water flexibility trials in partnership with our retail customers, and the Resi-Flex residential flexibility trial.

Further examples of how we have collaborated with other sector participants can be found in *Appendix H – Innovation activity at Orion*.

Box 9.4 Case study: Streamlining customer connections across the sector

Coordinating sector-wide change to make connecting to the electricity network faster, simpler, and more consistent for customers across New Zealand.

The situation

Connection requests are growing in volume and complexity across New Zealand, driven by new housing developments, distributed generation, battery storage, and rapidly increasing demand from EV charge point operators. The Electricity Authority, Electricity Engineers' Association (EEA), and ENA recognised that addressing this required coordinated action across three fronts: establishing national technical guidelines for network connections, removing price and non-price barriers through regulatory change, and co-designing customer service and commercial improvements that all EDBs could adopt to standardise and streamline the connections process.

What we did

We led the first phase of the ENA Future Network Forum's Connections Journey Mapping project, working collaboratively with 13 EDBs to improve the connections experience for customers across New Zealand. We began by meeting directly with charge point operators and large distributed generation customers to identify and understand their pain points when connecting to an EDB. Through that engagement, and working with all 29 EDBs, we developed a prioritised list of 13 deliverables to improve the connections journey from pre-application through to delivery.

The first six quick-win outputs have been finalised and released to all EDBs for implementation. These were developed by EDBs for EDBs, designed to allow each company to incorporate its own context while standardising where it matters most:

- connections glossary
- connections introduction guide for customers
- connection journey steps
- connections self-serve manual for EDBs
- pre-application meeting EDB manual and customer information template
- connections FAQ.

What comes next

We are now supporting Phase 2, which focuses on three workstreams:

- Standardised commercial contracts: covering novation, preliminary services agreements, and construction and delivery contracts for large load and distributed generation connections
- Queue management policy: developing key principles and a framework for an ENA-managed queue management policy across EDBs
- Capacity maps: researching overseas and New Zealand examples and engaging with customers to understand what they need, before developing a scoping report on implementation options.

Impact on customers

A more consistent, faster, and less frustrating connections experience across New Zealand, regardless of which EDB a customer is connecting to. Charge point operators, distributed generation developers, and residential customers all benefit from clearer processes, standardised documentation, and better upfront information on capacity and costs. Over time, capacity maps and queue management frameworks will give connecting customers greater certainty about where and when they can connect, reducing project risk and cost.

9.5.7 Sharing learnings across the sector

Under DPP3, the Commerce Commission's Innovation Project Allowance (IPA) scheme funded innovation projects across New Zealand EDBs, with participating businesses required to publish close-out reports on completed projects. Under DPP4, this has been replaced by the Innovation and Non-Traditional Solutions Allowance (INTSA) scheme.

Orion contributed to close-out reports for approximately 40% of all IPA projects with published learnings. This reflects the scale and breadth of our innovation programme relative to other EDBs, and the value of sharing what we have learned, which includes both positive findings and approaches that did not proceed to adoption.

We also actively consider learnings from other EDBs' innovation projects. Our intention going forward is to formally review published INTSA close-out reports on an annual basis, document how each informs or influences our own practices, and report on this as part of our annual innovation update.

9.5.8 Governance, decision-making and measuring success

Innovation at Orion is governed consistently with other business activity. Orion’s portfolio of innovation practices is guided by our strategic focus areas which are determined by our Board and Integrated Leadership Team. Governance of specific activities is devolved to the relevant Steering Committee for each focus area or programme depending on size and complexity.

In practice, innovation projects are overseen by:

- Programme or focus area Steering Committees, which provide oversight of specific innovation programmes and make decisions on whether to advance, pause or stop individual projects

  A cross-functional working group structure supporting each Steering Committee, which manages day-to-day delivery, monitors progress against defined milestones, and surfaces recommendations for Steering Committee decision.

This structure has evolved over the last two years to be more agile, moving from a single central Innovation Steering Committee toward governance that sits closer to where decisions are being made and where domain expertise resides.

How projects start

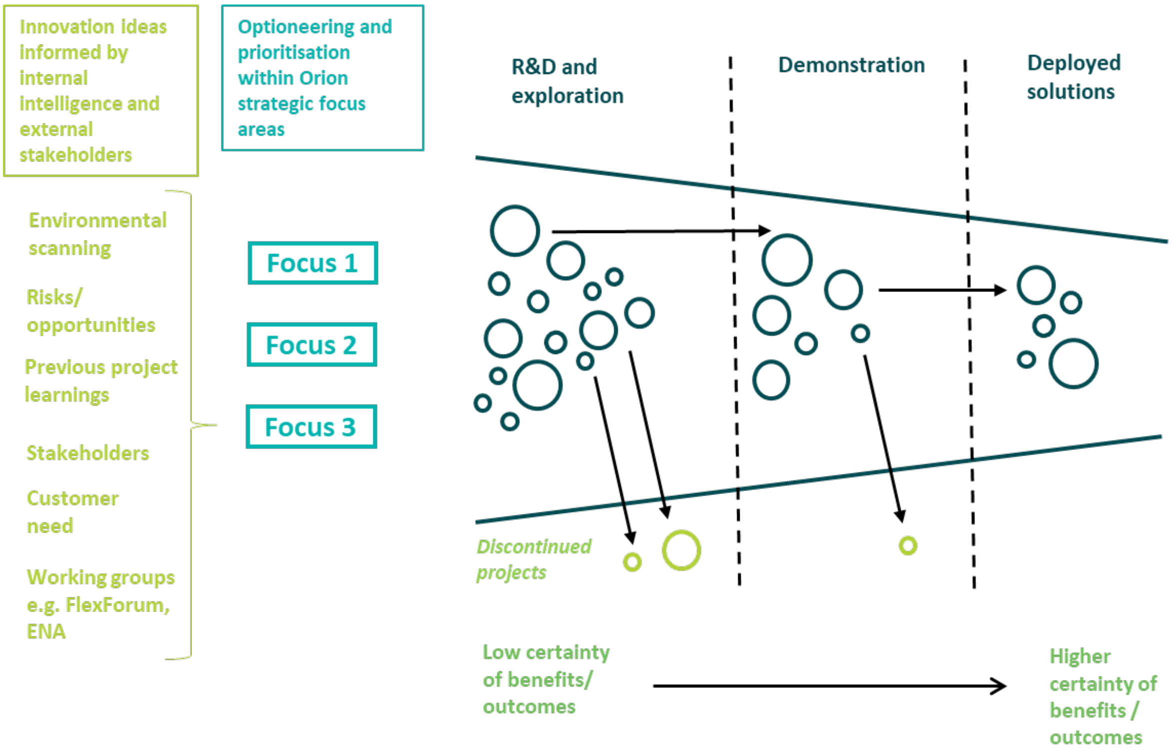
Ideas are developed in response to an identified challenge or opportunity in our operating environment. As illustrated in Figure 9.3, innovation ideas and project concepts are informed by environmental scanning, risks and opportunities, previous project learnings, stakeholder and customer needs, and external working groups.

After an idea is developed, a project concept is socialised for feedback from relevant Advisory Groups and Steering Committees.

A formal decision to commence a project is made by the relevant Steering Committee following confirmation that it aligns with our strategic focus areas and investment priorities.

Projects are generally structured in stages, including research and exploration, trial or demonstration, and deployed solutions, with defined milestones and decision points at each stage.

Figure 9.3 Orion's innovation pipeline – from ideas to deployed solutions



How decisions are made and measuring success

Decisions on whether to progress, pause, scale or stop innovation projects are currently made at the Steering Committee level, drawing on a combination of:

- trial evidence and post-project review findings
- customer outcome assessment: whether the initiative improves reliability, affordability, safety or customer choice
- operational feasibility: whether the solution can be integrated into our business at reasonable cost and risk
- risk assessment: including cybersecurity, controllability, and unintended network impacts.

During a trial, progress is assessed against milestones defined at project initiation, with Steering Committees reviewing performance at each stage gate before deciding whether to proceed.

Where a project demonstrates sufficient evidence of net customer benefit, operational feasibility, and acceptable risk, the relevant Steering Committee makes a decision to commercially adopt. The innovation activity then transitions into business-as-usual delivery under the relevant operational team or programme, with ongoing performance monitoring. We are in the process of developing a formal benefits framework to assist with monitoring expected benefits to ensure they are continuing to be realised.

How we decide to discontinue

Not all innovation activity proceeds to adoption, and as Figure 9.3 shows, we treat discontinuation as a legitimate and expected outcome of a well-run innovation programme rather than a failure. Where trial evidence does not support adoption, because costs outweigh benefits, the solution does not perform as expected in our network conditions, or a better alternative exists, the relevant Steering Committee makes a formal stop decision and the learnings are documented and shared.

Information used to inform our innovation practices

We draw on a wide range of information sources to identify, scope, and evaluate innovation activity. These include:

- operational network and asset condition data
- smart meter and LV monitoring data
- customer research and engagement findings
- close-out reports from other EDBs' IPA and INTSA projects
- published research and case studies from international jurisdictions
- engagement with regulators, vendors, and sector forums including FlexForum and the ENA Future Network Forum.

We seek this information through structured trials and pilots, partner engagements including vendor and retailer arrangements where relevant, industry working groups, and direct customer engagement.

10

10. Network development approach

Our network development programme ensures our network can reliably meet changing customer needs. This section describes our network development approach, which follows a structured way of discovering plausible energy pathways, defining emerging constraints, and optioneering to determine the most prudent and efficient solution. Orion's connection processes are also outlined.

The approach described in this section provides a structured way to understand how we identify where investment is needed and how it is linked to three of our investment priorities:

- **Maintaining the network's safety and reliability levels**: we will ensure that existing customers and their reliability levels are not compromised while we continue to support the growing region, by using our Security of Supply Guide set out in Appendix F and asset ratings as limits.
- **Supporting strong population and demand growth**: increasing our ability to support growth by highlighting areas where demand is approaching firm capacity and where network reinforcement or reconfiguration is the most cost-effective solution.
- **Preparing for future energy needs**: our demand forecast incorporates emerging distributed energy resources (DER), electric vehicle (EV) charging, and assumed flexibility trends in our planning assumptions. This ensures our network is ready for future energy use.

10.1 Overview of our planning approach and context

Central Waitaha Canterbury continues to experience strong growth, particularly within the Selwyn District. Selwyn's resident population rose to approximately 78,000 in 2023 which is an increase of 29% over five years, far outpacing the New Zealand average national growth of 6.3% over the same period.

Even though process heat electrification, i.e. conversion from fossil fuels to electricity for industrial heating, has slowed, we are seeing strong and sustained growth in electricity demand from transport, commercial, and industrial sectors.

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

1. **Region A**: Christchurch city and outer suburbs, including Prebbleton. This represents approximately 6% of our physical network area and 83% of customers. This region is predominantly urban with higher customer density
2. **Region B**: Banks Peninsula, Selwyn district and townships. This represents approximately 94% of our physical network area and 17% of customers. This region serves lower-density rural areas, townships, and significant agricultural and processing loads.

Based on our current demand forecast, our network remains well placed to support future demand. At a subtransmission and zone substation level most of our network can meet future growth if we utilise and reinforce our 11 kV network to enable demand to be shifted between constrained and unconstrained zone substations.

We are continuing our approach of making the most of existing assets through building only when required and incorporating innovation and non-network solutions, e.g. hot water control and time-of-use tariffs, so that we avoid unnecessary cost to customers.

To guide how and where we invest, we have defined a clear set of network development objectives. These objectives translate our asset management objectives (covered in Section 6 – Asset management system) into practical network development focus areas that ensure we meet the evolving needs of customers as we continue to develop our network. The network development objectives and focus areas are listed in Table 10.1.

Table 10.1 Network development objectives and focus area

Asset management objectives	Network development objectives	Network development focus areas
Safety *Reducing the potential for network assets to cause harm to people to So Far As Reasonably Practicable (SFARP) levels*	Design and operate a safe network: ensure safety is embedded in network design, construction, operation, maintenance and decommissioning to protect staff, service delivery partners, and the public.	Safety in design: the selection and configuration of our assets for network expansion and upgrade will enable safe outcomes for staff, service delivery partners, and the public in all phases of the assets' life, including construction, operation, and decommissioning.
Reliable Network *Improve (in localised areas) or maintain reliability as measured by SAIDI and SAIFI*	Reliability to meet customer preferences: as we continue to connect new customers and support regional growth; we remain committed to delivering a network that meets customer reliability preferences at an affordable price	HV Security of Supply: to support a continuation of our current levels of reliability, the capacity and configuration of network expansion and infill upgrades will be designed in compliance with the HV Security of Supply Guide. Reliability management: network expansion and the configuration of network assets during renewal will ensure that reliability performance can be maintained at current levels with targeted improvements in localised areas, where supported by customer preferences.
Resilient Network *Strengthen the 4 Rs (Reduction, Readiness, Response and Recovery) to minimise impact on customers following a HILP event*	Design and manage a resilience network: we aim to embed resilience into the core of our network design by strengthening our ability to withstand and recover from major disruptions such as high-impact, low-probability (HILP) event. Where asset renewal opportunities allow, we invest in strategic interconnection, asset hardening, and contingency measures to enhance network resilience	Resilience in design: the selection and engineering installation design of our assets will harden our network to HILP events, creating a more resilient electricity supply. CBD resilience: during 66 kV asset renewal opportunities, complete the construction of a 66 kV meshed architecture in the CBD and surrounding area. Emergency spares: maintain a strategic stock of critical equipment, such as power transformers, key switchgear components, and other long-lead-time assets, to minimise restoration times during HILP events. This includes holding 'hot spares'[28] where appropriate to ensure rapid deployment when required.
Powering Today, Enabling Tomorrow *Support regional growth by maximising capacity through data and digital tools and enabling customer participation*	Ensure sufficient, scalable capacity to support growth and electrification: provide timely, efficient, and scalable network capacity to meet current and future demand	Targeted capacity reinforcement: prioritise capacity upgrades based on robust demand forecasting, economic/risk assessment, and emerging opportunities to ensure efficient and timely reinforcement where it is most needed. Customer-centric planning: engage early with large and emerging customers to co-design tailored network solutions that support electrification at the lowest cost. Data-driven decision making: leverage historical, real-time, and forecast network data, combined with network modelling and analytics, to inform investment decisions, optimise asset utilisation, and proactively manage emerging network needs.
	Enable customer participation: facilitate customer participation in the energy system by enabling safe, efficient connection of DER) and empowering customer generation and flexibility.	DER enablement: design and operate our network to safely accommodate increasing levels of DER, taking account of the role of price signals to manage our network impact of DER. This includes rolling out hosting capacity analysis tools and active DER management in constrained areas.

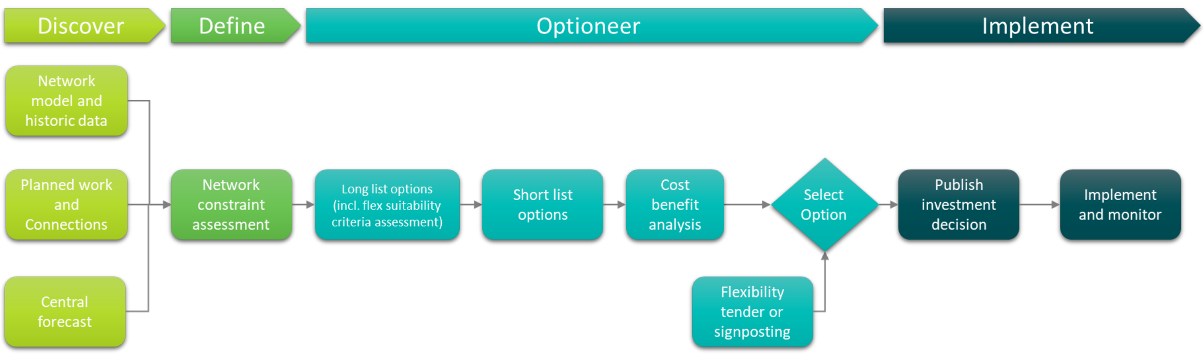
[28] Hot spares are power transformers that are installed, energised, and ready to take load.

Table 10.1 Network development objectives and focus area

Asset management objectives	Network development objectives	Network development focus areas
		Future-ready network design: build with possibilities and opportunities in mind while maintaining cost-effectiveness, e.g. future growth, evolving technology, and two-way power flows.
	Maximise the role of network non-wire solutions: leverage emerging technologies to support growth and decarbonisation objectives without relying solely on traditional network reinforcement.	New technology deployment: trial, evaluate, and embed suitable non-wire solutions through our Network Transformation programme. Where successful, these solutions will be considered as part of our business case development and optioneering processes, alongside traditional network investment options.
	Develop and integrate non-network solutions: advance our capability to deploy non-network solutions and demand flexibility as standard components of network planning	Non-network solutions deployment: trial, evaluate, and embed non-network solutions, such as demand flexibility and contracted curtailment, as viable alternatives to traditional network reinforcement. Solutions will be trialled and assessed through our Flexibility and Market Development programme, with learnings progressively incorporated into our standard investment decision processes.

To give effect to our network development objectives and focus areas in practice, we apply a consistent process to identify where investment is required. This process of **Discover, Define, and Optioneer** (Figure 10.1) is designed to support growth, preparing our network for future needs and making efficient use of existing assets and considering non-network solutions, where appropriate.

Figure 10.1 Network development investment process



In Sections 10.2 to 10.4, we describe how this process is applied in practice across zone substation/subtransmission, 11 kV network, and LV network. While the underlying decision framework is consistent, the specific thresholds and planning horizons vary by network level to reflect different risk profile. Table 10.2 summarises how each stage of the process is applied across the various network levels.

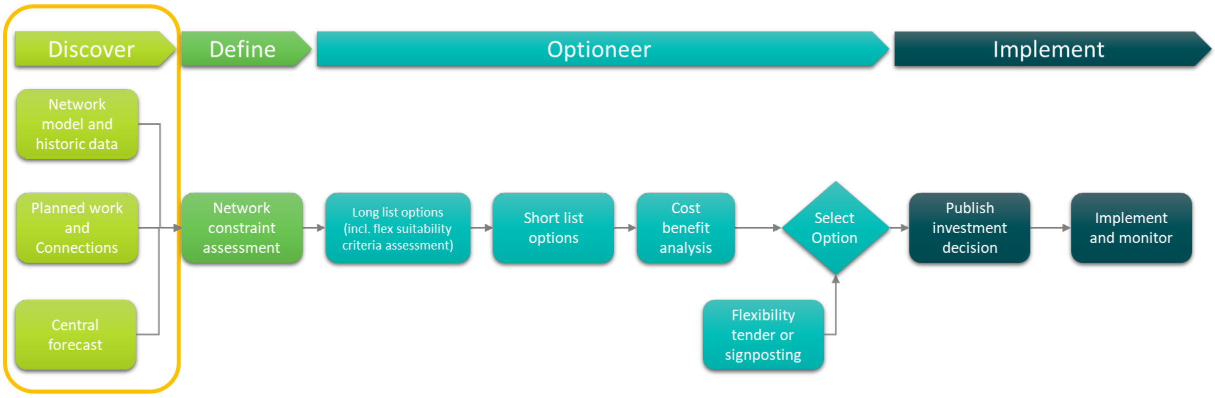
Table 10.2 Constraint identification process by network level

Network development process	Subtransmission / zone substations	11 kV network	400 V network
Discover	Central Forecast captures various emerging growth drivers and weather normalisation to provide a view of the demand required for the future		
Define	Compare forecast demand against capacity and HV Security of Supply Guide to identify current or future gaps. Estimate existing energy and load at risk, e.g., Value of Lost Load. Validate constraint using power-flow and contingency analysis, if required.	Use utilisation model to flag feeders >90% of nominal capacity and parallel rings >90% of their N-1 capacity. Validate flagged feeders using load-flow studies. Proceed to optioneering if constraint is a valid concern.	Develop an electrical model of the LV networks that incorporates demand forecasts, LV monitor and smart-meter data. Assess existing constraints utilising LV monitor and smart-meter data, then determine their severity by conducting power flow simulations across the networks over a ten-year timeframe. Quantify extent of LV constraint for feeders, distribution transformers using predefined constraint thresholds - 230±10% for voltage, 100% for conductors and cables, and 130% for transformers.
Optioneer	Optioneering will be undertaken for sites expected to reach constraints within the next 10 years. The long list and more detailed shortlist will be developed as part of the business case process, with the preferred option scoped and costed to ensure the solution remains fit for purpose for at least 20 years. The level of scope and costing accuracy is dependent on the expected project delivery timeframe.	Optioneering will be undertaken for sites expected to reach constraints within the next 10 years. The selected solution will be designed to remain adequate over a 10-year planning horizon.	

10.2 Discover: Understanding growth drivers

The first step in our network development process is to understand what is driving demand and where pressure on our network is likely to emerge. The **Discover** phase brings together three perspectives; the drivers we have observed historically, local development data that reflects what is happening today, and forward-looking demand forecasts based on multiple scenarios. These perspectives are shown as green boxes in Figure 10.2, on the following page. Together, they form a comprehensive view of how our network needs are expected to evolve over time.

Figure 10.2 Network development investment process – Discover



10.2.1 Network development demand drivers

The most common drivers of demand are:

- **Growth in the number of households and development**: driven by residential subdivisions, urban infill, and commercial development. These changes are often highly visible, with a strong correlation between consent activity and existing load growth. They typically affect the LV and 11 kV networks, and in some cases the zone substation level. Household numbers have increased uncertainty due to changing migration and policy changes, e.g. zoning and mass rapid transit schemes.
- **Increases in industrial load**: includes expansions in processing and other high-energy-use facilities. These are usually customer-specific and sensitive to broader economic or policy changes. The timing and magnitude are often uncertain.
- **Electrification of transport and process heat**: adoption of EVs and conversion from fossil fuels to electricity for industrial heating. These electrification trends are emerging and can be rapid but are customer-led and policy-dependent therefore timing is also uncertain. This driver could impact all voltage levels, with transport likely to first impact LV and process heat likely to first impact at the 11 kV and zone substation level.
- **DER and distributed generation uptake**: growth in rooftop solar, battery storage, and home energy management systems can influence demand and introduce new constraints that we have not experienced historically, particularly in the LV network, e.g. two-way power flow. As illustrated in Section 3.3.3, we are seeing steady growth in small-scale distributed generation uptake, alongside an increasing number of solar farm applications and commitments to construction, which are driving the need for enhanced subtransmission capacity.
- **Resilience and security of supply**: investments required to ensure continuity or timely restoration of supply during or after HILP events. These investments historically require physical redundancy and robust infrastructure solutions. This driver impacts the 11 kV, 33 kV, 66 kV, and zone substation levels.

Each of these drivers has the potential to introduce new constraints on our network, which will be assessed to ensure efficient and timely responses. The next step in our process involves identifying where and how these pressures could manifest as constraints across our network in the future.

In addition to these primary drivers, we also consider end-of-life assets as a key input when forming the need for a project. In some cases, ageing assets may present safety risks or affect service performance if not addressed. Depending on future growth patterns and network needs, these assets may be renewed on a like-for-like basis, upgraded, or removed entirely if they are no longer required.

10.2.2 Demand forecasting methodology

Our demand forecasting is based on the Central Forecast described in Section 3.5. The following sections set out the methodology used to develop it.

Through cross-functional workshops with subject matter experts, we reviewed the inputs, such as population growth, EV uptake and DER to reflect what we believe is most relevant for our regions. The agreed set of inputs, along with our strategic intent, forms our Central forecast, which we believe is the most appropriate path forward.

The Central Forecast is reviewed and signed off by our Integrated Leadership Team on a yearly basis. The approved Central Forecast is then used as a core input to growth-related investment planning, including zone substation upgrades, 11 kV and LV network reinforcement.

10.2.2.1 Overview of demand forecasting framework

Our demand forecasting framework consists of four key components:

1. **Baselines**: the starting points for the modelling (see Section 10.2.2.2)
2. **Drivers**: included in our driver-based forecast model (see Section 10.2.2.3)
3. **Location**: the granularity of our geographic and asset forecast model (see Section 10.2.2.4)
4. **Time**: the seasonality, day, and intra-day components of our forecast model (see Section 10.2.2.5).

The Central Forecast uses inputs (see Section 10.2.2.6) across the components described above to build a forecast with granular detail on drivers, geography, and timing.

For every location or asset modelled on our network, a location specific baseline load profile for a peak day is produced. For every driver shown in Table 10.3, a location specific forecast demand profile is produced for each year of the forecast. These are stacked to produce an overall demand profile.

The change in peak demand is the difference between the peak in the baseline forecast and the peak of the stacked driver forecasts for each year. The load profile also gives us detail on how the timing of demand for different technologies and load control can shift through the forecast years.

10.2.2.2 Baselines

Baselining is one of the most important parts of our forecasting process. We use baselines across most of the factors involved in forecasting. Those baselines identify the overall starting point for demand, which consists of the initial estimate, weather normalisation adjustments, residential and non-residential demand splits, and baseline estimates for our drivers.

10.2.2.3 Drivers and sub-models

We use driver-based forecasts for working out our future load. These forecasts use a set of assumptions and historical data to project growth and are used as an alternative to econometric regression-based forecasts due to the lack of data and uncertainty about future technology uptake and use, and to make best use of available smart meter data to give the most granular forecasts.

The five main drivers in the driver-based model are shown in Table 10.3, on the following page. Each of them is broken into sub-models to provide granular detail to the forecast.

Table 10.3 Main drivers and sub-models calculated for each driver

Drivers	Growth and urban development	Transport	Process Heat	Generation	Flexibility
Sub-models	Residential building	Light private vehicles	Process heat	Residential solar	Hot water
	Residential efficiency	Light commercial vehicles		Commercial solar	Orion load management
	Residential gas electrification	Goods vehicles		Utility solar	Retailer load management
	Industrial and commercial growth	Buses			Solar optimised
	Commercial gas electrification	Aircraft			Night controlled hot water
	Major connections				Residential battery energy storage system
					Commercial battery energy storage system
					Vehicle to grid

10.2.2.4 Location

We forecast demand at two separate aggregations. Demand is forecast directly at zone substation level. Each zone substation is modelled individually, and then together as an aggregated total. Demand is also forecast directly at a geographic area – Statistical Area 2 (SA2).[29] This is more granular than zone substation forecasts and is used for lower level 11 kV and LV assets on the network. Again, each SA2 is modelled individually, and then together as an aggregated total.

10.2.2.5 Time

The final key component of our forecasting is timing. The timing components of the demand forecasting model can be generalised as:

- **Annual changes**: each year of the forecast, the model produces a 25-year forecast
- **Seasonality**: different summer and winter components
- **Day to day**: components specific to different types of weather days
- **Intra-day**: the intra-day timing of demand.

Our demand forecasting model typically uses a combination of different types of peak day profiles experienced on the network across winter, summer, and specific holidays. Each of the 48 half hour periods per day are modelled, for a day at a time.

Each driver and sub-model that is added to the forecast has a 48-half hour profile, specific to the location, day, season, and year for the period being forecast.

[29] Statistical Area 2 (SA2) are medium-sized geographic units defined by Stats NZ to represent communities. They are large enough to provide robust statistical data but small enough to reflect meaningful local patterns, e.g. housing development and demographic change.

10.2.2.6 Forecast inputs

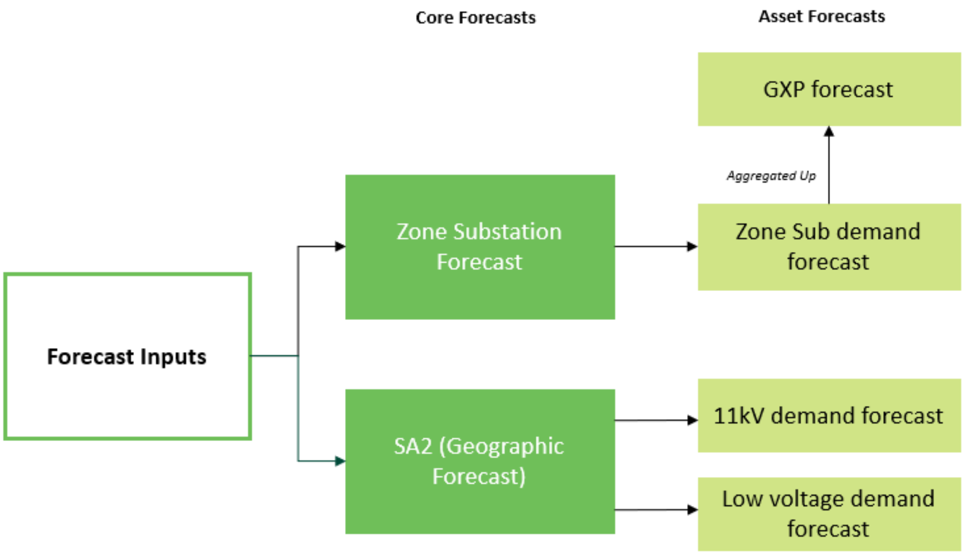
We draw on a range of inputs to build our Central Forecast which guides investment in the growth area. These inputs are tested through internal workshops and external engagement to ensure they remain relevant, robust, and traceable.

The forecast inputs generally fall into one of five categories:

1. **Historical data**: historical data as a baseline or input to modelling is generally sourced from the network or the relevant external provider, e.g. NIWA for historical weather data.
2. **National consistency**: assumptions for our regions are unlikely to be significantly different from national trends, so external references should be made, e.g. uptake of private EVs. We adopt external references, such as the Ministry of Business, Innovation and Employment's (MBIE) Electricity Demand and Generation Scenarios.
3. **Local adjustments**: national trends require adjustments due to local factors, e.g. population growth is faster in our regions than national trends.
4. **Bespoke local inputs**: where no national benchmark exists, e.g. for hot water load management, or local process heat electrification.
5. **Strategic intent**: where assumptions relevant to our strategic decision making are required, e.g. decisions on hot water load control programmes, investment in flexibility options, and our time-of-use pricing.

As shown in Figure 10.3, these inputs inform the Central Forecast to develop the core forecasts for zone substations and SA2 areas. These are then translated into asset-level forecasts for the 11 kV and low voltage networks, which are subsequently used for constraint analysis.

Figure 10.3 Generalised map of flow of forecast input to core forecasts and derived forecasts



10.2.3 Factors affecting Central Forecast accuracy

While the Central Forecast is developed using robust modelling, a range of external and internal factors can influence its accuracy. These factors include uncertainties in economic growth, population trends, technology adoption, and customer behaviour, as well as policy changes and weather variability. Recognising these factors is critical for effective asset management planning.

We mitigate these uncertainties through sensitivity analysis, as described below.

10.2.3.1 Population and economic growth

The largest factors in our demand forecast are population and economic growth, as they drive residential and commercial demand uptake. These factors are dependent on future expectations around the economy, migration and the relationship between economic growth and electricity demand growth.

For population growth we commissioned a study from demographic experts Geografia. They modelled the population and dwellings growth in our regions, between 2024 and 2055, that our demand forecast relies upon. We commissioned this study to provide an independent projection which gives us greater confidence in our forecasts, as well as a probabilistic output that can be used in scenario and sensitivity analysis.

Economic growth is the combination of population growth and per capita economic growth projected by The Treasury New Zealand.

10.2.3.2 Electrification

The rate and impact of electrification of heating, transportation, and industrial processes is highly uncertain. We base our assumptions in the Central Forecast on national benchmarks, where these are available.

10.2.3.3 Weather and climate

As described in Section 10.2, we use an econometric modelling approach to model uncertainty related to weather in our demand forecasting. We estimate a 50% and 90% probability of exceedance based on weather variability through the year. The model also functions to estimate the impact of climate-related change based on NIWA climate projections, but we have found minimal expected impact on peak demand within the forecast period.

10.2.3.4 Customer-initiated projects

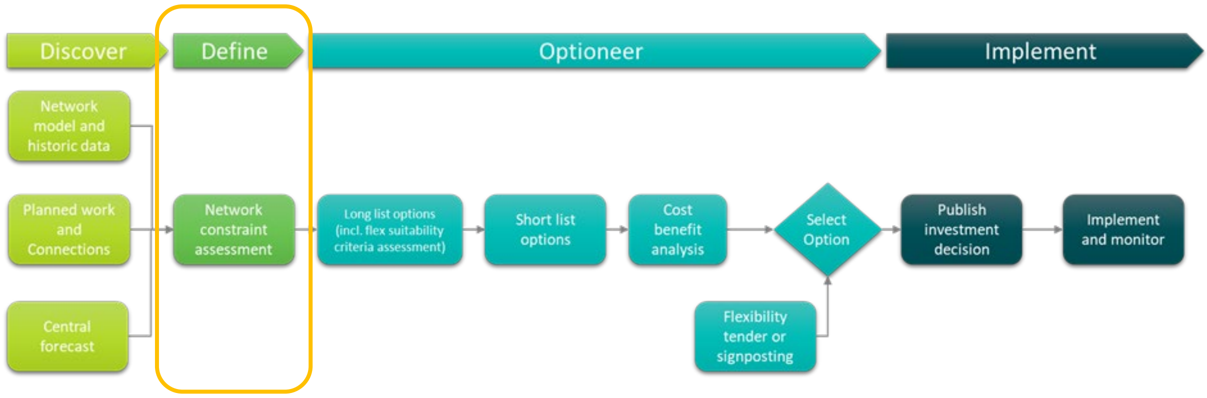
Process heat conversions are included in the Central Forecast, phased over a five-year period based on direct customer engagement and the assessed probability of conversion timing.

Other uncertain but substantial customer-initiated projects, such as large industrial connections, data centre development, and new greenfield developments, are also assessed for scope clarity, probability and timing. If sufficiently uncertain, they are excluded from the Central Forecast and listed as ‘nascent’ – refer to section 12.2.3.

10.3 Define: Assessing network constraints

Building on our understanding of growth drivers, we monitor and analyse our network to identity emerging and forecast constraints that may affect reliability, capacity, or resilience. In the **Define** stage, as shown in Figure 10.4, we apply our planning standards, reliability benefit metrics, and asset ratings to identify and define network constraints. These constraints serve as the initial trigger for further investigation. Once identified, they are evaluated through detailed analysis during the **Optioneer** stage, where potential investment and non-network solutions are explored, compared, and prioritised based on risk, cost, and customer benefits.

Figure 10.4 Network development investment process – Define



10.3.1 Network planning criteria and security standards

As part of our network constraint assessment, we use our HV Security of Supply Guideline to inform the appropriate level of supply security for various parts of our network, considering factors such as customer type and location, peak demand, applicable contingencies, and the ability to restore supply following an outage.

The guideline serves as a benchmark for assessing the normal operating and contingent network capability to identify gaps, both existing and forecast, based on forecast load growth and network configuration. The guideline does not mandate network reinforcement if our network does not meet the prescribed level of security; instead, it triggers an optioneering process for the development and reinforcement of our subtransmission and 11 kV distribution networks, which includes a detailed economic and risk assessment to evaluate potential solutions.

The guideline supports a tiered approach to investment decision-making:

- **High-risk non-compliance**: where a security gap poses significant resilience or reputational risk, such as extended outage potential in critical areas, and it is above our risk appetite, it is reported to our Audit Risk Committee with mitigation expectations and tracking as defined in our Risk Guideline.
- **Low-risk non-compliance**: where the security gap has limited risk, customer or economic impact then it becomes an optimisation exercise, typically addressed through lower-cost, lower-impact solutions or operational adjustments.

10.3.2 Constraint identification process

The purpose of the constraint identification process is to provide a clear and structured view of existing and emerging network constraints that could inhibit our ability to deliver reliable and future-ready services. Constraints may relate to thermal overloads, voltage or power-quality breaches, or security of supply (N-1) risks.

Constraint identification applies to the subtransmission (including zone substations), 11 kV and LV networks, considering current operating performance and forecast growth over a 10 to 20 year planning horizon. We recognise that constraint identification is not a one-off exercise, but a continual process. As data, operational insights, customer behaviours, and our network evolve, our maturity to assess constraints also needs to evolve.

The output of the constraint identification process is described in Section 11 – Network demand, distributed generation, and constraint forecasts and *Appendix B.5 – Schedule 12b – report on forecast capacity*.

10.3.3 Integrating asset lifecycle and network planning decisions

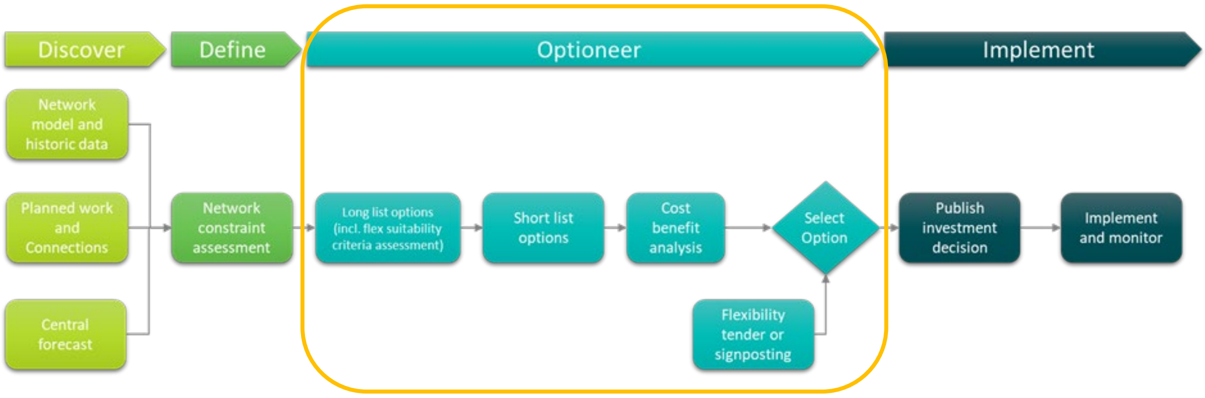
In addition to identifying constraints, our decision-making process integrates asset lifecycle considerations to determine when assets should be replaced, refurbished, or retired. Where a network constraint is identified, we assess the criticality and remaining life of affected assets to determine whether renewal activities can be optimally coordinated with network reinforcement or reconfiguration solutions.

Conversely, when assets approach end of life in zone substations or reinforcement projects, they are assessed through the same structured business case development and optioneering process. This ensures that decisions consider future demand forecasts and the most efficient use of existing network capacity. In some cases, this results in asset rationalisation rather than replacement, such as decommissioning underutilised distribution substations and resupplying load from adjacent parts of the network. Through this integrated approach, we ensure that replacement and refurbishment decisions are not made in isolation, but are aligned with broader network needs. Our renewals forecasts reflect this integrated approach, to the extent that it is possible to do so in advance of detailed project planning

10.4 Optioneer: Evaluating solution pathways

Once a network constraint has been identified and defined, we move into the **Optioneer** stage to determine the most effective solution. To support transparent decision-making, we follow a structured process, set out in Figure 10.5, when considering various potential solutions as possible alternatives to network reinforcement or expansion.

Figure 10.5 Network development investment process - Optioneer



Optioneering is undertaken through a structured long-list and short-list process. A broad range of potential solutions is first identified, with the most credible options then progressed through cost-benefit analysis to identify the option that delivers the greatest net benefit to customers. This process is supported by cross-functional working groups, with input from our Network Development, Engineering Support, Network Portfolio, and Flexibility and Market Development teams, to ensure that all viable options have been considered and that investment proposals are robust, well-tested, and assessed from multiple perspectives.

The key components of the optioneering process are outlined below:

- **Long-list options**: we start by identifying the full range of plausible network and non-network options that could address the identified constraint. These options are then subject to a high-level screening to assess feasibility, considering the type of constraint, timing, expected growth rates, and the duration required for any non-network solution.
- **Short-list options**: long-list options are screened against safety, risk, fit for purpose, technical, delivery, and cost criteria to create a short-list. The ''Do nothing'' option and three to four of the most credible options are then progressed onto the next step. If a non-network solution is deemed a viable candidate, we signal the opportunity to the market through our flexibility opportunities viewer.
- **Cost-benefit analysis**: short-listed options are assessed based on economic analysis, comparing net benefits taking account of cost, avoided costs, and reliability performance. Sensitivity analysis is undertaken to test the relative value of deferral and reliability assumptions/forecasts etc.

Constraints can be solved using a mixture of network build solutions, network augmentation to increase the utilisation of the existing network, and non-network solutions to make use of third-party technology/support. For example, the non-network solution of demand-side flexibility can often be an economic solution to defer traditional network upgrades due to load growth, but if the load growth is too large, a traditional solution may also be required.

As our network continues to evolve, particularly with increasing uptake of distributed generation and export-capable DER, we recognise the importance of continually strengthening our optioneering process to ensure that investment decisions appropriately balance cost, risks, and customer outcomes.

Growth forecasts can sometimes be uncertain as they often require significant investments from businesses and households to materialise. The utilisation of short-term opex solutions can provide the network with the required capacity while allowing time for load growth to materialise, thereby reducing the likelihood of overinvestment in network capex solutions.

The following sections describes each of the potential solutions in detail.

10.4.1 Do nothing

There is an option to accept the existing level of service and take no immediate action when informed by economic assessment, residual risk evaluation, and customer impact. This option is always considered to ensure investment is only undertaken where the benefits of intervention outweigh the costs of not acting.

10.4.2 Network augmentation

Network augmentation is where load is shifted from constrained assets to an underutilised asset that is geographically close to the constraint. Examples are shifting open points, minor feeder reconfiguration, or revised asset ratings following an asset capability assessment, e.g. we might choose to run power transformers higher than 100% of their capacity.

Network augmentation is often the lowest cost way to resolve constraints on our network and often require a shorter lead time to implement, meaning constraint solutions can be planned and solved in the same year as the constraint occurs, reducing forecasting risk and potential overinvestment.

10.4.3 Network build

This solution considers more substantial traditional build options. This is not limited to a single solution, as all options should be considered. Examples include:

- building bigger for increased thermal or voltage performance capacity
- building new to remediate high utilisation of existing assets
- building new to provide additional security of supply.

Network build solutions provide enduring capacity and reliability benefits that cannot always be achieved through augmentation or other alternatives. Even though network build solutions typically involve higher upfront capital investment, they are selected where economic analysis demonstrate that the long-term benefits to customers outweigh the cost of deferral or alternative options.

10.4.4 Network non-wire alternatives

Non-wire alternatives include solutions that solve network issues without poles, wires, or transformers, but still require electrical infrastructure to be built. Some examples are:

- connecting generation to our network to reduce peak demand capacity constraints
- energy/electricity storage to create or maintain N-1 security
- removing uneconomic network connections and creating a microgrid to supply customers.

Even though non-wire alternatives still require targeted investment in infrastructure, they can unlock broader value beyond traditional network benefits, i.e. their potential to enhance resilience and customer outcomes. For example, in a remote community where network redundancy is limited, installing a solar and battery system as a microgrid can provide local backup supply during outages. This setup reduces reliance on long feeders that are costly to upgrade or repair, while also improving community resilience during HILP events.

10.4.5 Security level breach

We set security level requirements for different parts of our network, as outlined in our HV Security of Supply Guide. When growth and an associated network constraint are forecast to exceed our security of supply criteria, we will undertake a risk assessment and economic analysis to determine whether the security of supply breach can be cost effectively resolved. We also consider whether reliability in the area is meeting customer expectations.

In some cases, the most appropriate solution is to accept the security of supply breach until further growth or other factors in the area support a remediation investment. Enabling security level breaches ensures that the value of the security is considered, e.g. is the economic reliability benefit greater than the cost of building the second transformer. If not, then deferring the project, reducing overinvestment, and optimising the capacity of our existing assets, is considered the preferred solution.

10.4.6 Non-network solutions

Non-network solutions[30] are an increasingly important part of our approach to manage emerging constraints and defer or avoid traditional network investment on both the 11kV and low voltage networks. Section 9 – Transforming our network outlines our plans to further develop our non-network solution capability. Similar to other EDBs, we consider a range of flexibility enablement modes, each offering different levels of firmness, cost, and controllability.

The market for non-network solutions remains nascent. We are actively working to develop this market, particularly contracted flexibility services. Where we already operate non-network solutions, such as

[30] Examples of non-network solutions are contracting third parties to manage a network constraint via a demand side response and/or battery storage, or our existing hot water control via ripple injection plants.

ripple hot water load control, we will continue to use these where economic assessment indicates they remain the best option for managing network constraints.

While a competitive market for non-network solutions develops, and to ensure customers are not exposed to a higher cost than would be incurred through a traditional network solution, we determine the annualised cost of the equivalent network investment as a ceiling on what we are prepared to pay for contracted non-network solutions. This approach protects customers while maintaining genuine incentive for the non-network solutions market to develop.

We need to give the market of flexibility service providers sufficient lead time to respond to our need for flexibility services. We work backwards from the required decision point to allow flexibility service providers adequate time to assess opportunities, submit proposals, and deploy capability. This enables us to make an informed assessment of whether flexibility is likely to materialise at an acceptable cost and level of firmness.

To support early engagement, we publish high-level information on areas we believe may become constrained, through our public flexibility opportunities page, available on our website.[31]

Where the market does not respond, or where flexibility proposals do not demonstrate deliverability or value for customers, we will revert to the next preferred option to ensure that network investment decisions continue to appropriately balance cost, risk, and benefits including customer service levels.

10.5 New connection processes

Our connection processes have evolved significantly in recent years, adapting to technological change, increasing complexity, and rising customer expectations. The frameworks and processes described in this section position us to continue meeting these challenges while maintaining efficient, safe, and timely connection services.

10.5.1 Connection framework and classification

Our connection framework classifies customer connections into distinct categories based on complexity and scale. This enables us to provide appropriate service levels and pricing structures tailored to each connection type.

Standard residential and small business connections typically involve straightforward requirements and are processed through streamlined procedures using predetermined technical solutions and standardised pricing. We classify these connections as urban or rural based on territorial authority definitions and include:

- new residential dwellings
- small commercial premises
- minor infrastructure connections, such as telecommunications cabinets and water pumps.

Larger commercial and industrial connections require more detailed assessment due to their potential impact on network capacity and power quality. Our connection and network planning teams work closely with these customers to understand their specific requirements, including any special reliability needs, power quality constraints, or operational characteristics. These connections often require bespoke design solutions and comprehensive load assessments.

Property development connections involve multiple new connections and often require network extensions or reinforcement. We engage early with developers for these projects to understand staging requirements, ultimate development capacity, and infrastructure ownership arrangements. We distinguish between multi-unit infill and larger greenfield developments.

[31] See: https://www.oriongroup.co.nz/your-energy-future/flexibility-opportunities-viewer

Distributed generation connections form an increasingly important category. These range from small residential solar generation installations to larger utility-scale generation systems. The connection requirements vary significantly based on system size, type, and potential network impacts.

We encourage pre-application meetings for significant projects. These meetings enable:

- early identification of potential issues or constraints
- alignment of expectations regarding technical requirements and timeframes
- preliminary assessment of network capacity availability
- discussion of potential alternative solutions or staged approaches
- coordination with other planned developments or network works.

Pre-application engagement can significantly streamline the formal application process and reduce overall project timeframes by resolving potential issues early.

10.5.2 Application and assessment process

We have significantly modernised our connection application process through the implementation of a Customer Relationship Management platform. This platform has improved both customer experience and internal efficiency by providing:

- online application submission and tracking
- automated workflow management
- improved data capture and record-keeping
- enhanced communication with applicants throughout the process.

Once we have received a connection application, our initial assessment considers several key factors:

- **Technical feasibility**: this encompasses an evaluation of available network capacity at the proposed connection point, assessment of voltage levels and power quality parameters, and identification of any network reinforcement requirements. Our network planning teams use sophisticated modelling tools to assess the cumulative impact of new connections on network performance and to identify any constraints that may affect the connection.
- **Safety and compliance**: we prioritise safety and compliance requirements in our assessment process. We verify that the proposed installations meet all relevant technical standards, including our Network Connection Standard, and that appropriate safety clearances and access arrangements are in place. For distributed generation connections, we assess compliance with relevant power quality standards and protection requirements.
- **Connection costs**: commercial arrangements are determined based on our Connections and Extensions Methodology, which sets out the capital contribution framework and commercial terms. The methodology ensures that connection costs are allocated fairly between connecting customers and our broader customer base, following regulatory guidelines based on principles of cost-reflectivity and economic efficiency.

10.5.3 Connection offers and capital contributions

Our connection offer framework provides transparency and certainty for connecting customers, while ensuring fair cost allocation between new and existing customers. Our approach differs based on connection type and complexity. While the full connection pricing methodology provided on our website should be followed for detailed application, the key points are summarised below.

Standard residential and small business connections with low complexity (e.g. single or three phase urban, or three-phase rural) are charged a fixed amount. These published amounts provide customers with early transparency of the cost they will face. The published amounts are set at efficient levels that balance the up-front contribution from the customer with ongoing revenue we expect to receive from the customer once the connection is livened.

Non-standard offers for larger and more complex connections are determined on a case-by-case basis and may include:

- technical specifications and requirements
- any special conditions or operating restrictions
- itemised cost breakdown
- capital contribution requirements
- estimated timeframes for design, construction, and energisation.

For these connections, we undertake a standardised calculation to determine the amount of contribution the customer must pay. Our calculation is based on an 'incremental cost less incremental revenue' approach in line with regulatory guidance. This ensures connecting customers contribute appropriately based on their specific circumstances, while existing customers do not subsidise new connections.

Utility scale distributed generation connections include specific technical requirements relating to protection coordination, voltage management, and any operational constraints necessary to maintain network security and power quality.

Connection agreements formalise these commercial and technical arrangements between Orion and the connecting party, specifying connection capacity and configuration, capital contribution amounts and payment terms, technical and safety standards to be met, ongoing operational requirements, and respective responsibilities for asset ownership and maintenance.

10.5.4 Altering existing connections

10.5.4.1 Capacity upgrades

Existing customers seeking to increase their connection capacity must undergo an assessment process that evaluates the customer's historical maximum demand, the incremental capacity sought, and the cumulative impact on local network infrastructure.

For minor capacity increases within the existing connection assets' capability, the process may be relatively straightforward, involving updated protection settings and potentially upgraded metering. However, significant capacity increases often trigger the need for upgraded service lines, transformers, or upstream network reinforcement.

We anticipate increasing demand for capacity upgrades driven by electrification initiatives, particularly:

- installation of EV charging infrastructure
- process heat electrification in commercial and industrial settings
- installation of distributed generation and battery energy storage systems.

Our planning processes incorporate forward-looking assessments to anticipate these trends and ensure network capacity is available when needed, minimising delays for customers seeking to electrify.

10.5.4.2 Distributed energy resource connections

The connection of DER, including solar panels, wind turbines, battery energy storage systems, and vehicle-to-grid capable EVs, requires specific approval processes to ensure safe integration with our network.

Small-scale systems, typically residential installations, follow a streamlined approval process. We maintain approved inverter lists that meet our technical standards, enabling faster processing for compliant equipment. Customers, or their electrician, can find information about our policies and approach to DER connections on our website (Generation | The Orion Group) and submit applications through our online portal (Orion - Online services). Approvals are generally provided quickly for standard installations.

Larger distributed generation systems require more comprehensive assessment, including:

- detailed network studies to evaluate network impacts, including voltage rise and thermal constraints
- fault level contribution analysis
- protection coordination requirements
- assessment of power quality impacts such as harmonics and flicker
- coordination and impact studies with Transpower (as grid owner and system operator)
- evaluation of operational constraints under different network conditions.

The integration of battery energy storage systems presents particular challenges and opportunities. These systems can provide network support services through peak demand management and voltage support, but require careful consideration of:

- operating modes and control system integration
- safety requirements and protection coordination
- export limitations and ramping constraints
- communication and monitoring requirements.

We will continue to develop specific technical standards, and connection and pricing agreements, for these emerging technologies, informed by our participation in industry forums and pilot projects.

10.5.4.3 Alterations and temporary connections

Alterations to existing connections or temporary connections may be required for construction activities, special events, or emergency situations. Our processes distinguish between:

- **Alteration to an existing connection**: where an existing connection point needs to be altered to support customer needs. These alterations have specific safety requirements and are managed through our standard connections processes, with costs being the responsibility of the applicant.
- **Temporary connections**: which provide power supplies for special events, building sites, and construction activities. These connections have specific safety requirements and are managed through our standard connections processes, with costs being the responsibility of the applicant.
- **Emergency alterations**: which may require rapid response to maintain supply or address safety concerns. We have established expedited processes that maintain safety and technical standards while enabling timely resolution of urgent customer needs.

10.5.5 Minimising connection costs

10.5.5.1 Cost-effective design principles

Our approach to minimising connection costs focuses on optimising design solutions, while maintaining appropriate safety and reliability standards. We employ several strategies:

- **Standardised designs**: these are used wherever possible, reducing engineering costs and enabling economies of scale in equipment procurement. Our design standards library covers common connection scenarios and provides proven solutions that meet our technical requirements.
- **Whole-of-life cost optimisation**: this guides our selection of connection configurations. We evaluate energy losses, maintenance requirements, and future upgrade potential rather than simply minimising initial capital costs. For example, while overhead connections may have lower

initial costs, underground solutions may be more cost-effective when considering reliability, maintenance, and amenity factors.

- **Alternative technology solutions**: these are actively explored to reduce connection costs. This includes use of covered conductor technology for rural connections, modern compact switchgear to reduce substation footprints, and smart connection solutions that optimise network utilisation.

10.5.5.2 Customer choice in connection works

Customers have choice over who undertakes their connection and livening works. This approach enables customers to:

- obtain competitive quotes for connection works
- choose contractors based on price, timing, and other factors
- integrate connection works with other construction activities
- manage project timing to suit their requirements.

10.5.5.3 Non-traditional solutions

We are actively exploring alternative service options that may reduce connection costs while meeting customer needs, such as:

- **Flexible connection arrangements**: allow customers to connect distributed generation or significant loads with acceptance of operational constraints rather than requiring immediate network reinforcement. These arrangements can significantly reduce connection costs and timeframes, while maintaining network security through agreed curtailment protocols under defined conditions.
- **Load management solutions**: enable customers to agree to controllable load arrangements in exchange for reduced network charges. This is particularly relevant for EV charging infrastructure, where charging can often be shifted to off-peak periods without impacting customer utility, reducing the network capacity required for the connection.
- **Embedded network arrangements**: for large developments, these enable the developer to own and operate the internal reticulation, connecting to our network at a single point. This can reduce costs by enabling the developer to optimise the internal network design for their specific needs.
- **Non-wire alternatives**: such as standalone power systems or microgrids may be more cost-effective than traditional network connections for very remote locations. We work with customers to evaluate these options where they may provide better overall outcomes.

10.5.6 Connection timeframes and communication

10.5.6.1 Connection timeframes

The time required to approve a new connection varies depending on connection type and complexity. Table 10.4 below sets out indicative timeframes for the approval stage of the connection process for different connection categories, drawing on our recent performance data.

Table 10.4 Approval time for connection type

Connection type	Average time to approval (based on performance from 1 April to 31 Dec 2025)
Brownfield developments (generally where electricity network infrastructure already exists)	29 working days
Greenfield developments (generally areas of development previously unreticulated)	8 working days
Temporary connections	5 working days

Table 10.4 Approval time for connection type	
Connection type	**Average time to approval (based on performance from 1 April to 31 Dec 2025)**
Large connections >100A	62 working days
Distributed generation <15kW	10 working days

Once an application has been reviewed and approved, a quote is returned to the customer for the customer to accept or decline. The time taken by the customer to accept or negotiate the offer is outside our control and is not included in the approval timeframes above. Complex or high-value connections can involve extended commercial negotiations.

A request by the customer to connect and liven an approved connection, results in an ICP being created on the registry and approval being sent to the customers retailer within 3 working days, in accordance with the requirements of the Electricity Industry Participation Code 2010. Once the retailer claims the ICP, within 3 working days Orion issues a request for connection and livening. Livening of the new connection then occurs, assuming network upgrades are not required, and this is typically completed within 10 working days.

While we aim to process applications as efficiently as possible, several factors can extend connection timeframes beyond the typical ranges above:

- **Network capacity constraints**: where the proposed connection point has limited available capacity, additional network reinforcement or upgrade works may be required before the connection can proceed. The planning, consenting, and construction of such works can add weeks or months to overall timeframes. Information on areas of the network where constraints are more likely to be encountered is available through our network capacity publications (refer section 10.5.7).
- **Third-party dependencies**: connections that require coordination with Transpower, territorial authorities, or other utilities (for example, road opening consents, or works in close proximity to other infrastructure) are subject to third-party timeframes outside our control.
- **Site access and customer works**: the connection process cannot be completed until the customer's on-site installation is ready for inspection and connection. Delays in customer-side works, or difficulties obtaining access to the site, will delay the overall connection timeline.
- **Consent and permitting requirements**: some connections, particularly those requiring new overhead or underground network extensions through public or third-party land, may require resource consents or other statutory approvals. Consenting timeframes are subject to statutory processes and are outside our direct control.

We communicate expected timeframes to applicants at the outset of the application process and provide updates through our online portal and direct contact from our connections team if delays are anticipated.

10.5.6.2 Communication

Effective communication throughout the connection process is essential for customer satisfaction and project success. We have implemented a multi-channel communication approach that provides customers with choice in how they interact with us, while ensuring consistent information across all channels.

Our online portal provides 24/7 access to:

- application submission and tracking
- document upload and management
- project status updates and milestone notifications

- access to technical standards and guidelines
- payment facilities for connection charges.

Communication and notifications are sent to connection applicants at key milestones, including application receipt, assessment completion, offer issuance, and connection energisation. These communications include clear explanations of what has been completed and anticipates the next steps.

For complex projects, we assign dedicated project managers who serve as single points of contact. These project managers coordinate internal resources, manage stakeholder communications, and ensure projects progress efficiently through each stage.

10.5.7 Information sharing about network capacity

10.5.7.1 Network capacity information

Transparently sharing information regarding network capacity and constraints enables more efficient connection planning and investment decisions by developers, consultants, and major customers. We provide network capacity information through multiple channels with different levels of detail appropriate to various stakeholder needs:

- **AMP capacity indicators**: we provide information on network capacity at both GXPs and zone substations in this AMP. This information helps inform initial site selection and feasibility assessments for developments
- **Detailed capacity information**: Customers seeking detailed capacity information can submit a capacity application request, which provides an opportunity to have a more substantive conversation with us about their specific needs. We have developed a publicly available capacity map covering the 11 kV network and above, which is available on our website.[32] At the LV level, identifying constraints relies primarily on smart meter network operations data. As our LV visibility matures, we will evaluate options for making identified LV constraint information more readily accessible to customers and developers.
- **Project-specific assessments**: are provided as part of the connection application process, giving applicants detailed information on capacity availability and any constraints affecting their specific connection.

10.5.7.2 Digital platform development

Our digital transformation includes ongoing investment in platforms that enhance information sharing and customer engagement. The recent implementation of our Customer Relationship Management platform provides the foundation for more sophisticated customer self-service capabilities.

We are developing capabilities for:

- self-service capacity assessments for standard connections
- automated approval of standard connection and distributed generation applications, where appropriate
- real-time visibility of application processing status
- integration with other business systems to provide a more seamless customer experience.

[32] See: https://www.oriongroup.co.nz/your-energy-future/hosting-capacity-viewer

10.5.7.3 Future direction

The connection landscape continues to evolve rapidly, driven by decarbonisation initiatives, technological advancement, and changing customer expectations. Our connection processes must continue to adapt to these changes, while maintaining our objectives of safety, reliability, and affordability.

Key areas we are focused on include:

- **Process digitalisation and automation**: to reduce processing times and improve customer experience. This includes development of automated design tools for standard connections and enhanced assessment capabilities for complex connections
- **Flexible connection frameworks**: that enable faster connection of DER by accepting operational constraints rather than requiring immediate network reinforcement. These arrangements could significantly reduce connection costs and timeframes for renewable generation and battery energy storage systems while maintaining network security
- **Predictive capacity management**: using advanced analytics to anticipate connection needs and proactively develop network capacity. This approach moves beyond reactive reinforcement to strategic capacity development that efficiently enables future connections
- **Enhanced stakeholder collaboration**: to coordinate network planning with regional development plans, ensuring infrastructure is developed efficiently to support community growth and the energy transition.

11

11. Network demand, distributed generation, and constraint forecasts

This section sets out our forecasts for network demand, and capacity requirements across our network, including Transpower's grid exit points (GXPs), and our zone substations and distribution network utilisation.

These forecasts are based on our forecasting methodology, planning criteria, demand drivers, and our approach to network development described in Section 10. The specific projects and programmes we are implementing in response to the forecast constraints and security gaps identified in this section are set out in Section 12 – Network development programme.

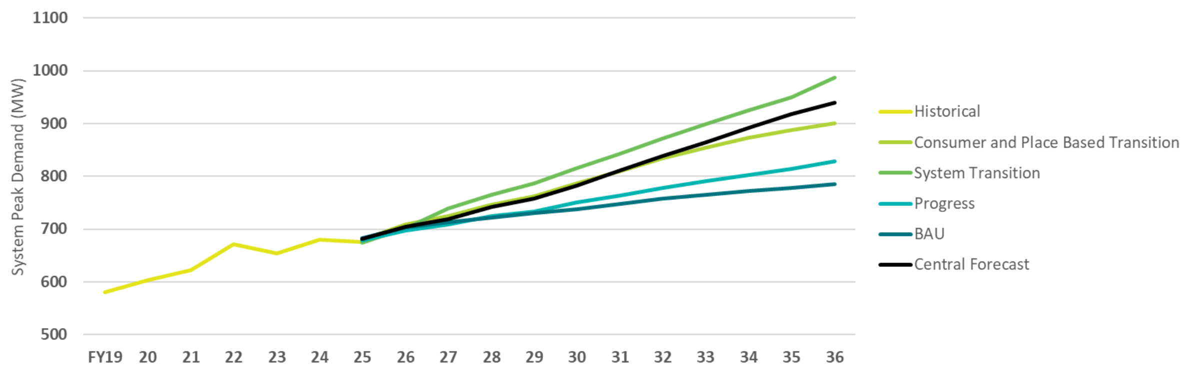
Central Waitaha Canterbury is one of New Zealand's fastest-growing regions, as outlined in Section 3. As New Zealand decarbonises, electricity will play an even bigger role in transport, heating, and everyday uses, further accelerating future demand on our network.

This section shows where this demand growth will challenge our network capacity over the next 10 years. Section 11.2 shows our forecast demand and forecast distributed generation and new customer connections. Where forecast demand exceeds network capacity, or breaches our HV Security of Supply Guide, Section 11.3 identifies where these issues currently exist or are forecast to occur during the AMP period.

11.1 Peak demand forecast

Our network development investment planning is based on the Central Forecast described in Section 3.5 and Section 10.2. Figure 11.1 shows how our Central Forecast compares to the full range of our Future Energy Scenarios, illustrating both our planning basis and the uncertainty we are planning against.

Figure 11.1 Network peak demand – Future Energy Scenarios and Central Forecast comparison

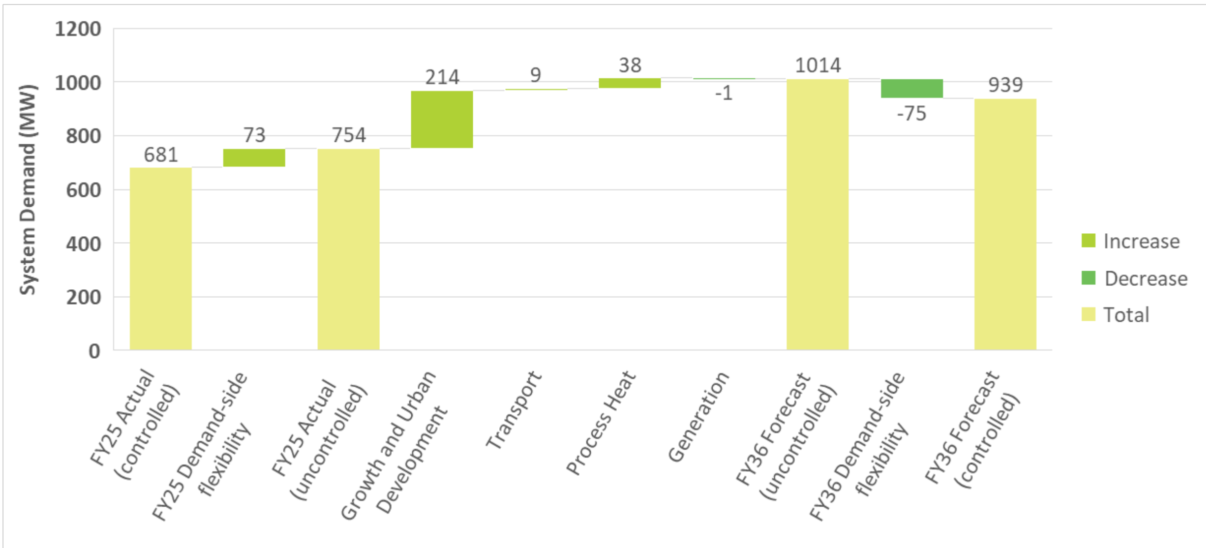


Under the Central Forecast, we expect approximately 31% growth in total network peak demand between FY27 and FY36, an increase of around 221 MW. We expect the peak to occur in winter, with growth driven by population increases. This in turn, drives residential expansion and infill, as well as greater commercial and industrial growth.

Transport electrification becomes a significant factor in later years, though its impact may be seen earlier in some areas across our network with higher electric vehicle (EV) uptake. Process heat conversions will contribute further growth in later years as well.

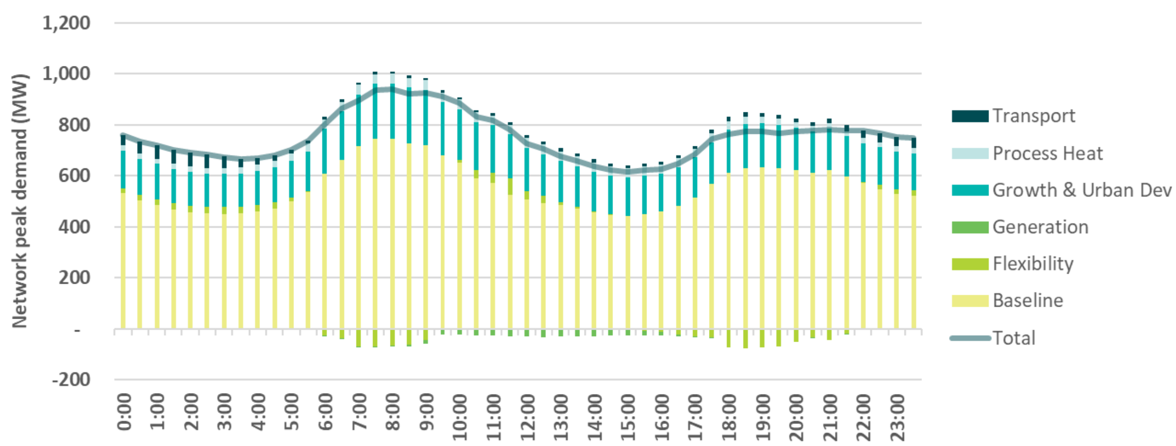
The major growth factors that contribute increases in demand, and in some cases, decreases to the anticipated peak network demand over the AMP period, are shown in Figure 11.2.

Figure 11.2 Central Forecast load growth by factor – FY25[33] to FY36



In FY36 we expect to see similar demand patterns on peak days to FY25. Peak days on our network are typically cold winter mornings, where the combination of commercial demand and morning household demand causes peaks, which are flattened by hot water load control and major customer pricing responses. Residential areas of our network typically peak during winter evenings and are also mitigated by hot water load control. Figure 11.3 shows the FY36 peak day demand profile.

Figure 11.3 **Peak demand profile by factor – FY36 Central forecast**



In our Central Forecast, we have assumed that evening peak EV charging demand can be shifted to overnight periods. Our time-of-use pricing is likely to incentivise this shift; however, it is likely there will need to be further incentives from retailers and education for EV owners. More EV charging during the evening peak period could add significantly to the transport sector's contribution to peak demand in residential areas.

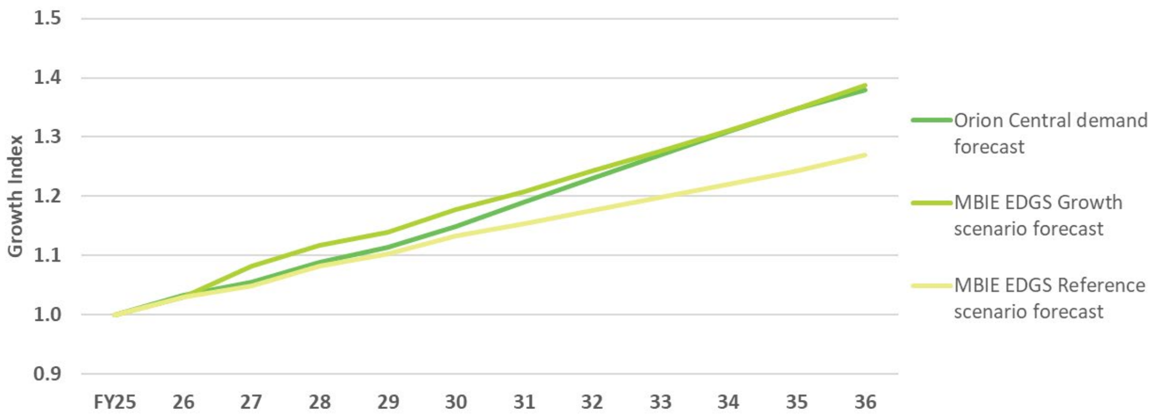
We benchmark our results against the Ministry of Business, Innovation and Employment’s (MBIE) Electricity Demand and Generation Scenarios to check for consistency with other national forecasts, as shown in Figure 11.4.

Our Central Forecast rises faster than MBIE’s Reference scenario and is consistent with MBIE’s Growth scenario by FY36. The main difference between MBIE’s and Orion’s forecasts is the forecast population and economic growth. As the population growth in our regions is faster than the national average, both

[33] FY25 is our forecast baseline, which includes weather normalisation adjustments. It is not the value of maximum coincident system demand, 678MW, as reported in Schedule 9e(ii).

historically and forecast, we see MBIE's Growth scenario as the more appropriate comparator for our forecast growth.

Figure 11.4 Orion's peak demand growth forecast, compared to forecasts under MBIE's Growth and Reference scenarios



11.2 Network loading and forecast

This section sets out our demand forecasts under the Central Forecast for Transpower's GXPs, and our zone substations, 11 kV feeders, and LV networks.

For GXPs and zone substations, we show present and expected maximum demands over the next five years as year-on-year projections (FY27 to FY31), along with 5-year and 10-year forecast modelling output ranges. The 5-year and 10-year ranges reflect the Central Forecast and high demand forecasts.

The demand forecasts represent unmitigated demand, which is the demand expected if no network reinforcement work, such as zone substation capacity upgrades, new substations, or load transfers, is undertaken. They do not include the potential impact of new demand response or DER management that may be procured as part of non-network solutions that address specific network constraints. This approach demonstrates where network investment is required to maintain service levels.

Those relying on these forecasts are advised to contact Orion for current information if they are dependent on specific expected loads.

11.2.1 Transpower GXP demand forecast

Table 11.1 shows the capacity of each Transpower GXP supplying our network, alongside present and expected maximum demands over the next 10 years.

Table 11.1 Transpower GXPs – demand forecasts (MVA)

GXP substation	Security standard class	Firm capacity [34]	Peak season	Actual FY25	FY27	FY28	FY29	FY30	FY31	5-year range	10-year range
Bromley 66 kV	A1	220	Winter	144	146	148	150	153	157	157-171	191-209 [35]
Islington 33 kV	B1	109	Winter	76	79	80	82	84	87	87-94	103-112
Islington 66 kV	A1	532 [36]	Winter	433	448	456	469	480	496	496-537	587-639
Hororata 66 kV	C1	N/A [37]	Summer	15	15	15	16	16	16	16-16	17-18
Hororata 33 kV	C1	23	Summer	20	20	19	19	19	20	20-20	20-21
Kimberley 66 kV	C1	N/A [38]	Summer	14	15	15	15	15	15	15-15	15-15
Norwood 66 kV	B1	220	Summer	35	36	36	35	35	35	35-38	48-49
Arthur's Pass 11 kV	D1	3	Winter	0.2	0.2	0.2	0.2	0.3	0.3	0.3-0.3	0.3-0.4
Castle Hill 11 kV	D1	4	Winter	0.6	0.6	0.6	0.6	0.7	0.7	0.7-0.8	0.8-0.9
Coleridge 11 kV	D1	3	Winter	0.3	0.3	0.3	0.3	0.3	0.3	0.3-0.4	0.4-0.4

Note: highlighted cells indicate where our demand forecast will exceed firm capacity.

11.2.2 Zone substation demand forecast

Tables 11.2 (Region A) and 11.3 (Region B), on the following pages, compare the firm capacity of each of our zone substations with the present and forecast demand. Region A covers Christchurch city and outer suburbs, including Prebbleton, while Region B covers Banks Peninsula, Selwyn district and townships.

Growth patterns vary significantly across our network. High-growth areas, such as Halswell, Rolleston, and Lincoln, show sustained increases driven by residential development and business expansion. Urban infill continues across Christchurch, while some eastern areas show more stable demand. Several substations are forecast to exceed firm capacity within the five-year planning horizon, triggering an investigation into possible options including investment in zone substation upgrades and 11 kV network reinforcement.

[34] Firm capacity is the capacity of each site should one item of plant fail under an N-1 contingency. This is different than the operating capacity which is referred to in Schedule 12b – Report on forecast capacity.

[35] This forecast is based on the FY26 network configuration with no consideration for in-progress or planned projects. An in-progress major project will shift Hoon Hay from Islington to Bromley GXP accelerating the capacity breach from mid-2040s to the mid-2030s

[36] Islington has four live transformers with nominally three in service at any one moment.

[37] 66kV busbar and lines are part of the core grid.

[38] 66kV busbar and lines are part of the core grid.

Table 11.2 Region A zone substations – demand forecasts (MVA)[39]

Zone substation	Security standard class	Firm capacity[40]	Peak season	Actual FY25	FY27	FY28	FY29	FY30	FY31	5-year range	10-year range
Addington #1	B2	37	Winter	19	20	20	21	21	22	22-22	26-28
Addington #2	B2	30	Winter	23	23	23	24	24	25	25-25	29-32
Armagh	A2	39	Winter	22	21	22	22	23	24	24-25	28-31
Barnett Park*	B3	15	Winter	10	9	9	9	9	9	9-10	10-12
Belfast*	B3	15	Winter	13	11	12	12	12	13	13-13	17-19
Bromley	B2	48	Winter	39	39	39	40	41	43	43-44	49-53
Dallington	B2	39	Winter	24	23	24	24	25	26	26-26	30-33
Fendalton	B2	42	Winter	37	36	36	37	37	38	38-40	43-47
Halswell	B2	24	Winter	23	22	22	22	23	23	23-26	25-30
Hawthornden	B2	39	Winter	33	36	36	36	37	37	37-41	42-48
Heathcote	B2	39	Winter	29	29	29	30	30	31	31-32	48-52
Hoon Hay	B2	39	Winter	32	29	29	29	30	30	30-32	34-38
Hornby	B2	23	Winter	15	15	15	15	15	16	16-17	19-21
Ilam	B3	12	Winter	14	8	8	9	9	9	9-10	10-12
Lancaster	A2	48	Winter	23	24	25	26	26	27	27-28	32-34
McFaddens	B2	39	Winter	35	33	34	35	35	36	36-37	43-45
Middleton	B2	46	Winter	30	29	30	32	34	36	36-37	44-47
Milton	B2	42	Winter	37	35	36	36	37	38	38-39	44-47
Moffett	B2	23	Winter	19	19	19	19	20	20	20-21	24-26
Oxford Tuam	A2	39	Winter	22	22	23	23	24	25	25-25	29-32
Papanui	B2	50	Winter	36	36	36	37	37	38	38-40	43-47
Prebbleton*	B3	15	Winter	9	9	9	9	10	10	10-10	12-13
Rawhiti	B2	39	Winter	34	32	32	32	33	33	33-35	35-40
Shands	B2	30	Winter	17	16	16	16	17	18	18-18	21-23
Sockburn	B2	37	Winter	25	25	25	26	26	27	27-29	32-36
Waimakariri	B2	48	Winter	24	23	23	24	25	26	26-27	31-33

** Single transformer – security standard limits load to 15MW, 11 kV ties from neighbouring sites provide backup capacity for all load.*
Note: highlighted cells indicate where demand forecast will exceed firm capacity.

[39] Forecasts and actuals may differ as forecasts are weather normalised and assume a steady state network while, actuals contain variations from weather and potentially short-term network reconfiguration.
[40] Firm capacity is the capacity of each site should one item of plant fail under an N-1 contingency. This is different than the operating capacity which is referred to in Schedule 12b – Report on forecast capacity.

Table 11.3 Region B zone substations – demand forecasts (MVA)[41]

Zone substation	Security standard class	Firm capacity[42]	Peak season	Actual FY25	FY27	FY28	FY29	FY30	FY31	5-year range	10-year range
Annat*	C4	8	Summer	4	4	4	4	4	4	4-4	4-4
Bankside*	C3	9	Summer	4	3	3	3	3	3	3-4	4-4
Brookside*	C3	10	Summer	9	9	9	9	9	9	9-9	9-9
Darfield*	B3	10	Summer	6	5	5	5	5	5	5-6	7-8
Diamond Harbour*	B3	9	Winter	3	3	3	3	3	3	3-3	3-4
Dunsandel	A2	24	Summer	19	20	20	20	20	20	20-22	31-33
Duvauchelle	B3	8	Winter	4	4	4	4	4	4	4-5	5-5
Greendale*	C3	10	Summer	7	7	7	7	7	7	7-7	7-7
Highfield*	C3	10	Summer	9	9	9	9	9	9	9-10	11-11
Hills Rd*	B3	10	Summer	8	8	8	8	8	8	8-8	8-8
Hororata*	C3	10	Summer	9	8	8	8	8	8	8-8	8-8
Killinchy*	C3	10	Summer	10	9	9	9	9	9	9-10	11-12
Kimberley	A3	24	Summer	16	15	15	15	15	15	15-15	15-15
Larcomb	B2	24	Winter	25	21	22	23	24	25	25-27	35-36
Lincoln	B3	11	Winter	11	12	12	13	13	13	13-14	17-17
Little River*	C4	3	Winter	2	1	1	1	1	1	1-1	1-1
Motukarara	C4	8	Summer	3	3	3	3	3	3	3-4	4-4
Rolleston	B3	10	Winter	14	12	13	14	15	16	16-16	20-21
Springston	B2	24	Winter	12	16	16	17	17	18	18-19	21-23
Te Pirita*	C3	10	Summer	9	9	9	9	9	9	9-10	10-11
Weedons	B2	24	Winter	16	16	17	18	19	19	19-21	25-26

** Denotes single transformer or line*
Note: highlighted cells indicate where demand forecast will exceed firm capacity.

11.2.3 11 kV feeder utilisation

Our 11 kV network delivers electricity through more than 400 feeders from 47 zone substations (excluding our 5 switching stations) to more than 12,000 distribution transformers across urban and rural areas. These feeders are typically designed to carry 6 to 7 MW, with regular peak loadings up to 4 MW. Approximately 49% of the 11 kV network is underground.

To maintain service reliability and minimise customer interruptions, our HV Security of Supply Guideline sets a maximum threshold of demand that can be exposed to prolonged outages (i.e. the repair time, as opposed to switching time) following a feeder fault. To meet the requirements of the guideline, our 11 kV network must be able to transfer load between adjacent feeders, and in many cases, across zone

[41] Forecasts and actuals may differ as forecasts are weather normalised and assume a steady state network, while actuals contain variations from weather and potentially short-term network reconfiguration.
[42] Firm capacity is the capacity of each site should one item of plant fail under an N-1 contingency. This is different than the operating capacity which is referred to in Schedule 12b – Report on forecast capacity.

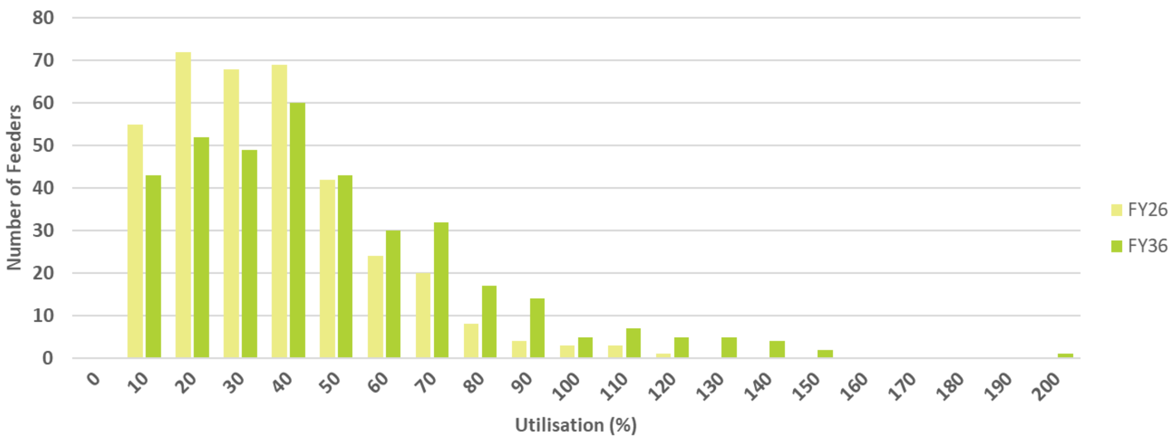
substations, to maintain supply under N-1 conditions, particularly at sites with a single transformer or subtransmission circuit.

Figure 11.5 compares actual feeder utilisation in FY26 with forecast feeder utilisation in FY36. While the overall distribution remains relatively stable, there is a notable increase in the number of feeders operating at higher utilisation levels as demand growth continues across our network. Feeders operating above acceptable utilisation thresholds present different risks depending on their configuration:

- For radial feeders, 100% utilisation is the thermal capacity of the circuit. Exceeding this risks conductor damage, fault initiation, and potential safety concerns.
- For parallel ring feeders, 100% utilisation represents the N-1 capacity of the ring; a fault on any arm of the ring would immediately overload the remaining arms, risking a cascading failure across the entire ring.

This is of particular concern because parallel rings typically serve significantly more customers than radial feeders, meaning the consequence of a cascading fault, in terms of both the number of customers affected and the duration of outage, is materially higher. The increasing proportion of feeders approaching or exceeding 100% utilisation in FY36 therefore represents a growing risk to network reliability and customer outcomes.

Figure 11.5 11kV feeder utilisation – comparison between FY26 and FY36



11.2.4 LV network constraints

Our low voltage (LV) network supplies power to 99.7% of customers through more than 11,800 LV networks. Each network consists of a distribution transformer serving a small group of customers, from one to more than 300. Approximately 68 percent of our LV network is underground.

LV demand growth is driven by the same factors affecting our higher voltage networks: population increase, urban development, and electrification of transport and heating. However, LV networks experience more localised and variable load patterns due to lower customer diversity.

Without proactive investment, constraint-related issues will increase, particularly during colder winters when both heating and EV charging place additional pressure on our network. These issues will lead to more customer complaints and reduced reliability in localised areas, which does not align with customer expectations for a reliable power supply with targeted improvements where issues occur.

In Region B, the rural network has a higher proportion of pole-mounted distribution transformers and longer, more dispersed LV feeders. These areas often experience lower load diversity and peakier demand profiles, which can lead to more frequent or severe constraints. In contrast, Region A is more urbanised, with a denser underground network and higher diversity of customer loads. While constraints are still present, they are generally less severe due to shorter feeder lengths and more interconnected topology.

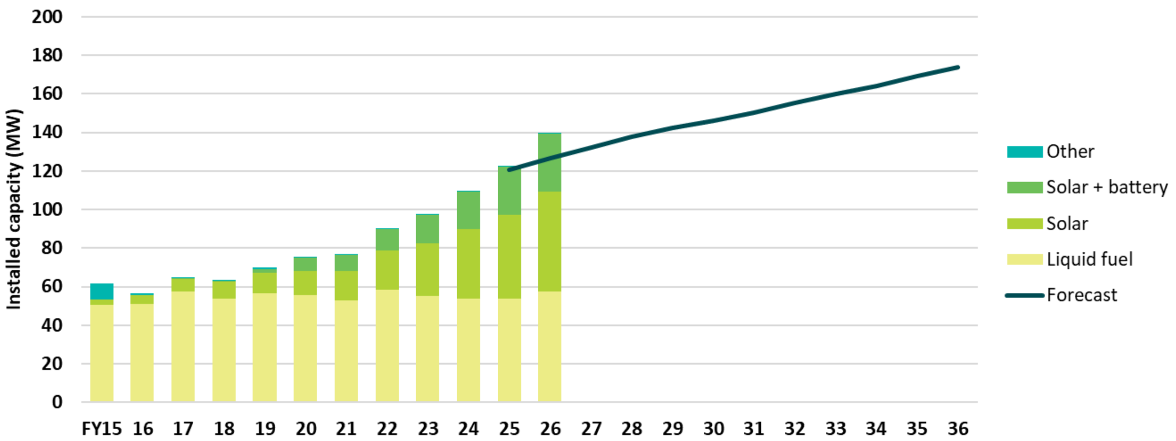
Unlike our higher voltage network, we do not design for N-1 security at the LV level. This means constrained networks have no capacity headroom and risk delivering unreliable service through overloaded equipment and fuse failures, or non-compliant voltage levels.

11.2.5 Distributed generation forecast

Our network has experienced steady growth in distributed generation), predominantly in the residential and commercial solar photovoltaic systems. As of FY26, we have approximately 11,500 distributed generation connections totalling around 140 MW of installed capacity. Approximately 3-4% of network connections have distributed generation at their connection. In some areas of our network, this is around 8-10%, particularly around Rolleston and West Melton.

Figure 11.6 shows the historical and forecast distributed generation capacity growth under the Central Forecast scenario. Historical growth has been driven by large diesel and liquid fuel backup generators, alongside increasing uptake of residential and commercial solar installations. Since 2023, we have also seen emerging adoption of battery energy storage systems, typically paired with solar generation.

Figure 11.6 Historical and forecast distributed generation on Orion's network, as of 31 March 2026



Our Central Forecast assumes no further growth in thermal generation (diesel and liquid fuel backup generators), with all future growth coming from solar and battery installations. We forecast distributed generation capacity to grow to 167 MW by FY36, an increase of approximately 40% over the 10-year period. This growth is driven primarily by:

- continued uptake of residential solar systems as technology costs decline
- commercial and industrial solar installations seeking to reduce electricity costs or participate in the wholesale market
- increasing adoption of battery energy storage systems, particularly when paired with solar generation, enabling customers to store solar energy for use during peak pricing periods.

Our analysis indicates that distributed generation growth in the AMP period is not expected to create material network constraints requiring capital investment at the 11 kV or LV levels. The distributed nature of customer generation, combined with relatively modest penetration levels and our network's existing voltage management capability, means our network can accommodate forecast DER growth without requiring immediate reinforcement.

However, we recognise that distributed generation can create localised network management challenges if left unmanaged, including harmonics, voltage fluctuations, power quality impacts, and potential network congestion during periods of high generation and low demand.

To manage these emerging challenges, and prepare for higher penetration levels beyond the AMP period, we have developed a Congestion Management Policy, available on our website, to guide connection decisions and manage network access where hosting capacity is constrained. This policy provides transparency for customers and ensure fair and efficient use of network capacity.

We will continue to refine our understanding of distributed generation hosting capacity at the LV and 11 kV feeder level, using network modelling and monitoring of actual generation patterns to inform connection decisions.

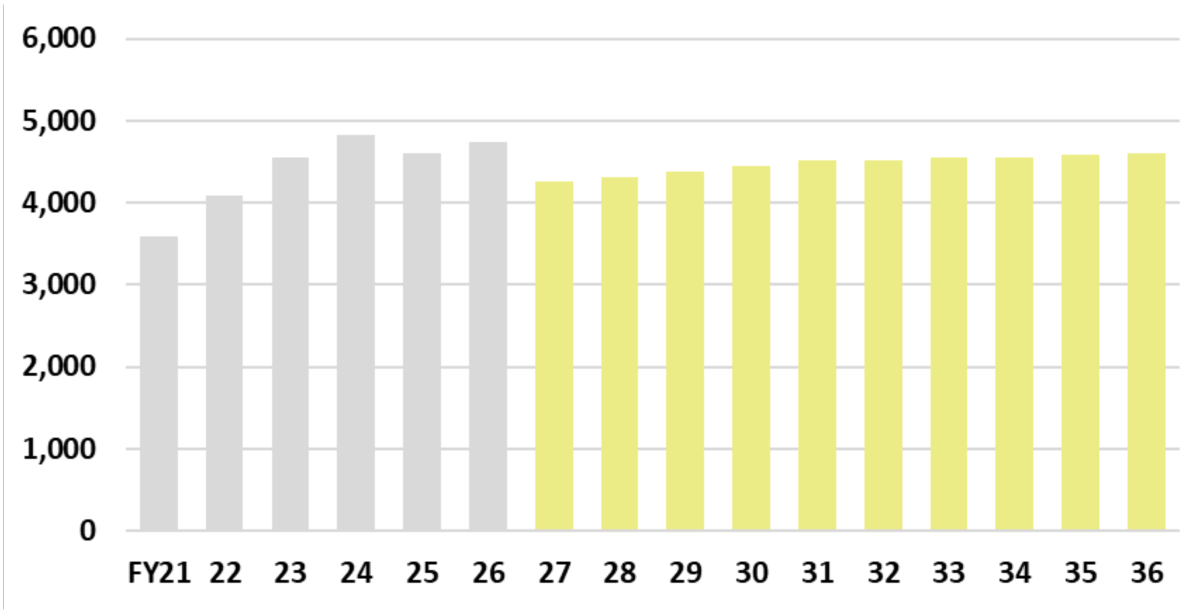
We are also actively engaged in industry forums and monitoring regulatory developments that may affect distributed generation, including changes to the Electricity Industry Participation Code 2010 regarding distribution network pricing and access, updates to the permitted voltage range on LV electricity networks that may affect network design parameters, increases to default export limits, and connection standards and technical requirements for inverter-based resources.

11.2.6 Customer connections forecast

Our network continues to experience strong customer growth driven by population increase and urban development across our region. Between FY21-FY26, we have connected around 4,400 new connections annually, after accounting for disconnections and connection alterations. We expect new connection volumes to moderate slightly in the early years of the AMP period, before gradually picking up again as population growth accelerates. Connections in FY26 increased to approximately 4,700; we expect this to temporarily ease back, then gradually increase again, reaching approximately 4,600 per year by FY36.

Figure 11.7 shows this pattern, which reflects housing market cycles, migration trends, industrial electrification, and how our region is likely to develop over the coming decade.

Figure 11.7 New customer connections forecast (net connections per year)



The capex required to deliver these connections, including network extensions and capacity augmentation, is detailed in Section 12.

11.2.7 Electricity consumption forecast

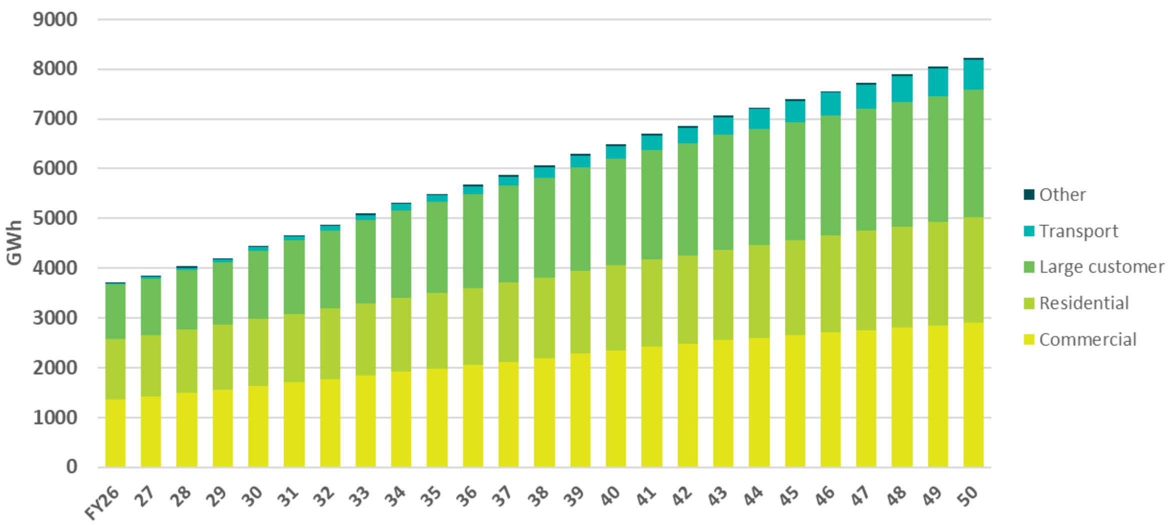
Our electricity consumption forecast uses a two-phase econometric approach developed and independently validated by Frontier Economics.

First, the baseline consumption model uses monthly billing load by customer category[43] as its starting point. Residential, irrigation, and streetlighting consumption is estimated using an OLS regression model with heating and cooling degree days and ICP growth as the primary drivers. Commercial, major customer connections, and large customer connections consumption is forecast using a driver-based approach tied to GDP growth within our network area.

Then, post-model adjustments are then applied to account for factors not well captured in historical trends, including EV uptake, process heat electrification, weather normalisation, and distributed solar generation (netted off as a reduction to grid demand). These adjustments use the same assumptions as those applied in our peak demand forecast, described in Section 10.2.

Figure 11.8 shows our forecast annual electricity consumption from FY26 to FY50 under the Central Forecast, broken down by customer category and adjusted for post-model factors.

Figure 11.8 Annual electricity consumption forecast by category[44] – FY26 to FY50



Under our Central Forecast, total annual consumption is projected to grow from approximately 3,700 GWh in FY26 to 8,200 GWh by FY50. Over the AMP period, growth is primarily driven by population increases and associated residential and commercial load growth, with transport electrification and process heat conversions becoming more material beyond FY36.

[43] Orion's customer categories include residential low and standard users, general commercial connections, streetlighting, irrigation, major customer connections, and large capacity connections. Further detail may be found in our Pricing guides and information, available on our website: https://www.oriongroup.co.nz/our-story/pricing.

[44] The "large customer" category includes both LCC (large capacity connections) and MCC (major Customer connections). The "other" category includes both streetlighting and irrigation.

11.3 Current and forecast network security gaps

To ensure our network remains reliable and resilient, we continually monitor current loading and regularly perform power-flow contingency modelling to check compliance against our HV Security of Supply Guideline.[45] Each GXP and zone substation is assigned a Security Standard Class, which outlines our restoration targets under different contingency scenarios. A security gap is where current or forecast demand exceeds the network's ability to maintain or restore supply within the timeframes specified in the Security Standard Class. This can occur when asset loading exceeds firm capacity (the capacity available when one major asset fails), or when the network configuration limits our ability to transfer load to maintain supply during contingencies.

The subsections below identify all security gaps, both existing and forecast, at Transpower's GXPs, and our zone substations and subtransmission circuits. Although gaps exist across our network, not all require immediate attention. Some gaps represent extremely low-probability events or may not be economical to address because supply restoration can be managed operationally through remote switching from our Network Control Centre. Where gaps do not trigger immediate investment, we explain the reasoning in the subsections below.

The projects and programmes we are implementing to address certain security gaps are detailed in Section 12, including options analysis, cost-benefit assessments and project timings.

11.3.1 Transpower GXP security gaps

Table 11.4 identifies current and forecast security gaps at Transpower's GXPs that supply our network. These gaps primarily relate to limitations in restoring supply following dual transformer failures at Islington and bus outages at Hororata, as well as potential capacity constraints at Islington under higher growth scenarios. Where gaps exist, we work with Transpower to coordinate solutions or implement our own network reinforcement to improve load transfer capability.

Table 11.4 Transpower GXP security gaps

GXP substation	Security standard class gap	Gap detail	Proposed solution	Resolved year
Islington 33 kV	A1 / B1	Full restoration unobtainable for an Islington 220/33 kV dual transformer unplanned outage (N-2).	Partially resolved by the construction of the Templeton zone substation commercial growth project. Further reinforcement, yet to be scoped, is required to increase capacity.	FY31 (partial)
Islington 66 kV	A1	Possible forecast N-1 capacity breach if load growth is higher than the planned forecast scenario.	Load transfer to Norwood GXP	TBD
Hororata 66kV	C1	Loss of all Hororata GXP load for a single unplanned 66 kV bus outage (restorable)	Load transfer to Norwood GXP	TBD
Hororata 33kV	C1	Only partial restoration achievable for a Hororata 66/33 kV dual transformer failure (N-2)	Load transfer to Norwood GXP	TBD

[45] See Appendix F – Security of Supply Guide for further details.

11.3.2 Zone substation and subtransmission security gaps

Table 11.5 identifies current and forecast security gaps at our zone substations and subtransmission circuits. These gaps arise where forecast load growth exceeds firm capacity, or where existing network configuration limits our ability to transfer load under contingency conditions. Solutions range from zone substation capacity upgrades to new substations and subtransmission reinforcement.

Table 11.5 Zone substation and subtransmission security gaps

Substation / circuit	Security standard class gap	Gap detail	Proposed solution	Resolved year
Addington #2	B2	Firm capacity forecast to potentially exceed within 10 years	Transformers upgraded as part of asset renewals	FY31
Belfast	B2	Firm capacity forecast to exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD
Bromley	B2	Firm capacity forecast to exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD
Fendalton	B2	Firm capacity forecast to exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD
Halswell	B2	Firm capacity forecast to potentially exceed within 5 years	Halswell North 11 kV reinforcement and load transfers	FY30
Hawthornden	B2	Firm capacity forecast to potentially exceed within 5 years	Hawthornden to Moffett 11 kV Reinforcement and load transfers	FY30
Heathcote	B2	Firm capacity forecast to exceed within 10 years	Likely 11 kV reinforcements and load transfers	TBD
McFaddens	B2	Firm capacity forecast to exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD
Middleton	B2	Firm capacity forecast to potentially exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD
Milton	B2	Firm capacity forecast to exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD
Moffett	B2	Firm capacity forecast to exceed within 10 years	Templeton commercial growth project	FY32
Rawhiti	B2	Firm capacity forecast to potentially exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD
Dunsandel	A2	Firm capacity forecast to exceed within 10 years	Engagement with major customer	TBD
Highfield	C3	Capacity forecast to exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD
Killinchy	C3	Capacity forecast to exceed within 10 years	Lower Selwyn Growth project – Stage 1	FY36
Larcomb	B2	Firm capacity forecast to exceed within 5 years	Likely 11 kV reinforcement and load transfers	TBD
Lincoln	B3	Firm capacity exceeded	Lincoln Growth project	FY31
Rolleston	B3	Firm capacity exceeded	New Burnham zone substation project	FY27
Te Pirita	C3	Capacity forecast to exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD

Table 11.5 Zone substation and subtransmission security gaps				
Substation / circuit	**Security standard class gap**	**Gap detail**	**Proposed solution**	**Resolved year**
Weedons	B2	Capacity forecast to exceed within 10 years	Likely 11 kV reinforcement and load transfers	TBD

11.3.3 11 kV and LV security gaps

Where loading for 11 kV feeders is forecast to approach or exceed 90% of their nominal capacity under normal conditions, we conduct detailed contingency planning to assess whether reinforcement is needed to maintain security of supply under N-1 conditions.

Our analysis has identified that 29 feeders are already operating at this capacity level or will reach or exceed that capacity level by FY36, strengthening the need for proactive reinforcement of the network to maintain performance and avoid reactive investment. These gaps arise from a combination of forecast demand growth and limitations in existing feeder capacity or transfer capability between adjacent substations.

Our latest modelling shows that 469 LV networks, or 4% of our total LV networks, are already exceeding equipment design ratings or breaching voltage constraints. By FY36, we expect more than 1,055 LV networks to face thermal or voltage constraints and require remediation.[46]

Without investment, these constraints will limit our ability to connect new customers and support our regions' growth and decarbonisation. For further details on the proposed solutions, refer to Section 12.

[46] Thermal constraints occur when distribution transformers exceed nameplate capacity or conductors exceed seasonal ratings. Voltage constraints occur when networks experience voltage outside regulatory compliance limits.

12

12. Network development programme

Network development investments address the capacity and security constraints identified through demand and generation forecasting and network modelling. These investments will ensure we maintain appropriate capacity and security of supply to support regional economic growth, decarbonisation, and electrification across Central Waitaha Canterbury.

The network development programme responds to two of our investment priorities:

1. **Supporting strong population and demand growth**: by extending and upgrading the network at emerging constraint points to accommodate one of the fastest regional population growth rates in New Zealand.
2. **Preparing for future energy needs**: by exploring and implementing non-network solutions that defer traditional network investment, where cost-effective.

Section 11 quantified the demand growth and identified where this growth could create network constraints which will require investment. Our planning approach is detailed in Section 10 – Network development approach.

Investment planning incorporates the lead time required to plan and deliver projects within the network development programme. Planned includes land acquisition, detailed design, equipment procurement (which can take up to 18 months for major equipment), and construction. Major 66 kV or 33 kV projects typically take up to 4 years from commitment to commissioning, while 11 kV and LV projects take around 18 months.

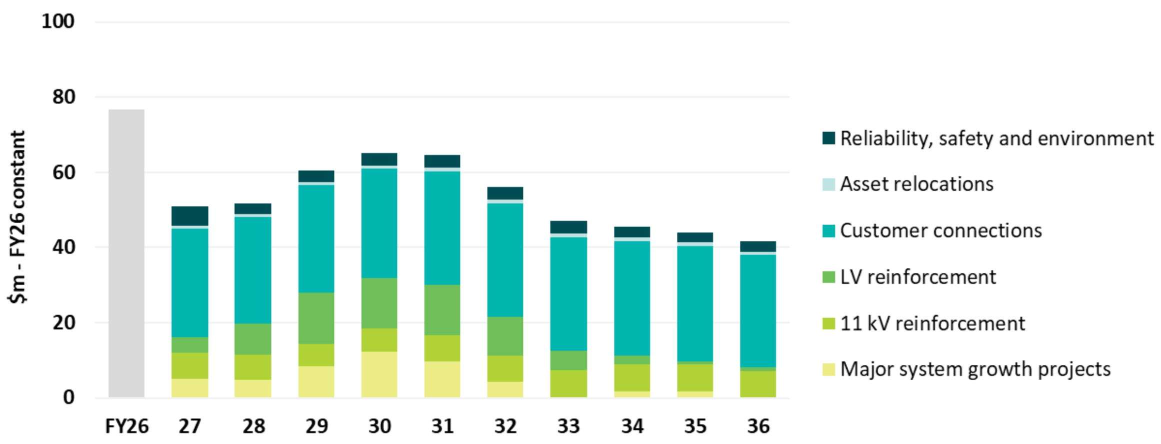
Our network development programme comprises six portfolios:

1. **Major system growth projects**: large-scale projects addressing significant capacity constraints or security gaps (Section 12.2).
2. **11 kV reinforcement**: distribution network reinforcement through reconfiguration work and capacity-driven projects (Section 12.3).
3. **LV reinforcement**: low voltage (LV) network reinforcement addressing thermal and voltage constraints (Section 12.4).
4. **Customer connections**: new customer connections and modifications to existing connection points (Section 12.5).
5. **Asset relocations**: works to accommodate third-party infrastructure projects that require the relocation, modification, or undergrounding of existing network assets (Section 12.6).
6. **Reliability, safety, and environment (RSE)**: works to maintain or improve network performance, manage safety risks, and meet environmental, regulatory or other legislative obligations (Section 12.7).

12.1 Investment overview

Our network development investment totals $527.2 million over the FY27-FY36 period. Figure 12.1 shows the total proposed network development capex per annum by portfolio.[47] The following sections present each portfolio in detail.

Figure 12.1 Orion's total network development programme capex per annum[48]



Projects in the first two years of the AMP period are firm commitments with confirmed scope and timing. Projects in the latter four years reflect our strategic investment direction, recognising that forecasts are less certain in the longer term and specific project parameters will be confirmed through subsequent AMP planning cycles.

We have identified a number of major system growth projects where non-network solutions could defer investment by 1 to 2 years, if successfully procured at sufficient scale. We have also assumed non-network solutions will defer some 11 kV reinforcement projects across the programme and will pursue non-network solutions for LV reinforcement where technically feasible and economically viable. While these approaches are an important part of our investment strategy, the extent to which they can defer capital investment depends on market availability and the pace at which contracted flexibility services develop. Non-network solutions identified in this chapter have not yet been procured, and the programme has been developed on the basis that traditional network investment remains the primary response where flexibility cannot be confirmed at sufficient scale or firmness.

To provide early visibility to flexibility service providers, we have published a flexibility opportunity viewer on our website, which identifies areas where constraints are likely to emerge during the AMP period.[49] This information is intended to give flexibility service providers an indication of future opportunities and provide sufficient time to develop capability ahead of flexibility market engagement via a tender. We will update this map on an on-going basis to reflect revised demand forecasts and network modelling.

[47] Opex associated with the procurement of non-network solutions, and capex for the procurement of non-network equipment to support DER connections and manage increased network complexity and demand are included in Section 9 – Transforming our network.
[48] Values shown are net capex after customer contributions where applicable. Refer to the customer connections and asset relocations portfolios for further detail.
[49] See: https://www.oriongroup.co.nz/your-energy-future/flexibility-opportunities-viewer

12.2 Major system growth projects portfolio

Major system growth projects address significant capacity or security constraints identified through the investment process previously described. These investments typically involve new zone substation development, subtransmission reinforcement, or substantial distribution network augmentation.

12.2.1 Investment summary

Figure 12.2 and Table 12.1 summarise our major system growth investments planned for the AMP period. Additional project information, including investment need, options analysis, non-network solution assessments, and selected solutions are provided in *Appendix D – Major systems growth projects portfolio*.

Figure 12.2 Orion's total major system growth portfolio capex per annum

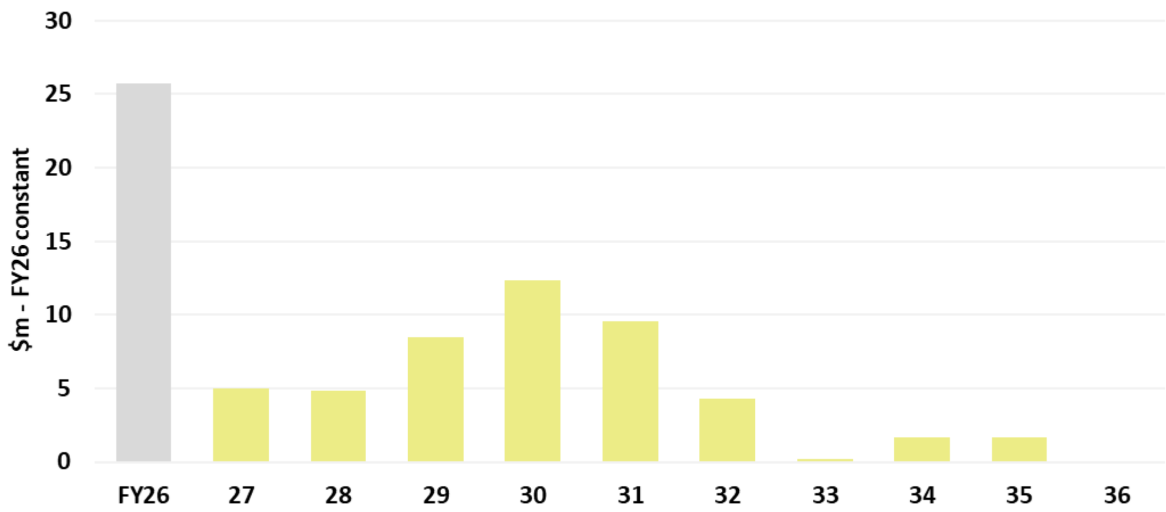


Table 12.1 Orion's major system growth projects portfolio capex ($m, FY26 constant)

Project	From	To	Capex
Milton Hoon Hay cables + switchroom This is a continuation of projects identified in prior AMPs to enable connection of the new 66kV cable circuits from Halswell zone substation and Milton zone substation.	FY27	FY27	1.0
New Burnham zone substation This is a continuation of a project identified in prior AMPs to develop a new 66/11 kV 23 MVA capacity zone substation at Burnham.	FY27	FY27	3.8
Lincoln township growth This project will establish a new 33 kV Greenpark zone substation to replace the aging, space-constrained Lincoln zone substation and meet forecast 30% demand growth in one of New Zealand's fastest growing regions.	FY28	FY30	13.9
Malvern industrial growth This project will establish a new Norwood 11 kV supply point to enable a 3.7 MW staged upgrade at an abattoir in Malvern. The new supply point leverages recently completed site establishment works at Norwood 66 kV zone substation, resolving capacity and voltage constraints on the existing Highfield supply while providing additional capacity for wider area growth.	FY27	FY29	2.4
Templeton commercial growth This project will construct a new 66/11 kV substation to enable electrification of the Christchurch Men and Women Prisons' heating systems and provide reliable supply for a new proposed vertical farm, removing constraints on the existing 11 kV feeder.	FY29	FY31	11.2

Table 12.1 Orion's major system growth projects portfolio capex ($m, FY26 constant)			
Project	**From**	**To**	**Capex**
Emergency spare transformers This project will procure critical spare power transformers (one 23 MVA and one 10 MVA) to reduce extended outage risk following catastrophic transformer failures and enable timely power restoration.	FY28	FY29	3.0
Lyttelton Port Company growth This project will address capacity limitations by installing a fourth 11 kV circuit from Heathcote zone substation to Lyttelton and reinforcing an existing 11 kV circuit.	FY30	FY32	9.1
Lower Selwyn growth – Stage 1 Additional 0.5 MW growth over forecast in FY28-32 period may trigger the need for additional power transformer at Killinchy zone substation to maintain nominal supply.	FY33	FY35	3.6

12.2.2 Contingent projects

Our demand forecasts have identified one project, Lower Selwyn growth – Stage 1, that will likely be required in the latter part of the AMP period. We believe that this project has a reasonable likelihood of being brought forward due to significant demand growth in the area.

While this project has been included in our AMP base forecast, we have classified this project as a CPP contingent project because it has identified demand triggers that may bring it further forward.

This project has been verified by the independent verifier as part of our CPP Application process.

12.2.3 Nascent projects

Nascent projects represent potential future investments where we have identified speculative point loads that may materialise during the AMP period, but insufficient certainty exists to forecast timing or define specific solutions. These projects represent point load additions beyond the demand forecasts presented in Section 11.

These projects, outlined in Table 12.2, are monitored as part of our ongoing planning. As certainty increases, they may transition to contingent or firm projects in future AMP updates. For clarity, nascent projects are not included in our AMP schedules or financial forecasts.

Table 12.2 Orion's identified nascent projects ($m, FY26 constant)		
Project	**Estimated capex range**	**Description**
Lower Selwyn growth – Stage 2	2.5 – 20	Residential growth in townships of Doyleston, Leeston, and Southbridge over and above forecast, exceeding substation and distribution line capacity in the area.
Region B subtransmission	10 – 20	If demand from electrification and/or new industrial processes, such as hydrogen production, constrains Bromley and Islington 66 kV grid exit points (GXPs) in Christchurch city area, investigate expansion of subtransmission network in Region B to enable further utilisation of Norwood GXP.
Rolleston area growth	2 – 30	A combination of higher than forecast growth could trigger the need for a new major project to provide additional capacity in or around the Rolleston township or industrial area.
Northern Christchurch capacity	5 – 30	If industrial and residential demand in Belfast and/or Marshland area exceeds security of supply thresholds of distribution network and/or zone substation capacity, then this may trigger the need to provide additional capacity in the area. Scope depends on extent and precise location of demand increase.
Shands Road zone substation capacity upgrade	10 – 20	Industrial demand forecasting is challenging, due to end load intensification being anything from warehousing to high-energy manufacturing or industrial decarbonisation. Shands Road zone substation is in the heart of an industrial area,

Table 12.2 Orion's identified nascent projects ($m, FY26 constant)		
Project	**Estimated capex range**	**Description**
		with ample vacant lots and established industries that may decarbonise process heat. Only 2 MW headroom at end of AMP period, so a few medium sized or a single large point load increase occurring will likely push the zone substation and distribution network beyond the security of supply firm capacity. The scope of the required solution will depend on capacity requirements.
Darfield area growth	15 – 25	We have received two capacity letters that have signalled the intent of developing in-excess of 1,200 residential lots over and above the anticipated residential subdivision growth in the base forecast. This additional growth, as well as decarbonisation of industrial sites, will outstrip the supply capacity of Darfield zone substation. A major project may be required to meet the growth and to maintain current levels of supply security.
Hororata 66 kV zone substation	8 – 20	The current voltage stability of the subtransmission network around Hororata substation limits the ability to absorb large quantities of generation. Further large generation connections may trigger the need to strengthen the 66 kV network connections back to Norwood GXP.
Malvern industrial growth – Stage 2	8 – 12	The abattoir customer in Malvern has indicated that they have future expansion plans for their site. This may require additional capacity beyond the capability of Stage 1.
Potential total	**60.5 - 177**	

12.3 11 kV reinforcement portfolio

This portfolio addresses existing and emerging capacity constraints on our 11 kV distribution network. Historically, 11 kV investment operated reactively, driven by specific customer connections or localised constraints. However, sustained demand growth has necessitated a transition to proactive constraint identification through enhanced contingency planning processes implemented during FY25.

11 kV reinforcement requirements fall into two categories:

1. Reconfiguration of existing 11 kV feeders releases latent capacity to meet growth and ensures contingency switching can achieve security of supply criteria. This work comprises numerous smaller-scale projects undertaken on a relatively consistent basis year-on-year.
2. Capacity-driven reinforcement projects install new feeders, upgrade conductor capacity, or deploy other solutions, such as voltage support devices, where existing capacity is exhausted and reconfiguration options prove insufficient. Feeders forecast to exceed 90% utilisation under contingency conditions (90% of N capacity for radial feeders; 90% of N-1 capacity for primary ring feeders) are flagged for reinforcement, with non-network alternatives potentially deferring projects where demand flexibility or other non-network solutions can provide adequate support.

12.3.1 Investment summary

Figure 12.3 and Table 12.3 summarise our 11 kV reinforcement investments planned for the AMP period.

For AMP years 1-3 (FY27-29), we have individually scoped 7 capacity-driven projects. For AMP years 4-10 (FY30-36), projects are not yet individually scoped, but investment is forecast based on network constraint modelling which indicates approximately two reinforcement projects will be required per year.

Non-network solutions present opportunities to defer certain capacity-driven projects where demand flexibility can provide adequate support during peak periods or contingency conditions. Based on our assessment of current opportunities, we have assumed one project could be deferred every two years, beginning from FY29, using non-network solutions, with opex funding these alternative solutions.

To ensure investment occurs only when required, we review demand forecasts annually to assess whether project deferral is appropriate or whether the project scope remains optimal. While we always confirm demand forecasts before committing to investment, the developing non-network solution market may require earlier commitment compared with traditional network investments. However, as we have reasonable confidence that population growth will continue in the areas where non-network solutions are planned, this means earlier commitment does not present a risk of material over-investment.

Figure 12.3 Orion's total 11 kV reinforcement portfolio capex per annum

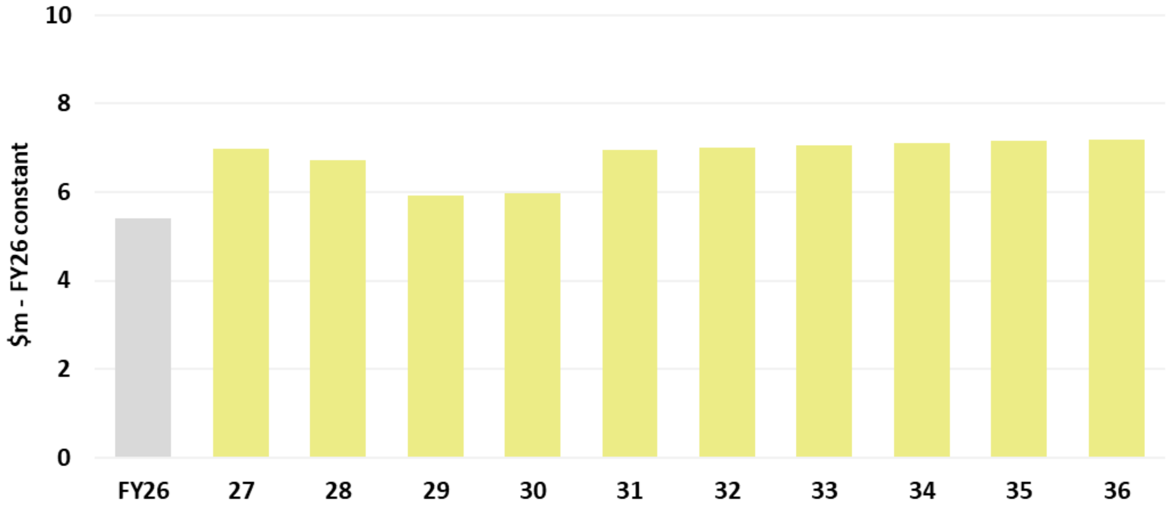


Table 12.3 presents the individually scoped 7 capacity-driven reinforcement projects for the beginning of the AMP period. These projects have undergone detailed constraint analysis and solution development through our network planning processes.

Table 12.3 Orion's scoped 11 kV capacity-driven reinforcement projects ($m, FY26 constant)

Project	Project number	Investment need	From	To	Capex
Halswell South 11 kV reinforcement – stage 2	1959	This is for the completion of a project started in FY26, to resolve a growing constraint on the 11 kV distribution network in the southern part of the Halswell zone substation supply area, driven by new subdivision development.	FY27	FY27	2.3
Annat STATCOM	1926	It is currently not possible to resupply all load fed from the Annat zone substation under a N-1 scenario. This is due to the fringe location of the zone substation resulting in voltage constraints under a N-1 scenario. The relocation of an unused STATCOM to the zone substation will provide sufficient voltage compensation to mitigate this constraint.	FY27	FY27	0.3
Belfast Rd overhead reinforcement	1426	It is currently difficult to shift load from Rawhiti zone substation to Belfast zone substation due to an undersized section of overhead conductor on Belfast Rd. Reconductoring this section of overhead will remove the constraint.	FY27	FY27	0.1
Ryans Rd Industrial	1958	There are plans for a new commercial and industrial subdivision on the corner of Ryans Rd and Pound Rd. This will require the distribution network back to Hawthornden zone substation to be reinforced.	FY27	FY29	3.1
Weedons Ross Rd	791	As West Melton continues to grow the distribution network back to Weedons zone substation will need to be reinforced. This will allow for the continued expansion of the township.	FY28	FY28	1.7
Halswell North 11 kV reinforcement	1569	As the load on Halswell zone substation continues to grow there is an increasing need to reinforce the network towards	FY29	FY29	0.9

Table 12.3 Orion's scoped 11 kV capacity-driven reinforcement projects ($m, FY26 constant)

Project	Project number	Investment need	From	To	Capex
		Hoon Hay zone substation to allow for pre and post fault load transfers. Non-network solutions may be used to defer this project.			
Hawthornden to Moffett 11kV reinforcement	1662	As the load on Hawthornden zone substation continues to grow there is an increasing need to reinforce the network towards Moffett zone substation to allow for pre and post fault load transfers.	FY29	FY29	1.3

12.4 LV reinforcement portfolio

This portfolio addresses existing and emerging capacity and voltage constraints on the 400 V LV network through upgrading or installing distribution transformers, overhead conductors, underground cables, and associated equipment.

Network modelling forecasts that LV constraints will increase to more than 1,055 constrained networks by FY36 without proactive intervention. Unlike higher voltage networks, where we design for N-1 security standards, we do not provide contingency capability at the LV level. Consequently, when constraints emerge, we cannot reduce the security level; rather, there is risk of delivering unreliable service through outages associated with overloaded equipment and fuses, and non-compliant service outside voltage regulations.

Constraints on the LV network may occur as thermal issues, where distribution transformers or conductors exceed equipment design ratings, or as voltage compliance issues, where networks breach voltage regulations. The prevalence of constraints is increasing due to housing intensification, particularly in older Christchurch areas supplied by aging lower-capacity overhead conductors and underground cables, combined with EV adoption and distributed generation deployment placing demands on LV networks not originally designed to accommodate two-way power flows.

Historically, network growth was managed through reactive responses to connection requests and operational feedback. However, the scale and pace of change driven by electrification and housing intensification necessitates proactive intervention. We have enhanced LV constraint identification capability through improved modelling methodologies and enhanced data collection, enabling forecasting of where constraints will emerge and facilitating proactive remediation before constraints limit connections or compromise reliability.

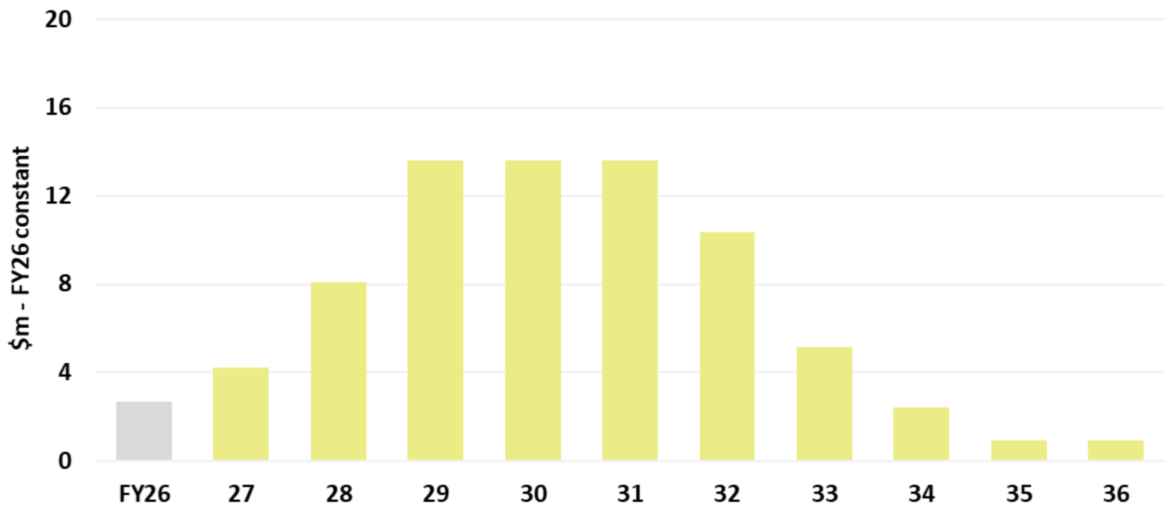
12.4.1 Investment summary

Figure 12.4 summarises our LV reinforcement investments planned for the AMP period.

Over the 10-year AMP period, this investment will remediate identified constraints. The investment profile reflects a prioritised remediation strategy, with higher investment in the early-to-mid part of the AMP period addressing the existing constraint backlog and emerging high-priority constraints, then tapering investment in later years as the backlog is addressed, while maintaining ongoing investment for continued demand growth.

To ensure investment occurs only when required, we review demand forecasts annually and reprioritise constraints based on updated network modelling. This approach addresses the most critical constraints while maintaining flexibility to respond to changing demand patterns. Where technically feasible and economically viable, during this AMP period, we plan to procure non-network solutions to resolve voltage and capacity constraints as alternatives to traditional reinforcement.

Figure 12.4 Orion's total LV reinforcement portfolio capex per annum



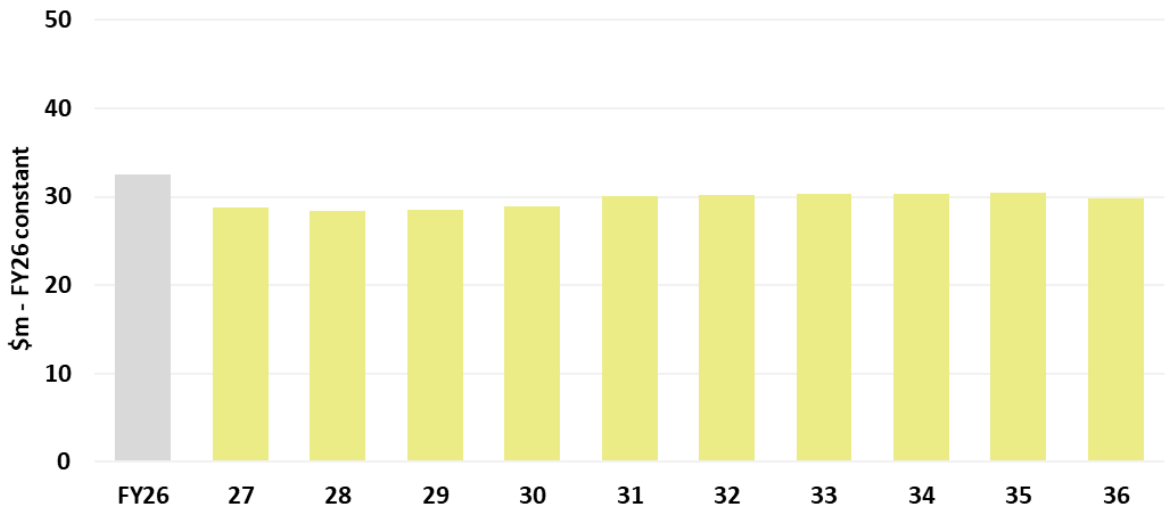
12.5 Customer connections portfolio

Customer connection capex facilitates new customer connections to our network and modifications to existing connection points. This portfolio responds directly to customer-initiated requests, supporting local economic activity and enabling regional development. Investment in this portfolio is recoverable in total, or in part, through capital contributions from connecting parties

12.5.1 Investment summary

Figure 12.5 summarises our forecast net customer connections investment, after capital contributions, for the AMP period.

Figure 12.5 Orion's net customer connections portfolio capex per annum



12.6 Asset relocations portfolio

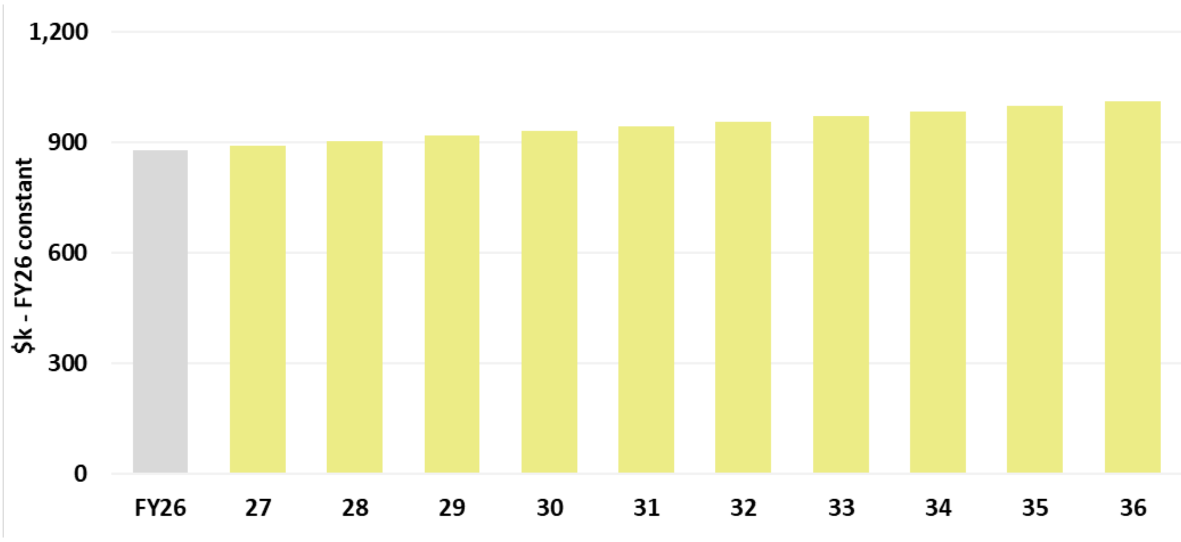
Asset relocations address third party requests to move or underground our network assets to enable external projects, such as road widening, utility works, and regional development initiatives. This portfolio is externally driven and directly supports regional growth by facilitating infrastructure development projects led by organisations such as NZ Transport Agency Waka Kotahi, local councils, and developers.

Investment in this portfolio is recoverable in total, or in part, through capital contributions from requesting parties. This ensures appropriate cost allocation between customers and those directly benefiting from the relocations.

12.6.1 Investment summary

Figure 12.6 shows our historical and forecast net, after customer contribution, investment for this portfolio.

Figure 12.6 Orion's net asset relocations portfolio capex per annum



Our forecast is based on FY25 expenditure projected forward with a 1.42% annual growth factor aligned with expected network growth, recognising that relocation volumes typically grow proportionally with overall infrastructure development activity across our regions.

The forecast assumes no large-scale relocations have been identified for the AMP period. While historical expenditure shows significant year-on-year variation due to the opportunistic nature of third-party projects, using the most recent year as our base provides a reasonable starting point for planning purposes. We review this forecast annually as part of our AMP process to ensure it reflects emerging external project requirements.

12.7 Reliability, safety, and environment portfolio

The reliability, safety and environment (RSE) portfolio covers targeted investments that sit alongside our renewals and network development programmes. These investments address three distinct needs:

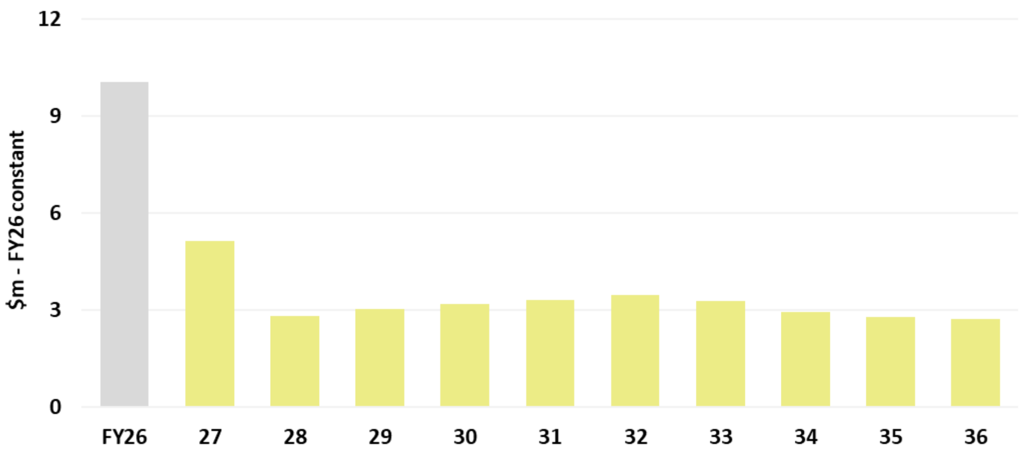
- **Quality of supply:** investments are targeted at managing network performance to meet customer expectations and ensure they continue to receive an appropriate level of service quality.
- **Legislative and regulatory:** investments ensure we meet electrical safety, health and safety requirements, and other legal obligations.
- **Other reliability, safety and environment:** investments go beyond our core quality of supply obligations and regulatory compliance to target specific safety improvements and environmental initiatives.

RSE investments tend to be smaller, targeted interventions rather than large-scale programmes, responding to identified risks, compliance obligations, or localised reliability issues. Examples include targeted works to improve outage response capability, upgrades at substations to manage oil containment, stormwater control or spill protection, and investments to address known safety or environmental hazards such as earth potential rise issues or seismic vulnerabilities.

12.7.1 Investment summary

Figure 12.7 shows our historical and forecast net investment for this portfolio. Table 12.4 summarises our RSE investments planned for the AMP period.

Figure 12.7 Orion's total RSE portfolio capex per annum



Our proposed annual RSE capex is lower than recent historical spend, primarily because a safety-focused fuse relocation programme is scheduled for completion in FY27, reducing spend in subsequent years. Beyond this reduction, our proposed spend reflects a stable ongoing programme of work across quality of supply and other RSE categories. Tables 12.4 and 12.5 summarise the planned programmes within the first five years of the AMP period.

Our targeted quality of supply investments are expected to improve service quality for a relatively small number of customers that are currently experiencing a lower level of service than average. Overall, we expect that these investment will assist to maintain average service performance.

Table 12.4 Orion's quality of supply investments ($m, FY26 constant)		
Programme	**Description**	**Capex**
Rectifying poor performing feeders (continuation)	We are planning to install reclosers on overhead lines that frequently trip due to temporary faults. These faults are typically caused by vegetation, wildlife and unknown causes. Reclosers have the ability to clear these temporary faults, which can avoid the interruption altogether and improve overall network SAIDI and SAIFI.	0.85
MSU fault indicator units	We will install Fault Indicator Units on MSUs to reduce outages and outage durations, and ensure restoration is done safely and in as short a time as possible. We will improve network visibility by finding faulted equipment quicker, minimising the length of the network that is required to be patrolled and minimising the number of fault crews required to patrol the network after a fault has occurred.	1.25
Online dissolved gas analysis (DGA) monitoring for power transformers (new)	Online DGA monitoring provides continuous, real-time insight into the health of power transformers, which is critical for early detection of developing faults. Online monitoring detects real time trends and sudden changes in gas levels as they occur allowing operators to respond quickly, reducing the risk of catastrophic failures. Additionally, continuous data supports predictive analytics, helping to optimise maintenance schedules and improve reliability without relying solely on reactive measures.	0.55
Increasing communications resilience (continuing)	Our rural comms network currently consists mainly of low bandwidth radio links. With the increased requirement for interconnected comms to operate electrical networks reliably, safely, efficiently, and effectively, we will replace existing radio links with fibre. Our Operational Technology Fibre Strategy identifies a number of opportunities to install fibre in existing ducts, install new ducts with fibre, and replace existing radio links. The increased speed, bandwidth, and data capacity will lead to improved protection operation (safety), more reliable comms (as weather has no effect), enhanced security through CCTV camera installations at substations, and support for drone stations and drone surveillance/inspections, among other benefits.	5.89
Overhead lines remote control switches / network automation (continuing)	During an outage, we frequently switch the network to restore supply. We have a range of pole mounted switches that helps us do this; they comprise of comms enabled and manually operated switches. Manually operated switches require a service provider to be on site to operate them. Outages that involve manual switch operations, typically have a longer outage compared to a comms enabled one, which could be operated from the control centre or automatically switched through SCADA system. Our proposed programme is to retrofit comms on compatible equipment and replace some manually operated switches with new comms enabled versions. This will enable faster restoration and improved SAIDI performance.	1.24
Total		**9.78**

Our other RSE investments target specific safety improvements and environmental initiatives. These investments help ensure we maintain safe working conditions and meet our environmental commitments.

Table 12.5 Orion's other RSE investments ($m, FY26 constant)

Programme	Description	Capex
High impedance fault detection	Many of our rural feeders traverse areas that are at risk of wildfires. These rural feeders often fault, and while our protection and fuse systems may clear the majority of these faults, they may not be able to clear high impedance faults (HIF). This is because HIFs are typically low current, erratic and non-linear. Typical HIFs are caused by downed lines and/or arcing to highly resistive surfaces. HIFs, if undetected, could cause wildfires to ignite. We plan to install HIF detection systems to mitigate / prevent wildfires from igniting.	1.6
Zone substation fire risk remediations	Work to address identified fire risk at zone substations. Orion uses AS 2067:2016 as its standard for the design and construction of high voltage (>11kV) substations. An important aspect covered by this standard is minimum clearances for separation between transformers, other transformers and combustible buildings based on the quantity of oil in the transformer(s). Where minimum distances cannot be achieved, other mitigation measures, such as fire walls, should be employed. Orion has zone substations where AS 2067:2016 has been breached. Some of those substations have two transformers sharing an oil bund that should be segregated, as well as transformers too close to one another. There are also cases where there is insufficient space between transformers to install a fire wall, so the transformers potentially have to be re-located.	1.28
Zone substation buildings seismic remediations	Work to address identified fire risk at zone substations. Orion uses AS 2067:2016 as its standard for the design and construction of high voltage (>11kV) substations. An important aspect covered by this standard is minimum clearances for separation between transformers, other transformers and combustible buildings based on the quantity of oil in the transformer(s). Where minimum distances cannot be achieved, other mitigation measures, such as fire walls, should be employed. Orion has zone substations where AS 2067:2016 has been breached. Some of those substations have two transformers sharing an oil bund that should be segregated, as well as transformers too close to one another. There are also cases where there is insufficient space between transformers to install a fire wall, so the transformers potentially have to be re-located.	1.15
Earth potential rise issues	Earth Potential Rise (EPR) occurs when a fault current flows into the ground at a substation or other earthing point, causing the surrounding soil and structures to reach a significantly high voltage. This can create dangerous 'step and touch' voltages for personnel and pose risks to any members of the public near our towers. We have conducted some EPR tests on our tower assets which have identified touch voltages that exceed safe limits. Rectifying EPR issues is essential to comply with safety standards and protect both people and assets. Mitigation strategies, such as installing earth mats, new earthwires and installing barriers around our towers, will reduce EPR safety related risks.	2.0
Total		**6.03**

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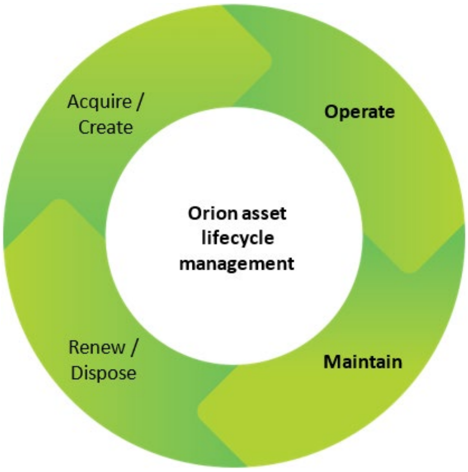
13. Operations and maintenance

13.1 Overview

As discussed in Section 6 – asset management system, we manage our network asset fleets using a lifecycle approach. The figure below shows the four lifecycle stages within our asset management approach.

Effective asset management relies on appropriate integration between operations and maintenance and the other lifecycle activities, including network development, design, procurement, construction, and renewal. Once commissioned, assets are put into service and the **Operate** and **Maintain** stages begin.

Figure 13.1 Asset lifecycle management



The Operate and Maintain stages last for an asset's full lifecycle and impact the timing and scope of other stages, e.g. the need for renewal. Our activities during the Operate and Maintain stages ensure the asset's safe and reliable performance over its expected life. Key activities include network operations (such as switching), maintenance, vegetation management, and spares management.

This section focuses on the Maintain stage of the asset lifecycle.

13.1.1 Our approach to maintenance

We undertake a range of maintenance activities to ensure our network assets operate in a safe and reliable manner throughout their lifetime. These activities include monitoring and managing the deterioration of assets and, in the event of a defect or failure, restoring service. Information gathered during maintenance activities is used to improve our asset standards and planning processes, and to inform our renewals programme.

Our lifecycle approach requires us to make trade-offs between maintaining our assets in service (opex) and replacing or refurbishing them (capex). For example, we may increase the frequency of maintenance for a particular asset type to increase asset life or defer renewal.

Key drivers of maintenance are:

- asset information collected to support cost-effective and prudent decisions
- legislative or regulatory requirements
- maintenance standards that specify inspection tasks and servicing intervals
- manufacturers' recommendations that set out specific tasks and servicing for certain assets
- asset defects and faults that lead to reactive maintenance or corrective maintenance.

The table below explains how effective maintenance is important in ensuring our asset management objectives are met.

Table 13.1 Asset management objectives relevant to maintenance

Asset management objectives	Maintenance
Safety *Reduce the potential for network assets to cause harm to people to So Far As Reasonably Practicable (SFARP) levels.*	The risk of exposing our staff, service delivery partners, and the public to injury, and our equipment to damage, will be reduced by our maintenance activities in accordance with our safety, maintenance, and operational standards.
Reliable Network *Improve (in localised areas) or maintain reliability as measured by System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).*	Reliability for customers can be improved by reducing unplanned outages. Our focus on preventive maintenance will assist in reducing unplanned outages in the longer term by informing our renewals programme. Rectifying outages in a timely way will support compliance with legislative or regulatory requirements.
Resilient Network *Strengthen the 4 Rs (Reduction, Readiness, Response, and Recovery) to minimise impact on customers following a High Impact Low Probability (HILP) event.*	Ensuring we can recover from events quickly supports the resilience of our services. This is increasingly important due to the growing impacts of climate-related incidents.
Operational Excellence *Enable safe, reliable, and cost-effective electricity services by developing our people, systems, and processes to optimise asset performance, cost, and risk.*	Our asset management will be supported by ensuring we have complete, accurate, and up to date data. Embedding learnings from trials (e.g. grid visibility tools, and advanced analytics) into standard operational processes to optimise maintenance.
Customers and Community *Enhance communication with customers and their experience when interacting with us.*	Planned interruptions to customers are minimised by coordinating proactive work with other works, prioritising works based on reliability risk, and coordinated works planning and engagement with councils, communities, and other utilities. Customers are notified prior to planned work being undertaken that will impact their supply. Landowner disruption is minimised when undertaking work. Safety and network risks associated with customer owned vegetation are minimised by working with customers.

13.1.1.1 Maintenance portfolios

We have defined three types of maintenance:

1. **Preventive maintenance**: scheduled work to ensure the continued safety and integrity of assets and to compile condition information for subsequent analysis and planning. This is our most regular asset intervention and a key source of information feedback for our asset management approaches.
2. **Corrective maintenance**: planned activities to address defects identified during preventive maintenance work. Where defects do not require urgent remediation, the work can be prioritised and scheduled, which is generally more cost effective than carrying it out reactively. Much of this work consists of small, remedial tasks.
3. **Reactive maintenance**: emergency and fault response and switching in response to an unplanned event or incident that impairs normal network operation. These activities manage hazardous or operational conditions that arise through network faults, manage the risk to our service delivery partners and the public, and restore supply to customers.

Our three maintenance portfolios are based on typical good electricity industry practice (GEIP) categories; preventive, corrective, and reactive, to reflect the way that we work. This means a shift from information disclosure-based categories. We explain how these categories align in their respective sections.

Our aim for the AMP period is to focus on preventive maintenance by improving and expanding our maintenance procedures, fully addressing inspection backlogs, leveraging integrated asset management (IAM) and AI capabilities, collecting more comprehensive asset data, and expanding our inspection regimes. In the short to medium term, we would expect an increase in inspections to also increase the required levels of corrective maintenance and renewal volumes, to a point.

13.1.2 Vegetation management

In addition to maintenance, this section discusses our approach to vegetation management. Vegetation management involves monitoring vegetation growing in close proximity to our assets, liaising with landowners, and trimming and removing vegetation to keep it clear of network assets, especially overhead lines. Vegetation management opex comprises the costs attributed to our vegetation contractors to undertake this work.

Vegetation can have a notable impact on network safety and reliability. Trees close to live conductors pose a risk of electrocution to our workforce, service delivery partners, and the public, together with a risk of fire in our local communities. Further, such events can result in significant damage to network equipment prompting network outages. Vegetation is one of the main influences on unplanned SAIDI and SAIFI performance.

13.1.3 Network opex forecasting approach

Consistent with our other opex categories, we use a ‘base-step-trend’ approach to forecasting. This approach is used by many utilities and economic regulators for forecasting recurring expenditure. It involves:

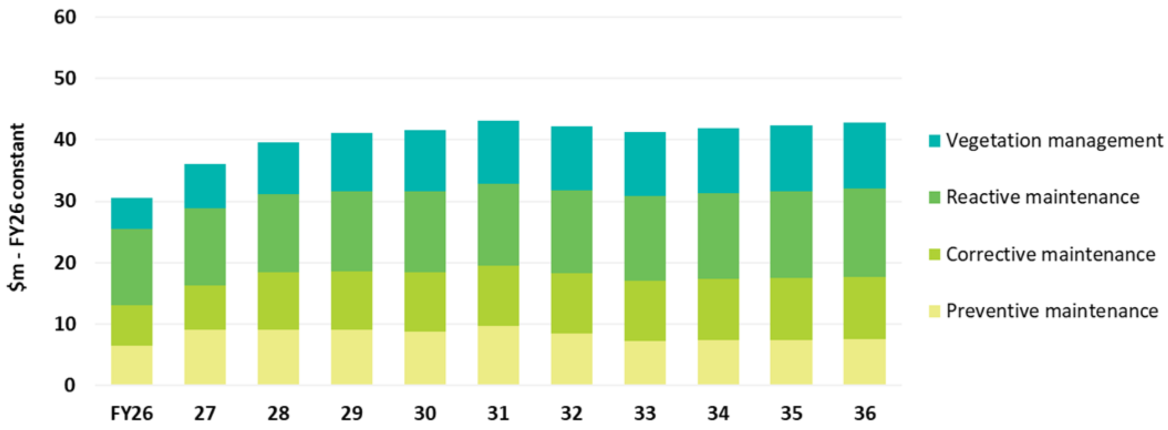
- **Base opex**: identifying ongoing activities and associated cost based on an efficient base year, which is projected forward.
- **Step changes**: required to meet network needs or external requirements. These can one-off or ongoing changes and involve a change in the scope of work delivered.
- **Trend changes**: that reflect expected changes in activity or costs due to output growth, e.g. network size.

In the sections below, we explain how the above components have been used to develop our network opex forecasts.

13.1.4 Total network opex forecast

Our network opex totals $412.3 million over the FY27-FY36 period. Figure 13.2 shows the total planned expenditure per annum.

Figure 13.2 Orion's planned total network opex per annum



Details on the forecast opex for each of the maintenance portfolios and vegetation management are set out in the sections below.

13.2 Preventive maintenance

13.2.1 Overview

Preventive maintenance includes scheduled work to ensure the continued safety and integrity of our assets. This work is our most regular asset intervention and a key source of information for our asset management system and wider work programmes.

Preventive maintenance influences our corrective maintenance and renewal activities. An increase in inspections would be expected, to a point, to inform required levels of corrective maintenance and renewal volumes in the short to medium term as we identify defects or potential risks during inspections. The main types of activities include:

- inspections of our network assets, including checks, patrols, and testing to confirm the safety and integrity of assets
- condition assessment of our network assets, including monitoring of asset condition to support renewal and corrective works
- servicing of our network assets, including regular maintenance tasks performed to maintain the condition of an asset.

These activities are typically carried out on a regular basis, e.g. every 5 years, in accordance with our maintenance standards.

Preventive maintenance expenditure is included within Information Disclosure item Routine and Corrective Maintenance and Inspection (RCI), as included in Schedule 11b in Appendix B.

Further details on our approach to maintenance, for our asset fleets, is set out in Appendix G – Network maintenance approaches.

13.2.2 Drivers

Our preventive maintenance programme helps maintain network reliability and manage safety risk. Failure to undertake sufficient preventive maintenance reduces our ability to make good industry practice asset management decisions, ultimately leading to increased whole of life costs. This may also lead to increased health and safety risks, for example, if we do not undertake the necessary inspections, we would not be able to identify which poles are unsafe to climb or are at imminent danger of failing.

In general, the amount of required preventive maintenance is driven by factors such as:

- **Asset information**: number of assets we need to inspect and compile data on condition, type, and performance to inform analysis and asset management decision-making.
- **Compliance**: meeting our legislative and regulatory requirements, including minimum frequencies for inspecting overhead conductor assets, certification of metering transformers,[50] and minimum electrical safe distances under NZECP 34:2001.
- **Maintenance standards**: our standards specify recommended maintenance inspections tasks, servicing intervals, and reporting requirements.
- **Manufacturer recommendations**: for inspections tasks and servicing intervals.

  Asset types: assets of different types, and from different manufacturers, will have a variety of characteristics. This impacts on the number of standards and manufacturer recommendations we need to follow.

13.2.3 Forecasting approach

Consistent with other opex categories, we use a 'base-step-trend' approach (see Section 13.1.3) to forecast preventive maintenance. For the forecasts in this AMP we have used FY25 as the base year, adopted several step changes as set out in the following table, and applied the DPP4 output trend.

Table 13.2 Summary of step changes

Step changes	Description
Overhead structures	
Pole inspections catchup	We have a backlog of pole inspections which are currently outside their 5-year inspection cycle. This step change is to catch up on our inspections and be within the 5-year cycle.
Telecoms company pole inspection	A telecoms company is intending to divest their poles to us, which have our equipment on them. We plan to inspect these poles, in alignment with our standard, before we take ownership of these assets.
Earth Potential Rise testing	Current injection and step touch potential tests for towers on public land and/or near residential properties or schools.
Overhead Conductors	
Conductor destructive testing	Performing destructive testing on parts of the conductor to confirm expected lives used in renewal forecasts. We also intend to use these to validate Cormon test results on our subtransmission lines.
Overhead survey and data improvement	Improving our data by undertaking a conductor verification survey to give us better confidence when developing and prioritising our conductor replacement programmes. There is scope to improve conductor type/material/size data.
Underground Cables	
Zone Substations	

[50] As required by the Electricity Governance Rules, and Health and Safety at Work (Asbestos) Regulations 2016.

Table 13.2 Summary of step changes

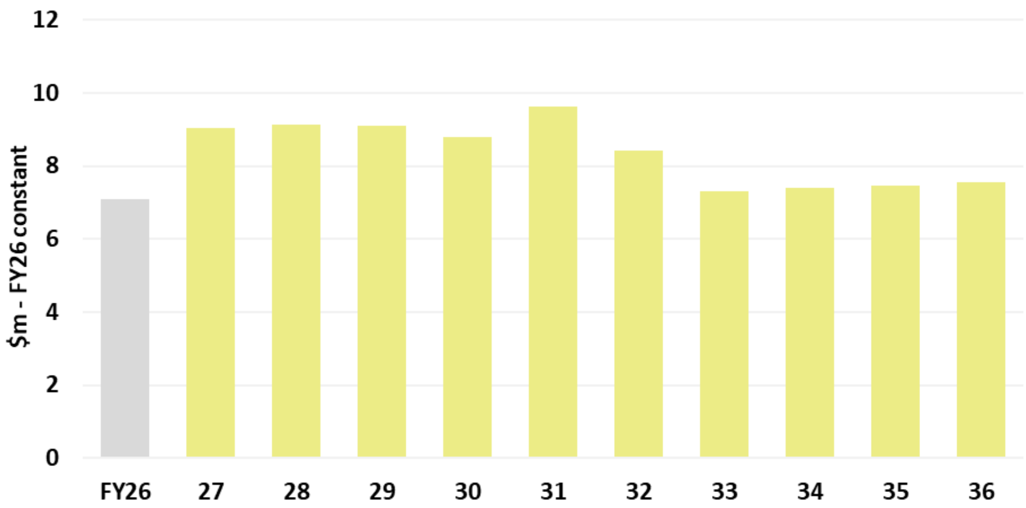
Step changes	Description
New Building Standard (NBS) assessments	Performing NBS assessments to determine the likely seismic performance of zone substation buildings on a cyclical basis to ensure alignment with any changes to the Building Code, reassessment following major modifications or additions, and evaluation of any deterioration over time.
Power transformer bund leak inspections	Ensuring the required bunded areas for each of our 85 power transformers is inspected for leaks.
Distribution Switchgear	
Distribution kiosks fire risk assessments	Many of our kiosks and distribution substations do not comply with AS2067 fire separation requirements. [51] We intend to undertake a programme of fire mitigation renewals. To inform and deliver this renewal activity, we will need to engage external fire engineering consultants to undertake fire risk assessments so we can prioritise mitigations based on risk.
Soil contamination testing	Soil contamination testing is critical for identifying and managing per- and poly- fluorinated alkyl substances and other hazardous substances in distribution substations. We aim to establish a recurring preventive maintenance programme that includes routine soil testing and the creation of a contamination register; similar to our asbestos management plan. Addressing contamination reactively during maintenance often leads to unexpected costs and delays. Proactive testing helps eliminate these surprises, highlights high-risk sites, and enables better planning with site specific plans and safer execution of future works.
NBS assessments	Performing NBS assessments to determine the likely seismic performance of distribution buildings on a cyclical basis to ensure alignment with any changes to the Building Code, reassessment following major modifications or additions, and evaluation of any deterioration over time.
Distribution Transformers	
Large ground mounted transformer inspections and testing	Introducing dissolved gas analysis for large ground mounted transformers to enable early detection of internal faults, helping to prevent costly failures and extend asset life.
Secondary Systems	
Signalling & comms cable condition assessment	Testing of copper pilot cables to assess condition to inform our renewal activity / replacements and ensure related asset data is complete, particularly around spare cable cores.
SCADA / RTUs – backlog of testing points and alarms	Increasing the number of intelligent electronic device (IED) points tested to include those monitoring relay/IED health. Currently these are only tested at commissioning.

[51] Our internal standard reflects the Australian standard covering fire separation requirements AS2067.

13.2.4 Forecast opex

The figure below shows an increase in opex during the CPP period as we improve and expand our maintenance procedures, fully address inspection backlogs, leverage IAM capabilities, and collect more comprehensive asset data, and expand our inspections regimes (as outlined in the section above). We expect to reach a steady state after the CPP period.

Figure 13.3 Planned preventive maintenance opex



Our total preventive maintenance opex requirement for the AMP period is approx. $83.9 million. Our planned additional preventive maintenance (step-changes) result in an uplift of expenditure from FY27, until we complete several programmes associated with the step changes. Reducing step change amounts beyond the CPP period are offset by the trend component of the forecast.

13.2.4.1 Expected benefits

The expected benefits of preventive maintenance work over the AMP period are:

- **Managing safety risk**: providing a safe network for our staff, service delivery partners, and members of the public reduces the risk of our workforce and the public being exposed to injury and reduces the risk of damage to the environment.
- **Ensuring reliability**: providing a reliable network for customers, while meeting agreed service levels.
- **Asset and condition information**: an uplift in inspections will provide us with improved condition information on which to make better informed asset management decisions. Preventive maintenance also provides a means to confirm asset characteristic or attribute information or gather it as required.
- **Cost-effective**: planned work is generally more cost effective compared to unplanned remediation work. Lifecycle costs should be reduced by undertaking an optimal volume of preventive work, supporting achievement of expected asset lives.
- **Improved decision-making**: by gathering better asset information, well-informed asset management decisions can be made to help reduce whole-of-life costs.
- **Support resilience**: ensuring we can identify resilience issues, e.g. if a distribution box has surface flooding this can help us to understand where localised flooding issues are. This is increasingly important due to the growing impacts of climate-related incidents.

13.3 Corrective maintenance

13.3.1 Overview

Corrective maintenance includes planned work undertaken by our service delivery partners to rectify defects and repair and replace minor components to restore assets to operational condition. Much of the work consists of small, remedial tasks. Where defects do not require urgent remediation, the work can be prioritised and scheduled, which is generally more cost effective than carrying it out reactively.

Defects are often identified during preventive maintenance (inspections, condition assessments, servicing, and testing), so an increase in preventive work may result in more corrective work for a period until the condition of the assets is acceptable. Reactive maintenance includes emergency response work which focuses on making assets safe and where possible, returning them to service promptly. Increases in incidents, such as due to adverse weather, may also increase the volume of corrective follow up work.

The main types of activities include:

- planned defect rectification
- planned repairs
- replacement of minor components to restore assets to operational condition.

Corrective maintenance expenditure is covered under Information Disclosure item Routine and Corrective Maintenance and Inspection (RCI) and Asset Replacement and Renewal (ARR) opex, and is included in Schedule 11b in Appendix B.

13.3.2 Drivers

Corrective maintenance drivers include addressing issues usually identified from preventive maintenance inspections and servicing, such as minor components of the crossarm assembly, replacement of guy wires, bolts, signs, and guards and maintenance of Magnefix Switching Unit terminations, which are prone to failure if exposed to dampness or contamination. These are scheduled in advance to ensure they are delivered cost-effectively. Failure to undertake this work would increase reliability and safety risks and may shorten asset lives.

In general, the amount of corrective maintenance volumes will be driven by factors such as:

- **Asset condition**: the volume of defects and replacement of minor components are expected to increase as the ages of our assets increase and condition deteriorates.
- **Fault numbers**: the number of faults can indicate where assets require non-urgent work.
- **Compliance**: meeting our legislative and regulatory requirements.
- **Other programmes**: an increase in preventive maintenance may result in more defects being identified.
- **Network incidents**: volumes of network incidents may influence required corrective work.

13.3.3 Forecasting approach

Consistent with other opex categories, we use a 'base-step-trend' approach to forecast corrective maintenance. In particular we have used FY25 as the base year, adopted several step changes as set out in the following table, and applied the DPP4 output trend.

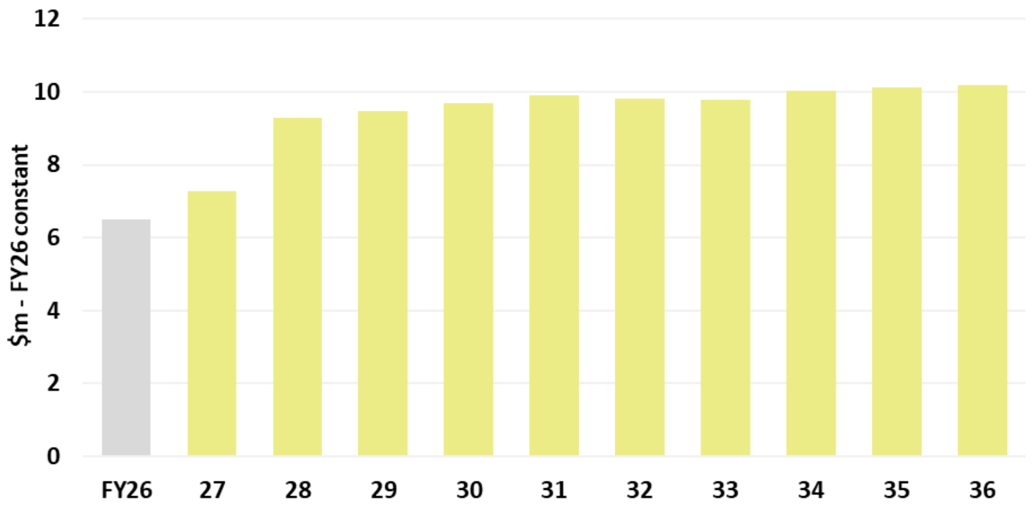
Table 13.3 Summary of step changes

Key step change examples	Description
Overhead Structures	
Overhead line defects	Addressing overhead line defects post construction and any backlog of midlife defects. The latter was previously deferred due to expenditure constraints.
Expected new defects	Following the increased focus on preventive maintenance, the number of new overhead structures defects requiring opex is expected to increase. We also expect the telecoms poles to be divested to us will be in relatively poor condition. Therefore, we reasonably expect more defects resulting from taking ownership of these poles.
Overhead Conductors	
Expected new defects	Resulting from increasing our condition assessments on our subtransmission overhead conductors.
Underground Cables	
Cable seals	Many of our ground mounted distribution substations have cable entries that are either unsealed or have deteriorated seals causing water ingress which contributes to equipment corrosion and corona discharge on cable terminations. This is a new programme to waterproof building cable entries over the AMP period.
Zone Substations	
Asbestos remediation	Removal and/or encapsulation of asbestos in zone substation buildings. This is a new programme over the AMP period.
Expected new defects	Resulting from increasing our buildings and grounds inspection frequency and a new programme of bund leak inspections.
Distribution Switchgear	
Asbestos remediation	Encapsulation of asbestos in our distribution buildings where asbestos is present.
Expected new defects	Resulting from increasing our buildings and grounds inspection frequency.

13.3.4 Forecast opex

The figure below shows our spend will be higher during the AMP period as our preventive maintenance initiatives include working through a backlog of inspections and assessments. As a result, we anticipate higher levels of defects being identified during the AMP period.

Figure 13.4 Planned corrective maintenance opex



Our total corrective maintenance opex requirement for the AMP period is approx. $95.5 million. Our expenditure has an upward trend at the start of the AMP period to ensure we efficiently address new defects, as these are identified through improved and expanded inspection regimes.

13.3.4.1 Expected benefits

The expected benefits of work over the AMP period are:

- **Managing safety risk**: providing a safe network for our staff, service delivery partners, and members of the public reduces the risk of our workforce and the public being exposed to injury and reduces the risk of damage to the environment.
- **Ensuring reliability**: providing a reliable network for customers, while meeting agreed service levels.
- **Cost-effective**: planned work is generally more cost effective compared to unplanned remediation work. Lifecycle costs can be reduced by undertaking corrective work rather than reactive work (post-failure).
- **Improved customer experience**: reducing the duration of unplanned outages will improve the network reliability experienced by customers.
- **Increased resilience**: ensuring we can recover from natural hazard events quickly will support the resilience of our network. This is increasingly important due to the growing impacts of climate-related incidents.

13.4 Reactive maintenance

13.4.1 Overview

Reactive maintenance includes interventions in response to unplanned network events that impact normal network operation. These events can lead to safety and/or reliability risks. This work is undertaken by our service delivery partners and is dispatched by the control room in response to network incidents or faults. Events that may require a reactive response include adverse weather, asset failure, vehicle or other third-party damage, and dispatched response to alarms. Weather has a significant impact on reactive maintenance volumes.

This work helps maintain network reliability and safety by managing hazardous or other operational conditions that arise through network faults, managing the risk to our service delivery partners and the public, and restoring supply to customers. The main types of activities include:

- **Emergency response**: which requires our service delivery partners to assess the impact of an event, such as a car hitting a pole or storm damage. Our service delivery partners are directed by the control room to undertake switching, or to isolate damaged network sections, or undertake other actions to make the site safe so supply can be restored.
- **Fault response**: to a network fault, such as an insulator or circuit breaker failing, is undertaken by our service delivery partners in a similar way to emergency response. Fault response also includes 'forced' outages of equipment in distress, where failure has not yet occurred but is imminent.

Reactive maintenance work can be challenging due to extreme weather or other severe conditions. Personnel must have a wide range of skills and competencies and need to be maintained across our network.

The expenditure in this portfolio reflects reactive maintenance works undertaken by our service delivery partners. Reactive maintenance expenditure is covered under Information Disclosure item Service Interruptions and Emergencies, and is included in Schedule 11b in Appendix B. The reactive maintenance portfolio directly aligns with this ID category.

13.4.2 Drivers

Our reactive maintenance programme helps maintain network reliability and safety.

A key driver of our expenditure is ensuring that we keep the impact of outages on customers to a minimum, while ensuring we meet our services standards and incident responses times. A need to have field crews on standby at strategic locations across our network is another key driver of required resources.

Service delivery partners attending a fault must have a wide range of skills and competencies to enable them to identify issues with certainty. Reactive maintenance work is often challenging due to extreme weather or other severe conditions.

In general, the amount of reactive maintenance volumes will be driven by factors such as:

- **Asset condition**: the volume of faults can be expected to increase as the ages of our assets increase and condition deteriorates.
- **Environmental conditions**: some assets, e.g. overhead assets, are more prone to failure in corrosive locations or in adverse weather, such as high winds. Snow and ice can also increase faults, due to additional structural loading on overhead lines. Snow, ice, and wind can also cause nearby vegetation to contact our assets, which can lead to faults. Climate-related change is increasing the frequency and severity of extreme weather events.
- **Third-party activities**: incidents such as car vs pole and cable strikes caused by third parties lead to outages and potential safety risks.

- **Other programmes**: the amount of work we undertake in other maintenance or renewal programmes impacts the amount of reactive maintenance volumes in the longer term. For example, an increase in planned renewal work on the overhead network will tend to decrease reactive maintenance volumes because it improves the condition of our assets. Similarly, an increase in corrective maintenance will also gradually reduce the amount of asset condition based reactive maintenance that is required in the longer term.
- **Asset types**: assets of different types, and from different manufacturers, will have a variety of characteristics. Some types fail more often than others, and some types are replaced upon failure, e.g. fuses, while others are replaced proactively.
- **Use of automation devices**: remote devices help reduce the impact of events, e.g. by remotely sectionalising the network, by speeding up restoration and reducing the impact on SAIDI.
- **Physical location**: rural and difficult to access areas require additional travel time to address faults.

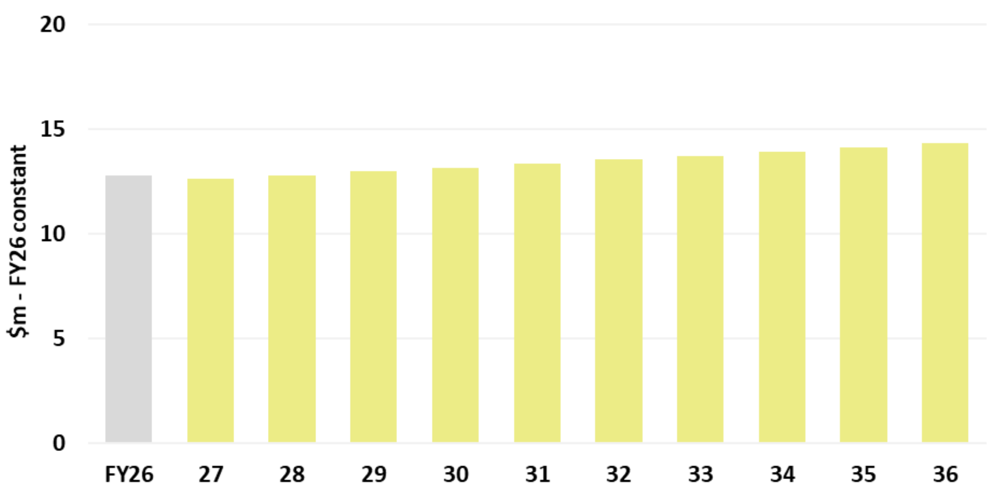
13.4.3 Forecasting approach

Consistent with other opex categories, we use a 'base-step-trend' (see Section 13.1.3) approach to forecast reactive maintenance. In particular we have used FY25 as the base year for reactive maintenance, not adopted any step changes, and applied the DPP4 output trend.

13.4.4 Forecast opex

The figure below shows a gradual increase in expenditure over the AMP period due to an expected increase in activity levels as a result of the growing network size – connections and network length growth. This trend is consistent with the approach used by the Commerce Commission to set DPP allowances.

Figure 13.5 Planned reactive maintenance opex



Total reactive maintenance opex requirement for the AMP period is approx. $134.4 million. Our expenditure has an upward trend due to the applied network growth factor. We have not added any step changes due to our expectation that the condition of our network will stabilise over time and therefore constrain the number of faults requiring reactive maintenance.

13.4.4.1 Expected benefits

The expected benefits of work over the AMP period are:

- **Managing safety risk**: providing a safe network for our staff, service delivery partners, and members of the public reduces the risk of anyone being exposed to risk of injury.
- **Ensuring reliability**: providing a reliable network for customers, while meeting agreed service levels.
- **Improved customer experience**: reducing the duration of unplanned outages will improve the network reliability experienced by customers.
- **Compliance**: timely rectification of outages supports our compliance with regulatory quality standards.
- **Greater resilience**: ensuring we can recover from events quickly supports the resilience of our services. This is increasingly important due to the growing impacts of climate-related incidents.

13.5 Vegetation management

13.5.1 Overview

Vegetation management includes the management of vegetation in proximity to the assets on our network, in particular overhead lines. For the purpose of this section, and descriptions in this document, ‘vegetation’ includes trees, shrubs, or plants, or any part of them.

This work helps maintain network reliability and safety by ensuring our assets are free from vegetation hazards that could present a safety risk or disrupt service to customers. Proactive management of vegetation is necessary for meeting our legislative responsibilities.

The main types of activities include:

- Cyclic inspection of our network to identify where vegetation encroaches or inhibits our access to equipment in order to operate them. Information is gathered from ground-based inspections. We use digital mapping tools, such as LiDAR, to identify volumes and types of vegetation that require attention.
- Future assessments of treefall hazards (both initial and ongoing), for trees within the distance specified by the Tree Regulations, by a qualified arborist in relation to likelihood and impact of a tree falling on lines.
- Planning preparation work, including access to sites, traffic management, planned outages, etc.
- Physical trimming and/or felling and removal of vegetation and debris, including cyclic LV and HV programmes, attending to service requests from customers.
- Managing traffic on public roads as required to trim or fell vegetation.
- Communicating with landowners, and occupiers where relevant, to outline responsibilities, arrange access to land, and issue relevant notices etc.

The large majority of the HV network sits within the rural areas of the Canterbury plains. These flat plain areas are dominated by working farms and lifestyle properties and are relatively unique in having large volumes of hedges and shelter belts acting as wind breaks to reduce strong winds from the southwest or nor-west winds which are generated from the Foehn effect of the Southern Alps.[52] These strong winds cause most of our vegetation related outages. The majority of the vegetation work for the HV network is related to hedges or shelter belts. This is often due to the planting of this vegetation directly underneath or directly beside our network.

[52] A Foehn wind is a hot and dry wind in the lee of a mountain range. Source: MetService.

To maintain the required clearance, specialist equipment is needed in the form of a shelter belt trimmer. These units have been developed for clearance of hedges and shelter belts with large cutting heads that require very experienced operators to maintain safety clearances and to manage the debris being cut from the large cutting blades. Maintaining hedges and shelter belts can also lead to an additional cost driver of higher traffic management costs.

13.5.2 Drivers

Our vegetation management programme helps maintain network reliability, resilience, and safety. A key driver of our expenditure is ensuring that we keep the impact of outages on customers to a minimum. Vegetation related faults are one of the main influences on unplanned SAIDI and SAIFI performance.

A large portion of faults relating to vegetation are caused by wind and snow, e.g. trees fall onto lines, broken branches blow into lines. Outages during Cyclone Gabrielle and Cyclone Tam were largely driven by vegetation, and it is expected that this impact will increase over time due to climate-related change.

Vegetation near power lines has the potential to cause significant safety risks, some of which may result in injury or death. The primary hazardous situation is direct vegetation contact, which can lead to a safety hazard by conducting electricity, causing a ‘step and touch’ potential. There are also safety risks associated with people climbing trees which are dangerously close to live assets. Additionally, safety and other risks arise due to wildfires started by vegetation coming into contact with the electricity network or as a result of flashovers.

In general, forecast vegetation management volumes will be driven by key assumptions such as:

- **Compliance**: meeting our requirements under the Tree Regulations, especially the recent and upcoming changes, will increase the volume of our work.
- **Physical location**: rural and difficult to access areas require additional travel time to address vegetation.
- **Out of zone**: historically vegetation that was outside the zones specified by the Tree Regulations had a large impact on network performance.

13.5.3 Tree Regulations

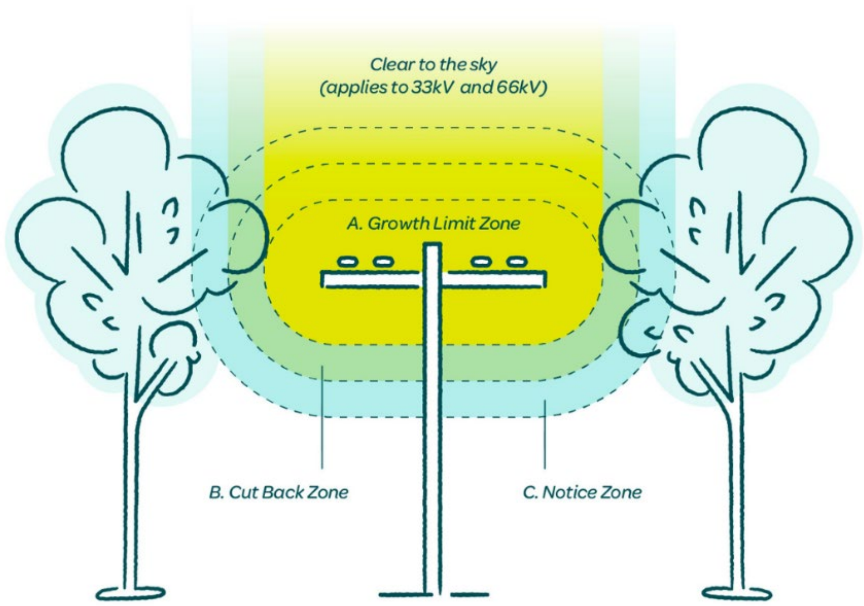
The Tree Regulations outline the obligations of electricity distribution businesses (EDBs) and landowners in relation to vegetation that is growing close to power lines, with the aim of keeping New Zealand’s electricity supply safe and secure.

The obligations of EDBs and land owners are centred around three zones, as set out below (and seen in the figure below):

1. **Growth Limit Zone**: a designated area around power lines where vegetation is not allowed to grow into, ensuring safe distances between vegetation and electrical infrastructure.
2. **Cut-Back Zone**: this zone extends one metre from the Growth Limit Zone. When vegetation is cleared, it is to be removed so that it does not enter this zone.
3. **Notice Zone**: this zone extends one metre from the Cut-Back Zone. If vegetation enters this zone, a hazard warning notice may be issued.

Where vegetation affects power lines, we may enforce the trimming of vegetation. Orion is responsible for the first cut of trees near power lines. We have met this obligation by completing a first cut of vegetation on all our lines.

Figure 13.6 Clearance zones



13.5.4 Forecasting approach

Consistent with other opex categories, we use a 'base-step-trend' approach to forecast vegetation management. In particular we have used FY25 as the base year for vegetation management, adopted step changes as set out in the following table, and applied the DPP4 output trend. Our step change forecasts assume that the signalled amendments to the Electricity (Hazards from Trees) Regulations 2003, including the extension of 'clear to sky' requirements and the introduction of treefall hazard risk assessment obligations, will be gazetted in FY27. This assumption drives the timing and quantum of the step changes; if the amendments are delayed or modified, actual expenditure requirements may differ.

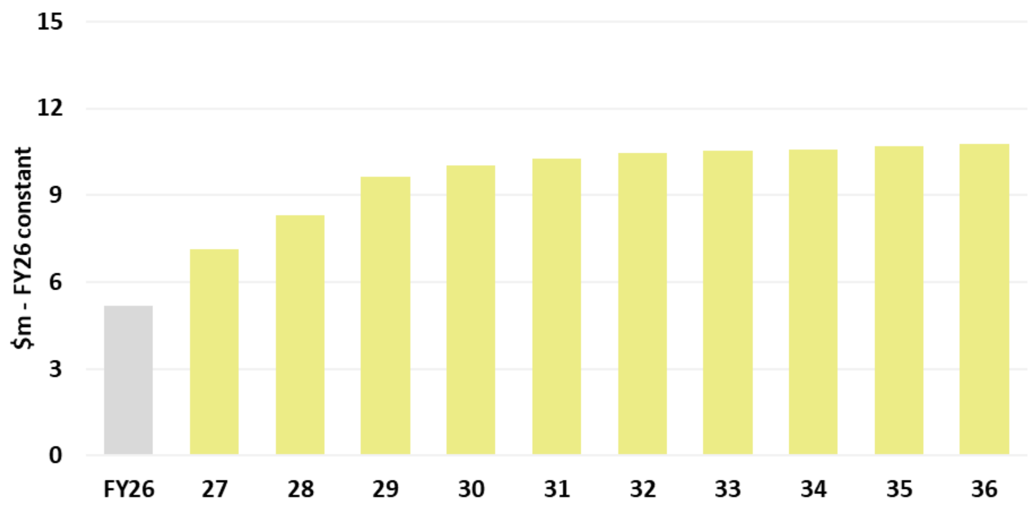
Table 13.4 Summary of step changes

Step change	Description
'Clear to sky' requirements	Included to meet expected changes to 'clear to sky' requirements.
Treefall hazard risk assessments	Included to meet expected introduction of treefall hazard risk assessments for certain vegetation. We will also need to continually assess vegetation as it grows to the height requirements for assessment.
Removal of treefall hazard risks	Vegetation that is assessed as being of moderate or high treefall hazard risk must be removed. This step change is in preparation for that work.

13.5.5 Forecast opex

The figure below shows an increase in expenditure from FY27 to comply with the incoming legislative requirements. We expect to reach a steady state after five to six years.

Figure 13.7 Planned vegetation management opex



Our total vegetation management opex requirement for the AMP period is approx. $98.4 million. Step changes have been added to reflect expected costs of extended 'clear to sky' requirements, undertaking initial and ongoing hazard risk assessments for fall distance vegetation, and trimming or removing vegetation that was assessed as moderate or high treefall hazard risk.

13.5.5.1 Expected benefits

The expected benefits of work over the AMP period are:

- **Greater resilience**: ensuring we are more resilient to natural hazard events, i.e. high winds and heavy snow, will support the overall resilience of our network. This is increasingly important due to the growing number of volatile climate-related incidents.
- **Compliance:** our planned work programme will ensure we comply with expected changes to the Tree Regulations.
- **Managing safety risk**: providing a safe network for our staff, service delivery partners, and members of the public reduces the risk of anyone being exposed to injury and reduces the risk of damage to the environment and our equipment.
- **Reduced fire risk**: removing vegetation near our network can result in a lower likelihood of vegetation-related fires.
- **Improved customer experience**: reducing the number of unplanned faults and failures on the overhead network due to vegetation will improve the network reliability experienced by customers.

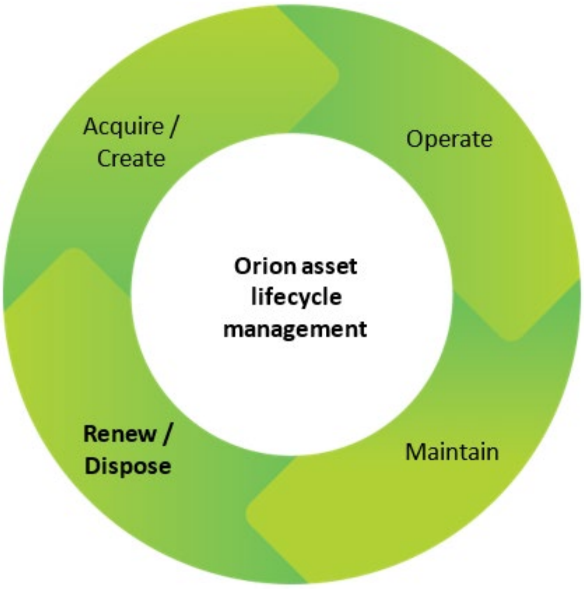
14

14. Asset renewal

14.1 Overview

As noted in Section 13 – Operations and maintenance, effective asset management relies on a holistic approach that considers the full asset lifecycle, as outlined in the figure below.

Figure 14.1 Asset lifecycle management



This section focuses on the Renew/Dispose stage of the asset lifecycle.

14.2 Asset renewal and disposal

Asset renewal is the replacement of aging, damaged, poor condition, or under-performing assets with like-for-like or new modern equivalents.[53] Asset renewal also includes refurbishment of existing assets to extend their useful life or increase their service potential, which is (generally) capitalised.

Disposal follows the decision to remove an asset from our network, either because it is being replaced or has become redundant.

14.2.1 Renewal drivers

As assets deteriorate, they eventually reach a state where ongoing maintenance to keep them safe and serviceable becomes ineffective or uneconomic. Refurbishment and replacement are key activities to manage asset condition, safety risk and network performance, resilience, obsolescence, and to meet regulatory and legislative requirements. Actual renewal drivers will vary by asset fleet.

[53] Non-capitalised replacements are included under our corrective maintenance portfolio.

Table 14.1 Key renewal drivers

Renewal Driver	Description
Asset condition / Asset health	Asset health reflects the expected remaining life of an asset and serves as a proxy for the likelihood of failure. Assets assessed as being in poor health are deemed to have an increased risk of failure, leading to additional reliability and safety risks. For longer-term forecasts, we use various forecasting approaches to estimate future asset health. For most assets, the decision on the individual assets to replace is driven by actual condition information gathered from the field.
Safety risk	Poor condition assets can fail leading to risks to our workers, the public, and our service delivery partners. A key driver for many renewal investments is mitigating the risk that poor condition assets pose and reducing hazards as much as reasonably practicable.[54]
Environmental risk	We have a duty to our community to meet environmental statutory compliance. Some assets, e.g. those containing oil, pose environmental risks that require mitigation. Compliance requirements may drive trigger investments like bunding and containment systems.
Reliability	Renewals manage customer reliability levels by replacing poor condition assets and addressing known failure modes. Some asset types or models fail prematurely and require targeted replacement.
Resilience	Our network assets need to cost-effectively withstand extreme events like storms and earthquakes. Older assets built to lower historical standards may need upgrading where risk is deemed unacceptable.
Obsolescence	Assets become obsolete when incompatible with modern systems and standards, when spares or manufacturer support are unavailable, or when maintenance expertise is lost. Obsolescence often drives renewal of secondary systems where modern replacements provide better functionality, performance, and network control.

14.2.1.1 Asset health

For longer-term forecasts, we typically forecast replacement quantities on a volumetric basis using various forecasting approaches to ascertain future asset health.

We use several modelling approaches, with a range of data inputs including age and condition, to calculate the Asset Health Index (AHI) for individual assets. The AHI categories are set out in the figure below.

Figure 14.2 Orion's asset health index scores and category descriptions

AH Score	Category Description	Replacement Period
H1	Asset has reached the end of its useful life	Within one year
H2	Material failure risk, short-term replacement	Between 1 and 3 years
H3	Increasing failure risk, medium-term replacement	Between 3 and 10 years
H4	Normal deterioration, monitor regularly	Between 10 and 20 years
H5	As new condition, insignificant failure risk	Over 20 years

Based on asset health forecasts, we can estimate the required future volume of asset interventions for our asset fleets, e.g. forecast renewal investments will reflect expected H1 volumes. We can then consider

[54] We aim to have no condition-based unassisted failures resulting in injuries to the public, our workers, or service delivery partners. Unassisted failures are functional failures caused by deteriorating asset performance / condition over the life of the asset. For example, an asset failing due to degrading condition (cracking, corrosion, insulation degradation) or environmental factors such as storms of a magnitude the asset was designed to withstand. Assisted failures are functional failures that are caused by an external factor that was outside the design standards of the equipment, as specified by us at the time of construction.

trade-offs between different fleets based on constraints, such as pricing, assisted by the use of asset criticality, in order to finalise our planning.

14.2.2 Disposals

We dispose of used assets in a manner appropriate to their type. We consider options such as reusing, recycling, selling as scrap, on selling for non-commercial purposes, or disposing of in landfill. Metal materials are disposed of through members of the Scrap Metal Recycling Association of New Zealand (SMRANZ).

Some asset fleets have specific requirements, as follows:

- **Poles**: recycling of poles for appropriate use cases is our preferred outcome, e.g. in non-structural community projects such as playgrounds and mountain bike tracks.
- **Subtransmission cables**: our process is planned to minimise environmental impact and recover as much value as possible. When we replace our oil-filled cables, we plan to follow a decommissioning procedure based on current industry best practice. We anticipate that this will include vacuum removal of oil and capping of the cable so that it may be safely left in place in a deenergised state. For cables that are not oil-filled and are installed in ducts, we remove and recycle them to recover metals; remaining materials are safely disposed of. Where direct buried, non-oil-filled cables are generally capped and left in situ.
- **Outdoor and indoor switchgear**: 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).
- **Zone substation buildings**: historically, we have sold old substation buildings when they are no longer needed. Prior to disposal of land, we undertake due diligence investigations on environmental and property matters, as appropriate. We have guidelines and a management plan for the disposal of asbestos and our substation design standards mandate risk assessment for works in and around potentially contaminated land, requiring the use of qualified personnel for advice on disposal options. Disposal requirements and options for all excavation-related work are set out in a network specification.
- **Batteries and DC supplies**: our direct current (DC) supply systems rely (mostly) on lead-acid batteries. Sulphuric acid and lead are hazardous, in terms of safety and the environment. Lead-acid batteries are completely recyclable, and environment risks associated with their hazardous substances can be mitigated by appropriate recycling.

14.2.3 Asset classes

To support our asset management approach, we have defined seven asset classes which form the basis of our day-to-day asset intervention strategies:

- overhead structures
- overhead conductors
- underground cables
- zone substations
- distribution switchgear
- distribution transformers
- secondary systems.

For each asset class we have taken a consistent approach to providing a summary of the role of the assets in our network and the asset fleets that make up that asset class.

For each asset fleet we provide an asset overview, asset population and age, asset health, asset performance and risk, renewal strategy, and renewal forecasting approach.

14.2.3.1 Asset class strategies

The role of asset class strategies is to describe the assets within each class, including their characteristics, e.g. age profiles and condition, together with risk levels, typical interventions, and strategies throughout their lifecycles.

Key components of the strategies from a planning perspective include levels of service for the asset class, investment approaches, asset information, and continuous improvement.

The asset class groupings set out in the section above reflect the way we manage these assets and plan our investments. The asset class strategies focus on each of our asset classes.

14.2.3.2 Network capex forecasting structure

Our AMP renewal forecasts cover a 10-year planning horizon. They include high value projects, e.g. zone substation renewals, and volume-based forecasts, such as poles, crossarms, and conductors (termed 'volumetric' forecasting). Longer term volumetric forecasts are delivered as individual projects or programmes based on defined triggers, such as poor condition. Asset health and criticality are important inputs into our decision-making.

The table below sets out the hierarchy of our asset classes and fleets, together with our fleet forecasting methods. Further details on our forecasting methods and resulting forecasts are covered in the following sections.

Table 14.2 Asset fleet forecasting methods

Asset classes	Asset fleets	Forecasting method	Key drivers
Overhead structures	Poles	Survivor analysis (hardwood and concrete poles) Repex (softwood and steel poles) Number of identified poles (poles vulnerable to wildfire)	Reliability, resilience (wildfire), condition, and safety
	Crossarms	Repex	Reliability, condition, and safety
	Steel structures	Condition based Number of bare grillage-type foundations	Reliability and condition
Overhead conductors	Subtransmission conductors	Individual projects (poor condition and LiDAR identified clearance violations). Repex (minor works) – corrosion zone, type, and size based	Reliability, safety, environment, and condition
	Distribution conductors	Repex – corrosion zone, type, and size based	Reliability and safety
	Low voltage conductors	Repex - corrosion zone, type, and size based	Reliability and safety
Underground cables	Subtransmission cables	Identified projects (all oil-filled cables) Repex (other capital works)	Condition, environment, and reliability
	Distribution cables	Repex	Condition, performance, and reliability

Table 14.2 Asset fleet forecasting methods

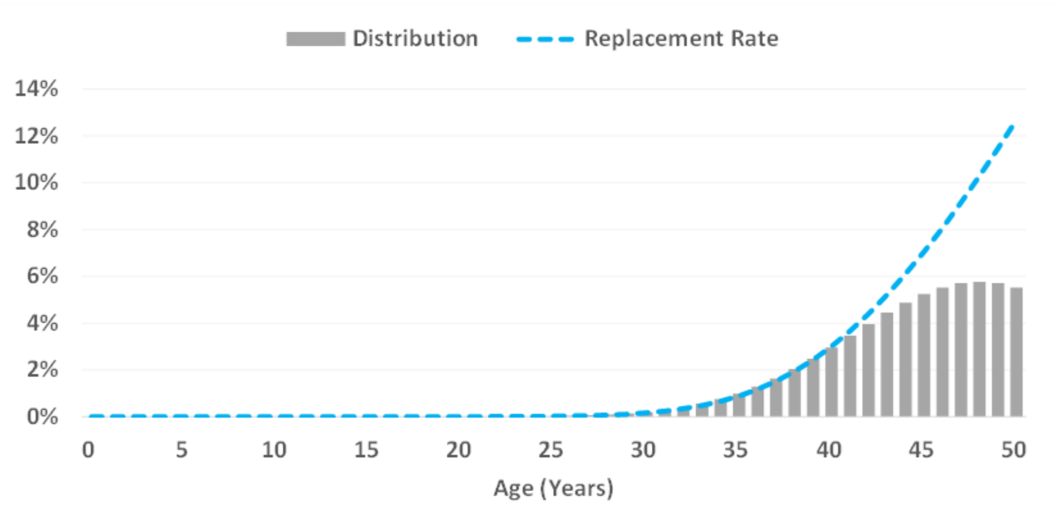
Asset classes	Asset fleets	Forecasting method	Key drivers
		Overhead to underground conversions based on identified issues, e.g. under-clearances	
	Low voltage cables	Repex	Reliability
Zone substations	Power transformers	Probability of failure and economic models	Reliability, condition, and environment
	Outdoor switchgear	Probability of failure and economic models	Reliability, safety, and condition
	Indoor switchgear	Probability of failure and economic models	Safety, reliability, and condition
	Ancillary equipment	Age	Reliability
	Buildings and grounds	Base-trend (minor building works)	Safety and seismic performance
Distribution switchgear	Poles mounted switchgear	Repex	Safety and reliability
	Pole mounted fuses	Repex Trending	Safety and resilience (wildfire)
	Ground mounted switchgear	Repex Number of units in service – type issues	Safety, type-issue, reliability, and condition
	Enclosures	Repex Number of distribution substation buildings under 50% and 70% of the New Building Standard for Importance Level 3 Number of enclosures affected by overhead to underground conversions	Safety, reliability, and condition
	Ancillary equipment	Base-step-trend	Reliability and safety
Distribution transformers	Ground mounted transformers	Repex	Reliability and condition
	Pole mounted transformers	Repex	Reliability and condition
	Voltage regulators and capacitors	Repex	Reliability and condition
	Generators	Age-based	Condition
Secondary systems	Protection	Age based	Type and condition
	Signalling/communication cables	Repex	Type and condition
	Supervisory control and data acquisition (SCADA) (remote terminal units or RTUs)	Age-based	Condition
	Communications	Age-based	Condition
	Batteries and DC supplies	Age-based	Condition
	Metering	Age-based	Condition

The Repex, or Replacement Expenditure, approach to forecasting renewals referred to in the table above is used by many utilities and economic regulators for assessing and forecasting renewals expenditure.[55] The Repex approach involves:

- determining a distribution of the age at which replacement is required (using a normal distribution)[56] for each type of asset, with the mean being the life-expectancy of the asset and the standard deviation being the square root of the life-expectancy
- applying the resulting probabilistic replacement rate curve to the current asset population to predict the future number of replacements.

The use of a Repex distribution means that statistically not all of the assets will require replacement at their stated end of expected life, as would be anticipated, due to details that are impractical to gather and model. This is a better reflection of which assets will require replacement than an age-based model, and a smoother and more deliverable replacement profile is generated.

Figure 14.3 Example of a distribution and replacement rate



We use a volumetric approach to cost estimation multiplying the quantity of replacements by the unit rate. The unit rate will depend on the type of asset. These models specify a volume of expected discoveries of poor condition assets, while inspection results will then trigger the actual investments.

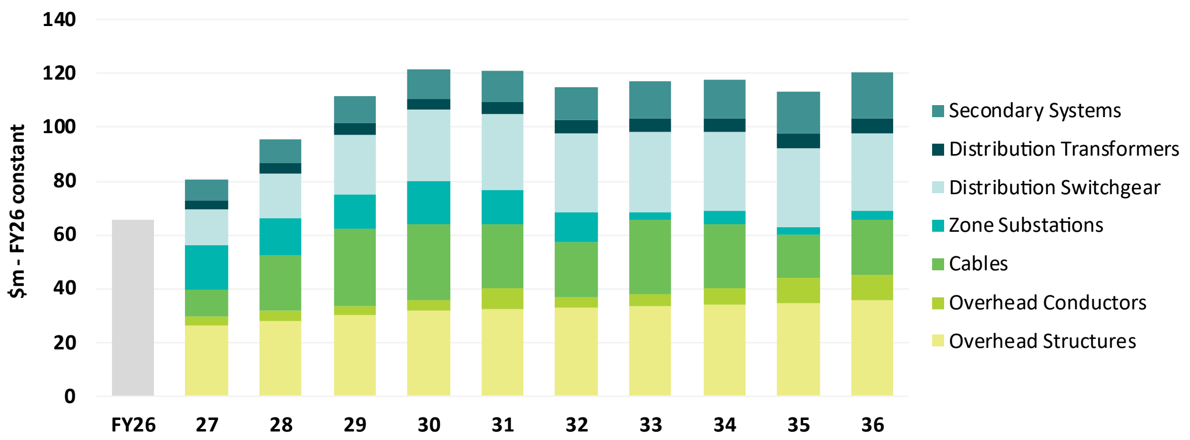
[55] The Repex approach is used by energy network businesses regulated by the Australian Energy Regulator and previous CPPs in New Zealand.

[56] Normal distribution was used for these assets as opposed to a Weibull distribution. We have done this because the normal distribution is less conservative in terms of estimating volumes of end of life assets as the standard deviation of the distribution is typically larger than that of an equivalent Weibull.

14.2.4 Investment overview

Our asset renewals investment totals $1.1 billion over the FY27-FY36 period. Figure 14.4 shows the total planned investment per annum.

Figure 14.4 Orion's planned total asset renewals capex per annum



Details on the forecast capex for each of the individual asset classes are set out in the sections below.

14.2.5 Asset management objectives

The table below explains how effective asset renewals are important to ensure our asset management objectives are met.

Table 14.3 Asset management objectives relevant to asset renewal

Asset management objectives	Asset renewal	Asset class objectives
Safety *Reduce the potential for network assets to cause harm to people to So Far As Reasonably Practicable (SFARP) levels.*	The risk of exposing our staff, service delivery partners, and the public to injury, and our equipment to damage, will be reduced by our renewals activities in accordance with our safety and maintenance standards. Ensuring safety is embedded throughout asset design, construction, operation, and decommissioning.	No condition-based unassisted failures resulting in injuries to the public, our workers, or service delivery partners. No condition-based unassisted failures resulting in damage to property. Proactively replace or manage assets that present safety hazards e.g. arc flash risks, legacy switchgear, unsafe pole foundations.
Reliable Network *Improve (in localised areas) or maintain reliability, as measured by SAIDI and SAIFI.*	Reliability for customers will be improved by reducing unplanned outages. Planned work is generally more cost effective and less inconvenient for landowners and customers. Rectifying outages in a timely way will support compliance with legislative or regulatory requirements. Focus lifecycle investment on renewal of deteriorating assets, particularly where failures could impact reliability metrics.	Unplanned outages and supply interruptions to customers are minimised. Design standards are kept current and a robust network is constructed to perform to the design lifecycle, with consideration of the impacts of climate change. Asset life is maximised and the incidence and impact of failures and defects reduced by prioritising maintenance and renewal work.
Resilient Network *Strengthen the 4 Rs (Reduction, Readiness, Response, and Recovery)*	Ensuring we can recover from events quickly supports the resilience of our services. This is increasingly important	Alternative technologies and materials are implemented to improve resilience to extreme events.

Table 14.3 Asset management objectives relevant to asset renewal

Asset management objectives	Asset renewal	Asset class objectives
to minimise impact on customers following a High Impact Low Probability event.	due to the growing impacts of climate-related incidents.	The resilience of our overhead structure assets to withstand and recover from extreme weather events and natural disasters is enhanced. Prioritise renewal of assets exposed to rare but high-impact events, e.g. severe weather, flooding, earthquakes. Focus investment on hardening vulnerable parts of the network, including replacing legacy subtransmission cables, strengthening structures, and relocating or redesigning exposed assets.
Operational Excellence *Enable safe, reliable, and cost-effective electricity services by developing our people, systems, and processes to optimise asset performance, cost, and risk.*	Our asset management will be improved by ensuring we have complete, accurate, and up to date data.	Fleet performance and condition is monitored to identify type issues and ageing trends; these insights are used to support targeted interventions, ensure appropriate network spares, and optimise lifecycle costs. Condition assessments and data collection processes are refined to reduce manual effort, ensure data is complete, and enable more cost-effective decisions around asset health, risk, and maintenance/renewal planning.
Customers and Community *Enhance communication with customers, and their experience when interacting with us.*	Planned interruptions to customers are minimised by coordinating proactive work with other works, and prioritising works based on reliability risk. Customers are notified prior to planned work being undertaken that will impact their supply. Landowner disruption is minimised when undertaking work. Safety and network risks associated with customer vegetation are minimised by working with customers.	Planned interruptions to customers are minimised by coordinating proactive structure work with other works, and prioritising works based on reliability risk. Customers are notified prior to planned work being undertaken that will impact their supply. Landowner disruption is minimised when undertaking work. Safety and network risks associated with customer owned vegetation are minimised by working with customers.
Environmental Sustainability *Facilitate reduction in polluting consumables or emissions, either for us or the community.*	Improve end of life asset disposal and recycling practices to reduce waste to landfill and mitigate environmental impacts.	Environmental impact is considered and minimised throughout the lifecycle of assets. Prioritise materials and designs that reduce embodied and operational emissions, e.g. lower-carbon concrete, recycled poles, SF_6-free switchgear.

14.2.6 Maintenance approaches

Our approach to maintenance for each of the asset fleets is set out in Appendix G – Network maintenance approaches.

14.3 Overhead structures

The role of overhead structures is to support our overhead conductors. Overhead structures are essential to moving electricity around our network. This section outlines the asset fleets that make up our overhead structures asset class:

- poles
- crossarms (including pole-top hardware)
- steel structures (including foundations).

14.3.1 Poles

14.3.1.1 Asset overview

Our poles fleet is made up of three types:

- **Timber (hardwood and softwood)**: generally preferred over other types based on cost and weight considerations, though they can be susceptible to decay. Hardwood poles are stronger and more durable than softwood, but softwood poles have the advantages of being lighter, locally sourced, and less costly, though they are more susceptible to decay and have a shorter life.
- **Concrete (mass reinforced and pre-stressed)**: mass reinforced poles are durable but heavy; they have steel reinforcing only, so lack the tensile strength of pre-stressed poles. We no longer install these poles. Pre-stressed poles are manufactured using concrete mix set around pre-stressed steel, making them stronger and more durable. We rarely install them today, with their use limited to very specific locations where a timber pole cannot meet the design or performance requirements.
- **Steel**: we have fewer than 100 steel poles on our network. These are only used where needed for site specific strength and height requirements. We do not use them more widely because of their higher cost.

Some poles do not carry conductors but serve as strain or stub poles which provide tensioning support**.**

14.3.1.2 Asset population and age

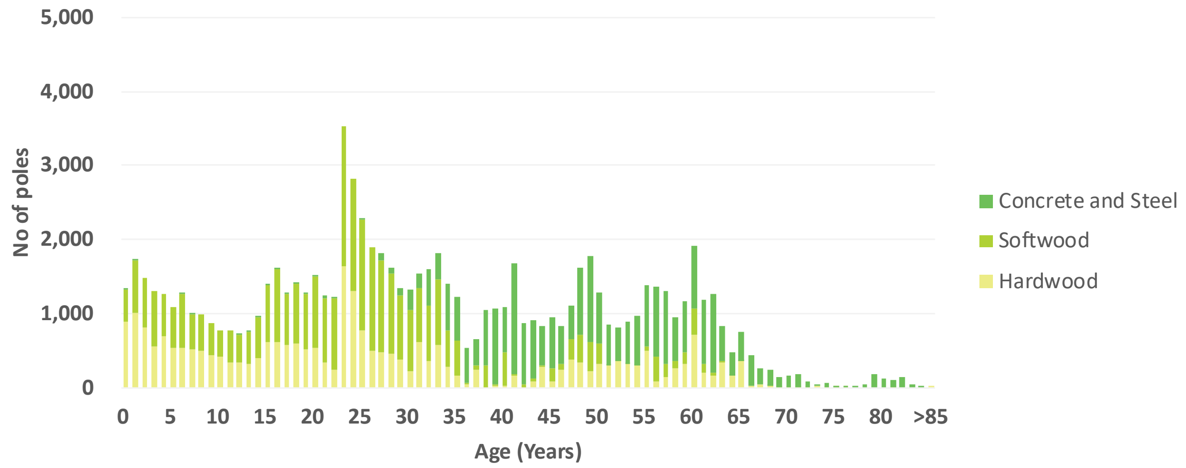
The table below summarises our population of poles by type. In addition, our overhead assets utilise a number of poles, mostly softwood, owned by a telecoms company for which we are the sole user. These are not included in the table below. It is likely that there will be future management of those poles by Orion as the telecoms company no longer uses the poles and is likely to divest them in the medium term.

Table 14.4 Population – poles

Asset type	Population (approx.)
Hardwood	27,300
Softwood	32,300
Concrete and steel	26,600
Total	**86,200**

The figure on the following page shows the age profile of our poles fleet across all voltages. Concrete poles were widely used until about 30 years ago, since then nearly all poles installed have been timber. Our oldest concrete poles are nearing the end of their expected lives. A substantial number of timber poles have already exceeded their expected lives.

Figure 14.5 Age profiles - poles



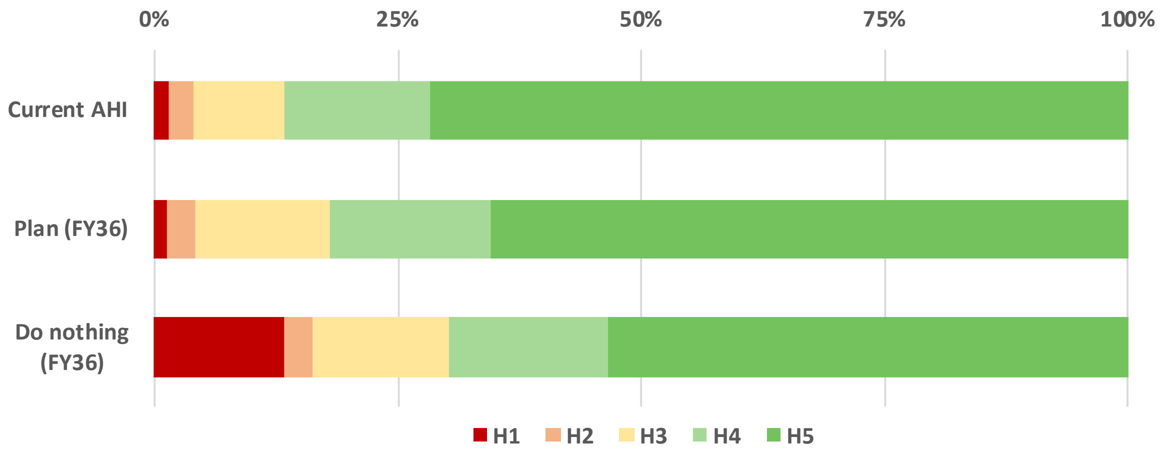
There is an age spike at approx. 25 years of age. At this time Telstra Clear (Saturn) was rolling out its fibre-optic cable programme and needed to install cables on Orion's poles. The fibre-optic cable increased the loading and height/size requirements on the poles, requiring many poles to be replaced during the rollout.

14.3.1.3 Asset health

We estimate the asset health of our hardwood and concrete poles primarily on their expected 'survivorship'. This is built up using a survivor curve which utilises historical failure data. The curve represents the proportion of poles that have failed (due to poor condition etc) by a particular age.

For our softwood and steel poles we have adopted an age-based Repex approach to derive future asset health, as we have less historical data for these assets. Our AHI for these poles reflects expected remaining life. The figure below sets out an overview of the asset health scores for our poles fleet.

Figure 14.6 Asset health – poles



A portion of our timber poles are nearing their end of life (represented by the H1-H3 portions of the figure above). These comprise many poles (H1 portion) that are in poor condition and will generally be replaced within 12 months.

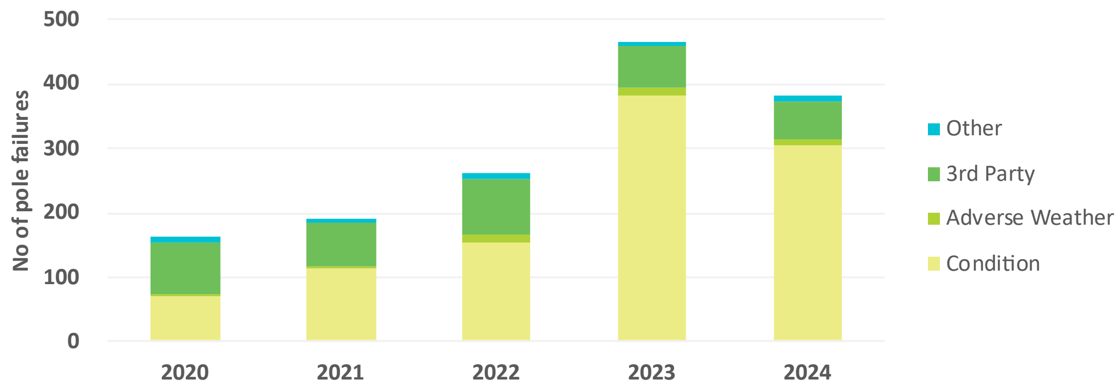
Our concrete and steel poles are generally in good health. They are usually longer lived than timber poles and we do not envisage these will pose material risk during the AMP period.

14.3.1.4 Asset performance and risk

Support structures, by their inherent nature, can create risks to public and worker safety. We install poles with the strength to handle defined environmental conditions, such as wind and snow loadings on conductors, but failures may still occur. We have a number of poles that are located in high wildfire risk areas, warranting replacement with a fire-resistant pole.

The performance of this fleet is measured by monitoring the number and type of pole failures, as shown in the figure below.

Figure 14.7 Performance - number of pole failures



The figure above shows that a large proportion of failures are related to condition. This type of failure includes all poles tagged as red and orange (refer to Appendix G for condition assessment scoring). Third party failures are mostly caused by car accidents.

In FY22 we changed our inspection / condition assessment to include below ground inspections. This led to a greater number of poles being rated as red or orange tags which drove the trend upwards from FY22-FY24. We are yet to complete below ground inspections for all of our poles, as we have not completed a full cycle of inspections since this change was introduced. For FY25, we currently have a backlog of poles that are outside their 5-year inspection cycle, so have not included FY25 in the figure above.

The table below summarises the key risks we have identified for our poles.

Table 14.5 Identified risks and mitigations – poles

Risk Areas	Description	Mitigations
Health and safety Network interruption	Timber poles lose strength over time due to decay, including pole top rot, localised decay pockets and knots, and cracking Concrete poles can lose strength if cracking/spalling allows moisture ingress	Design to AS/NZS7000-2016 standard. Including deterioration allowances Regular inspections, coupled with renewals to maintain asset health
Health and safety Network interruption	Timber poles – ground conditions can contribute to timber decay reducing strength Insect damage can weaken timber poles	Design in accordance with AS/NZ7000-2016 Maintenance inspection and replacement programme
Health and safety Network interruption	Third-party civil works may undermine poles foundations, or third parties may damage poles due to impact from vehicles Deliberately lit fires	Reflective markers are attached to all roadside poles in rural areas A consent is required to work within 4m of overhead power lines Signage and advertising to raise awareness

Table 14.5 Identified risks and mitigations – poles		
Risk Areas	**Description**	**Mitigations**
Network interruption	Landslips, caused by heavy rain, undermining poles can cause them to lean	Refinement of design standards
Network interruption	Poles burned during wildfires prevent us reinstating supply	Wildfire risk poles programme to replace timber poles with alternatives in high wildfire risk areas Refinement of design standards
Health and safety Network interruption	Vegetation strike - trees coming into contact with overhead assets can damage poles and pole-top assets and lead to faults. This could also heighten the risk of electrocution for anyone touching the assets	Vegetation control work programme to meet the Electricity (Hazards from Trees) Regulations 2003 Public information campaign around tree management

14.3.1.5 Renewal strategy

Our preventive maintenance inspections and condition assessments identify poles that are nearing end of life and establish the timing for renewal. This renewal programme accounts for most of our pole replacements. We prioritise the replacement of end of life poles located in high criticality locations, such as near a school or in the CBD. Customer impact may also be considered.

As we have low tolerance for pole failures, we replace red and orange tagged poles as quickly as practicable (immediately and within 3 months, respectively). In all cases the full crossarm assembly is replaced as part of the pole replacement.

In addition to our condition-based renewal works, we have a programme to replace several thousand poles that are vulnerable to wildfire. These poles are located in high wildfire risk areas, warranting replacement with a fire-resistant pole. These interventions will be prioritised based on risk and consequence.

As mentioned above, we expect telecoms poles to be progressively transferred to Orion and all poles will be inspected against Orion's standard before transfer. Based on inspections to date, we expect a substantial portion will require renewal. Replacement of these poles forms the basis of the planned telecoms pole programme and ensures assets entering our fleet meet Orion's safety and reliability standards.

Table 14.6 Renewal strategy – poles	
Tasks	**Description**
Renewal trigger	Condition / defect. Poles vulnerable to wildfire. Reactive replacements due to third party damage – mainly car vs pole. Reactive replacements due to extreme weather events or damage from vegetation.
Forecasting approach	We forecast proactive renewal volumes of poles using: • Survivor analysis (hardwood and concrete poles) • Repex (softwood and steel poles) • Poles vulnerable to wildfire: number of identified poles
Cost estimation	Volumetric

We do not refurbish poles, also known as pole reinforcing or nailing, which involves installing a steel truss around wood poles that have below ground rot. This approach is not feasible for our network due to concerns around their performance in seismic and liquefaction conditions. The Canterbury region is classified as a high seismic risk area, due to the Greendale fault and most of the region is susceptible to liquefaction. Our preferred approach is to replace wood poles that have below ground rot, which delivers a more robust and enduring solution.

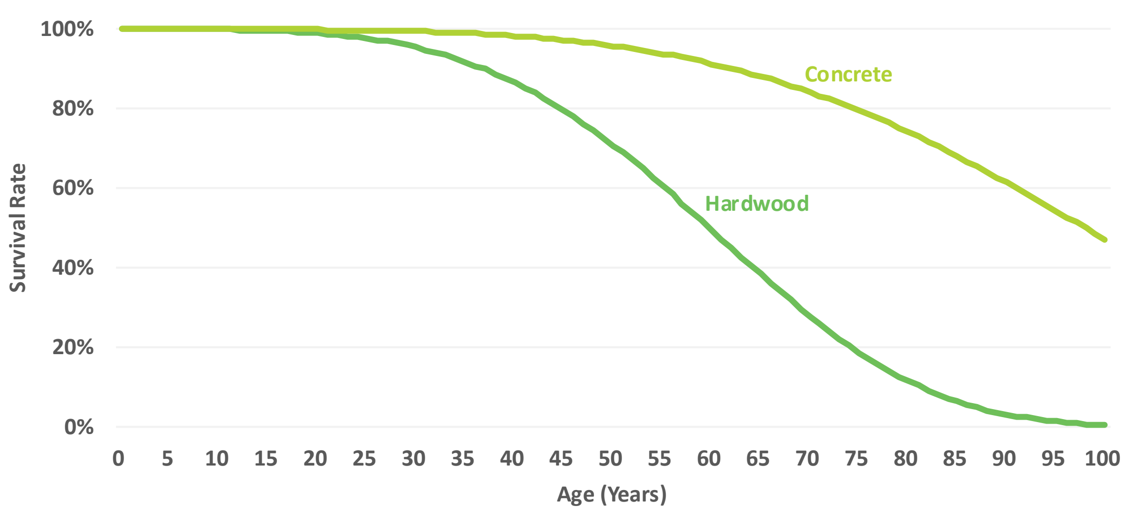
14.3.1.6 Renewal forecasting approach

We have adopted the following renewal forecasting approaches for our poles:

Hardwood and concrete poles (survivor analysis)

A survivor analysis uses information from previous end of life asset replacements to build a probabilistic replacement rate curve, which produces a likelihood of failure for an asset of a given age. A survivor analysis-based forecast is preferred over an age-based model as it recognises that some assets have longer or shorter than average lives due to factors such as location. Unlike an age-based model, it produces a smooth replacement rate while reflecting the age profile of the fleet. The figure below shows the survivor curves for our hardwood and concrete poles.

Figure 14.8 Survivor curves for hardwood and concrete



The survivor curves indicate the percentage of population remaining at a given age. The P50 survival age is approx. 60 and 100 years for our hardwood and concrete poles, respectively. Poles replaced due to system growth, relocations, customer-driven requests, and reconducting projects are excluded.

Softwood and steel poles (Repex approach)

We use the Repex approach for softwood and steel poles. We have assumed:

- 45 years expected life for softwood poles. The replacement age is determined from a weighted average of past renewals
- 75 years expected life for steel poles
- the age of steel poles, as the population is small in relation to the overall population.

We use a volumetric approach to cost estimation, for both the Repex and survivor curve approaches, multiplying the forecast number of replacements by the unit rate. The unit rates for general and telecommunications poles are based on recent historical average costs and provide for replacing the crossarm assembly as part of the pole replacement.

Telecommunications poles (survivor analysis and Repex approach)

Most telecoms poles are softwood, with small proportions of hardwood, concrete, and steel. Consistent with general pole renewals, we applied survivor analysis to hardwood and concrete poles and Repex modelling to softwood and steel poles.

Wildfire risk poles (location)

We identified locations within our network that have a high risk of wildfire, then analysed the quantity of poles in those locations. Our forecast reflects the quantities of poles identified as needing mitigation from wildfire.

14.3.2 Crossarms

14.3.2.1 Asset overview

Our crossarms fleet is made up of a variety of types and configurations due to different equipment suppliers, historical line designs, and line voltage levels. Crossarms are mainly hardwood, with a very small number of steel. This fleet also includes insulators and other components, such as bolts, binders, braces, and jumpers.

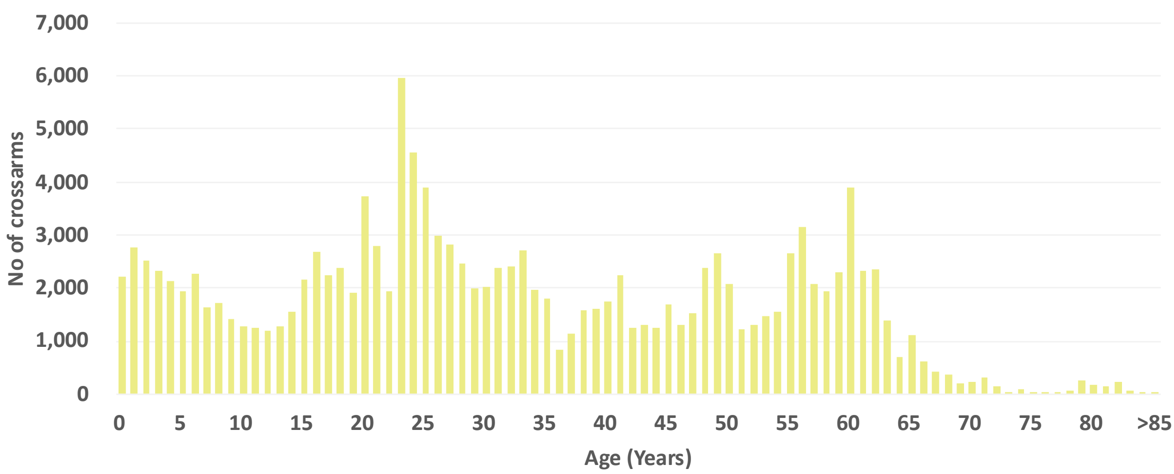
14.3.2.2 Asset population and age

Historically, we have not treated crossarms as a separate asset in our asset management systems. As a result, there is scope to improve our population and age data. We have plans underway to address this and have begun collecting more detailed crossarm information whenever a pole visit, such as an inspection, is made. With our implementation of Maximo we can record all individual crossarms as separate assets, from which point we can backfill crossarm age and type data whenever a pole is visited.

Until such time as this work is completed, we have estimated the crossarms population and age profile to support planning. Our estimates are based on the number of circuits on each pole. For example, if a pole has three circuits on it, we have assumed there are three crossarms. The poles owned by the telecoms company generally have one or no crossarms, as they are in the low voltage network.

We have approximately 143,000 crossarms in total. The figure below shows the age profile of our crossarms fleet.

Figure 14.9 Age profiles - crossarms



Crossarms generally have a shorter life than that of the poles, so most poles with timber crossarms will require one or more crossarm renewals during their life. Insulators and other components generally have a longer life than the timber crossarm but are typically renewed when crossarms are being replaced as this approach is cost effective.

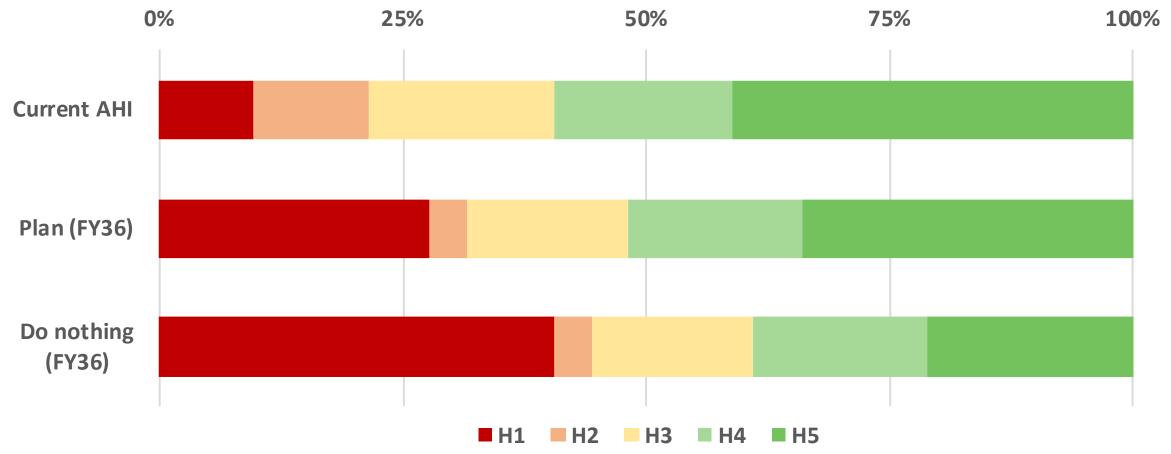
A significant volume of new crossarms were installed approx. 25 years ago. These correspond to the poles that were replaced as part of the fibre optic cable rollout by Telstra Clear (Saturn). Crossarms were also replaced due to condition, increased loading, and size/height requirements. Many crossarms have exceeded their expected life of 45 years.

14.3.2.3 Asset health

We have adopted an age-based Repex approach to derive the future asset health of our crossarms fleet. Our AHI for crossarms reflects expected remaining life. The life expectancy of crossarms is represented by a distribution as this approach is more robust than simply assuming that equipment fails at a particular age.

The figure below sets out an overview of the asset health scores of our crossarms fleet.

Figure 14.10 Asset health – crossarms



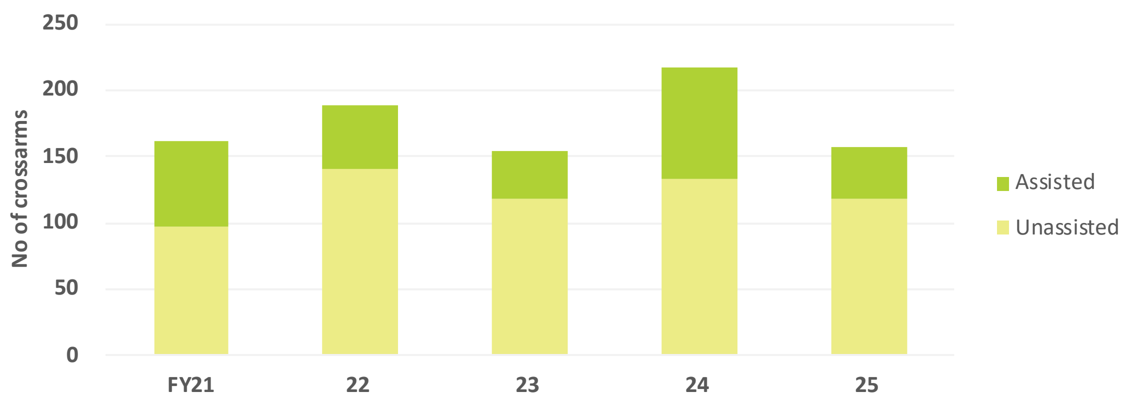
Some of our crossarms are at end of life (classified as H1) at FY26, primarily due to the aged nature of the crossarm fleet. We are expecting a large number of the fleet will need replacement over the next 10 years (represented by the H1-H3 portions of the figure above). Our planned investments will begin the process of improving our overall crossarms fleet health over the AMP period, helping to manage the risks associated with crossarms failures. Given that a considerable number of crossarms have exceeded their expected life, our level of H1 crossarms will remain higher than desirable. However, as we develop and implement our renewal prioritisation by risk/criticality, we expect the residual risk to be relatively low.

14.3.2.4 Asset performance and risk

Crossarms can create risks to public and worker safety. For example, a crossarm failure can result in a conductor falling which, in turn, could result in electrocution or fire risk to people, property, or livestock, either directly or indirectly by livening houses, fences, or other structures. Failures that occur in circumstances outside the design parameters are known as 'assisted' failures, while those that occur within design parameters are 'unassisted'.

The performance of this fleet is measured by monitoring the number and type of failures, as shown in the figure below.

Figure 14.11 Performance - number of assisted / unassisted crossarm failures



The figure above shows the number of assisted and unassisted crossarm failures over the past five years. Performance appears relatively stable. The types of failure are consistent with failure data for poles, where most failures were due to condition, with a lesser number caused by third party activity.

The table on the following page summarises the key risks we have identified for our crossarms.

Table 14.7 Identified risks and mitigations – crossarms

Risk Area	Description	Mitigations
Network interruption	Wooden crossarms may fail due to decay/rot. Hardware – binders fatigue, and insulators can fail over time. Insulators on wooden crossarms may loosen due to vibration-induced wear, timber shrinkage, or timber decay.	Consider new materials. Regular inspections as part of pole inspection regime, supplemented by drone inspections. Reinstating the full overhead line defects programme. Ramp up renewals programme to maintain health.
Network interruption	Intense vibrations from laminar flow wind and strong weather can cause fatigue and wear on hardware.	Refinement of design standards. Use of dampeners
Network interruption	Crossarms burned during wildfires prevent us reinstating supply.	Wildfire risk poles programme to replace timber poles with alternatives in high wildfire risk areas will also replace associated crossarm assemblies.
Network interruption Health and safety	Vegetation strike - trees coming into contact with pole-top equipment can cause damage to the equipment and/or faults. This could also heighten the risk of electrocution for anyone touching the equipment.	Vegetation control work programme to meet the Electricity (Hazards from Trees) Regulations 2003. Public information campaign.

14.3.2.5 Renewal strategy

Crossarm failures may result in conductors falling to the ground, which is a significant public and worker safety risk. Poor condition crossarms pose a higher risk in areas with fire risk or with higher population density, e.g. beside a school. We will also consider reliability performance, e.g. based on worst performing feeders, to prioritise work programmes.

In FY26 we initiated a dedicated, proactive, crossarm replacement programme based on 'as found' crossarm condition, as identified during pole inspection surveys. Our initial focus is on old crossarms with pin-type insulators. Replacements are prioritised based on reliability performance, location, and criticality.

The full crossarm assembly is replaced when a pole is replaced and those crossarm renewals are included in the poles forecast.

Table 14.8 Renewal strategy – crossarms

Tasks	Description
Renewal trigger	Condition / defect Failure Reactive works following weather events or damage from vegetation
Forecasting approach	We forecast proactive renewal volumes of crossarms using Repex
Cost estimation	Volumetric

14.3.2.6 Renewal forecasting approach

Our crossarm renewal forecasting approach is based on volumetric price times quantity. We have adopted a Repex approach to forecast crossarm renewal quantities, with an expected life of 45 years. Our crossarm unit rate is based on an estimated average cost covering a wide range of brownfield conditions. The unit rate provides for replacing full crossarm assemblies.

14.3.3 Steel structures

14.3.3.1 Asset overview

Our steel structures fleet is made up of different types of galvanised steel lattice towers. A tower asset includes the tower body and legs, and its foundations. The fleet also includes insulators and attachments for overhead conductors carried on the structures.

There are four different types of foundation: (1) direct buried steel grillage, (2) concrete encased steel grillage, (3) anchor bolt/base plate, and (4) concrete stub leg. Foundation type is a driver as only direct buried steel grillages require intervention at this stage.

14.3.3.2 Asset population and age

Most of our towers are at least 50 years old and need routine inspection and maintenance and proactive refurbishment to keep them in good serviceable condition. Many of the towers are located within residential or commercial suburbs around Christchurch.

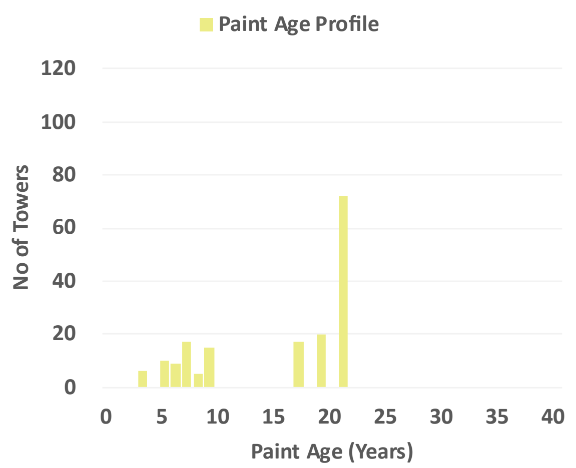
The table below summarises our population of steel structures by management type.

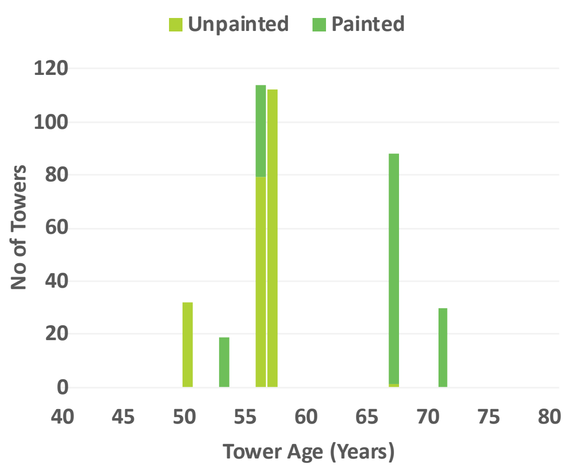
Table 14.9 Population – steel structures

Management approach	Population (approx.)
Painted	171
Unpainted	224
Total	**395**

The figure below show the age profile of our towers fleet (right), and the paint age for towers that have been painted (left). Depending on the corrosion zone, the paint is expected to protect the steel for 12-20 years, at which point recoating is required. Over half of our towers are unpainted, and of those that have been painted, many are overdue for recoating. Towers with a paint age above 15 years are already overdue for painting, the rest will be due for painting in the next 10 years.

Figure 14.12 Age profiles – paint age (left) vs towers age (right)

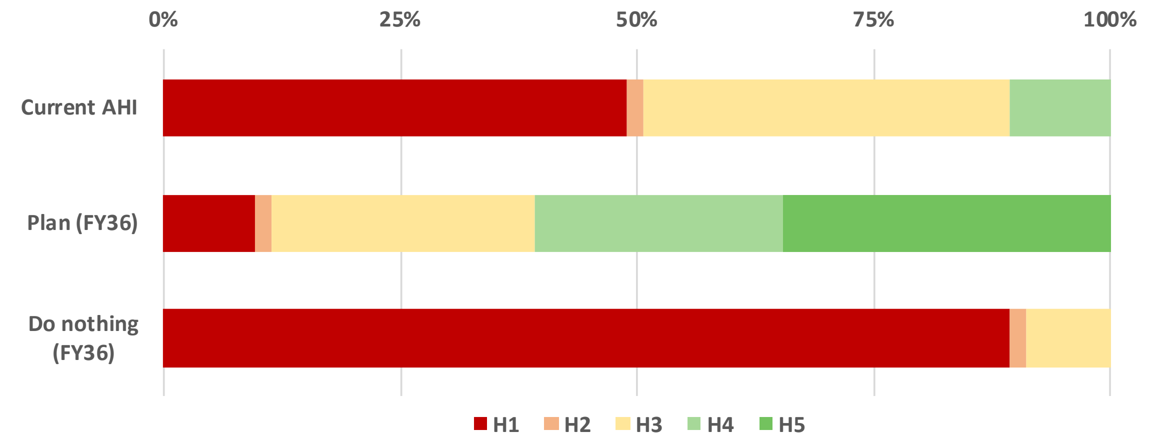




14.3.3.3 Asset health

The figure below sets out an overview of the asset health scores for our towers fleet.

Figure 14.13 Asset health – steel structures



The main cause of degradation is corrosion, driven by the corrosiveness of the area in which they are located and their age, i.e. how long they have been exposed. We generally manage corrosion by painting tower steel with a thick coating.

We determine the actions to be taken to address the health of individual towers, excluding the foundations, based on a condition degradation algorithm. It considers the following factors:

- Current condition assessment score for the tower, as a whole and for its various parts
- Corrosion zone in which the tower is located – ranging from extreme to benign – and associated degradation curve.

Many of our towers are already painted, however many of these are now due or overdue for their re-coating cycle. Our latest condition assessments also indicate many of our unpainted towers are due for remediation. Further delaying remediations, i.e. painting, steel replacement or converting them to steel monopoles, until severe corrosion has occurred will increase the risk of tower failure. This increases both public and worker safety risks as well as reliability risks. Our planned remediations over the AMP period aims to improve our overall asset health, reducing H1 levels down significantly and helping to manage the overall failure risk of the steel structures fleet.

14.3.3.4 Asset performance and risk

Tower failures can cause a significant outage as they tend to carry double circuit 66 kV lines and have the potential to cause significant harm or property damage. The possible consequences of a tower collapse include fire on public or private land, electric shock, physical damage to people and property, and loss of power supply.

None of our steel structures have failed in the past. However, given the age profile information above on the paint age of our towers, there is an increased risk of towers failing.

The table below summarises the key risks we have identified for our steel structures.

Table 14.10 Identified risks and mitigations – steel structures

Risk Area	Description	Mitigations
Network interruption	Tower steel loss of cross-sectional area due to corrosion. Corrosion of direct steel buried grillage foundations.	Tower inspections and condition assessments. Refurbishments and renewals, including replacing steel, painting the towers, and encasing grillage foundations in concrete.

Table 14.10 Identified risks and mitigations – steel structures		
Risk Area	**Description**	**Mitigations**
Health and safety	Electric shock 'step and touch' potential if a fault occurs when a person walks nearby or is touching the tower. This risk is greater in extreme weather and for towers located in high public use areas or near houses.	Testing towers for earth potential rise risk. Apply appropriate mitigation measures for any towers identified as having an unacceptable societal impact.

14.3.3.5 Renewal strategy

As towers are maintained in perpetuity to the extent possible, we rely heavily on refurbishment programmes to manage asset condition:

- **Tower painting programme**: painting towers protects good steel before any issues arise, then we maintain the coating systems to optimise this protection. In general, the first paint is undertaken at 35-50 years from new, depending on the corrosion zone, and a repaint approx. 15-20 years later, depending on condition and location.
- **Tower foundation refurbishment programme**: this involves encasing existing grillage foundations in concrete. It is a one-off remediation and once completed, only the above ground interfaces will require ongoing attention.
- **Steel replacement**: in this programme, we replace degraded steel parts of towers if the condition assessment score falls to CA30. Steel replacement is our primary tool to manage the condition of towers in locations where painting is not feasible, such as due to space congestion or where we cannot blast clean the old surface.

For management of our tower assets, we divide the Canterbury region into corrosion zones. Generally, the further we move inland, the less corrosive the environment, although industrial areas are more corrosive than non-industrial areas. We inspect towers and undertake a detailed condition assessment of them every five years, scheduling them for painting, or replacing degraded steel and bolts as needed.

In addition to the refurbishment options, we also consider replacement of small towers with steel monopoles where this is cost effective. We may also do this in specific situations, such as river crossings, or where additional height is required to meet NZECP34 clearance requirements.

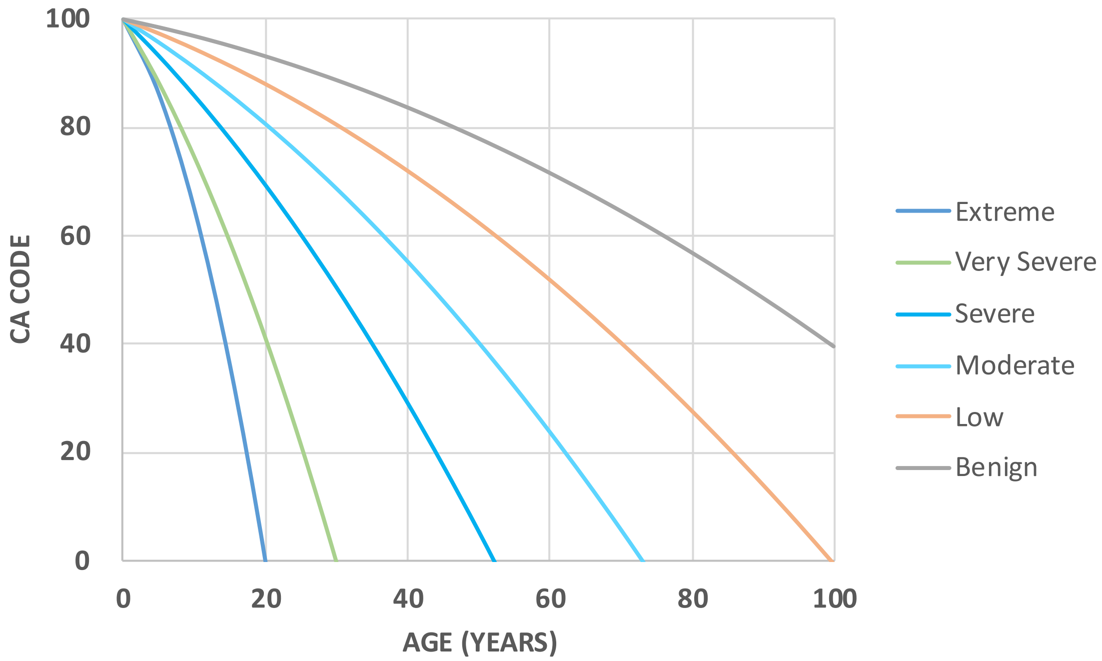
Table 14.11 Renewal strategy – steel structures	
Tasks	**Description**
Renewal trigger	Tower, steel, or paint condition Foundation condition Clearance violations
Forecasting approach	We forecast proactive renewal volumes of steel structures using: • Individual assessment • Number of bare grillage-type foundations
Cost estimation	Volumetric

14.3.3.6 Renewal forecasting approach

We use a volumetric approach to cost estimation multiplying the quantities determined based on condition by relevant unit rates. Forecasting volumes involves:

- Our five-yearly condition assessments producing a condition score for each tower, based on the condition of the upper and lower body of the tower
- Each tower being assigned to a corrosion zone depending on its location.

Figure 14.14 Tower steel degradation rates by corrosion zone



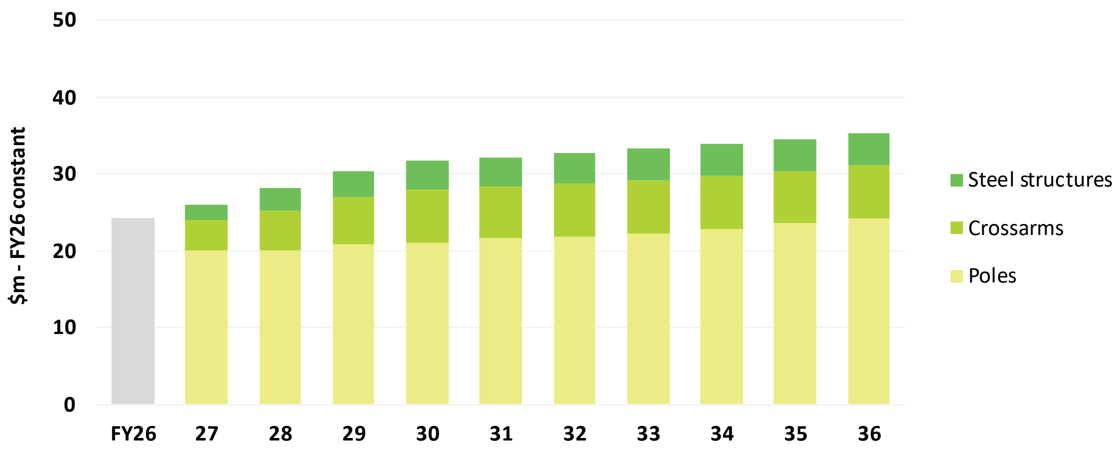
We condition assess towers in alignment with industry standards. A condition assessment score of 100 means the tower is new and in good condition. If, for example, we assess a tower at CA 60 for a moderate corrosion zone, we then forecast when that tower will reach its intervention point given that it's in a 'moderate' corrosion zone. In this case that is CA 30, which is approximately 20 years from the inspection date.

Characteristics of specific towers may make them ineligible for painting, or eligible for replacement with monopoles. If the tower is in a restricted area, we replace degraded steel, rather than painting it. Where a small tower is due for painting, we may replace it with a monopole, as it may be more cost effective to do this than painting. This also avoids the ongoing need to recoat. We are progressively encasing all grillage foundations in concrete.

14.3.4 Overhead structures forecast capex

The following figure shows our forecast capex for overhead structures.

Figure 14.15 Planned overhead structures renewals capex



During the AMP period, investment in overhead structures will be a total of approx. $318.4 million.

Our overall poles renewal capex increases gradually over the AMP period, reflecting an expected reduction in renewing poor condition poles offset by increased investment in telecommunication poles following ownership transfer, and a greater focus on mitigating wildfire risk. Crossarm investment will increase gradually, stabilising from FY30 onwards as we address the backlog of end-of-life crossarms. Investment in steel structures, which includes tower painting, steel replacements and conversions, will also gradually increase over the AMP period. This increase reflects the volume of overdue refurbishment work; the programme aims to address the backlog by the end of the AMP period.

14.4 Overhead conductor

The role of overhead conductor is to move electricity around our network. This section outlines the asset fleets that make up our overhead conductor asset class:

- subtransmission conductor (33 kV and 66 kV)
- distribution conductor (11 kV)
- low voltage conductor (400 V).

14.4.1 Subtransmission conductor

14.4.1.1 Asset overview

Our subtransmission overhead conductor distribute electricity from Transpower's grid exit points (GXPs) to, and between, our zone substations at 66 kV and 33 kV voltages. These are highly critical assets which must be reliable, secure, and resilient. All 33 kV conductor is carried on poles, while 66 kV conductor is carried on either poles or steel towers.

Our subtransmission conductor fleet is made up of two types:

1. **Hand drawn (HD) copper:** this stranded copper conductor are used on some of our older 33 kV subtransmission lines.
2. **Aluminium conductor steel-reinforced (ACSR):** this stranded aluminium conductor, with steel cores to provide strength, are used extensively on our subtransmission network. They are our preferred technology today. ACSR is characterised by its high strength, good conductivity, and lower cost compared to copper. It performs well in snow, wind and ice environments, which are frequently experienced in our region.

14.4.1.2 Asset population and age

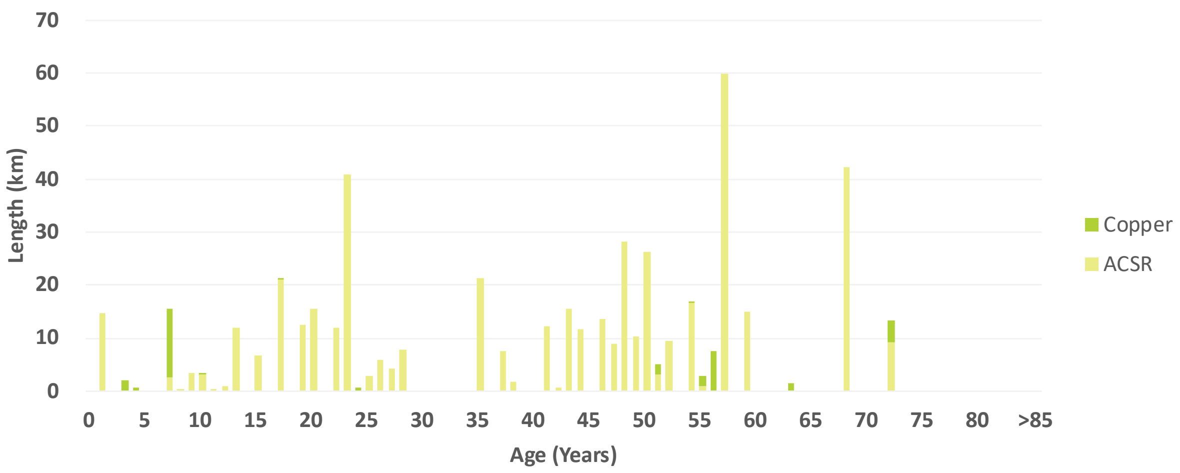
The table below summarises our population of subtransmission conductor by type.

Table 14.12 Population – subtransmission conductor

Asset type	Approx. Length (km)
HD copper	34
ACSR	480
Total	**514**

The figure below shows the age profile of our subtransmission conductor fleet.

Figure 14.16 Age profiles – subtransmission conductor

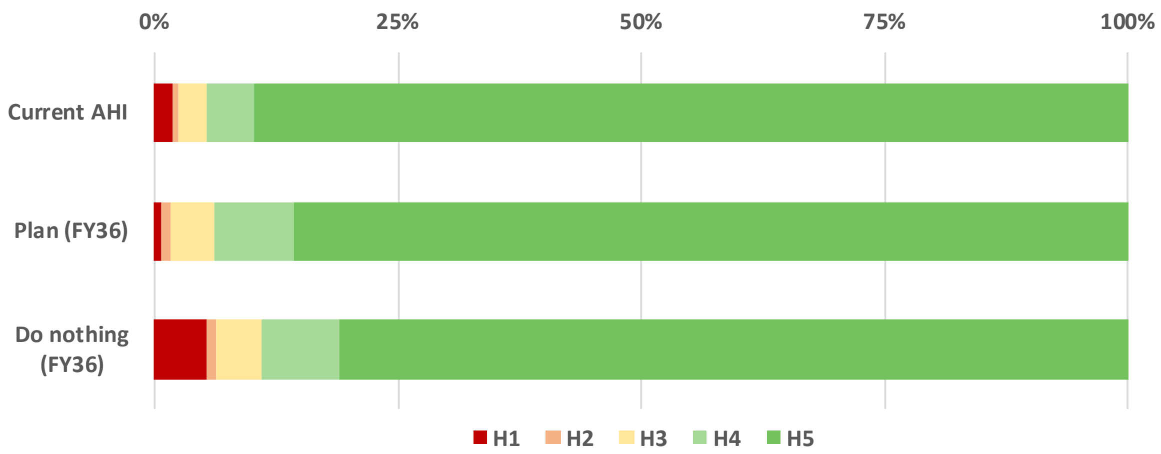


Both copper and ACSR conductor have an expected life of about 60 years, although this can vary with conductor size and operating environment, i.e. corrosion zone, from 48 to 94 years. Some of our subtransmission conductor is over 60 years of age. Our 66 kV conductor falls into two distinct age groups. Our oldest circuits were constructed in the later 1950s; these make up about one third of our total 66 kV transmission lines.

14.4.1.3 Asset health

We have adopted two approaches to derive future asset health: individual projects (based on poor condition), and Repex (minor works) based on corrosion zone, type, and conductor size . The figure below sets out asset health scores for our subtransmission conductor fleet.

Figure 14.17 Asset health – subtransmission conductor



Our subtransmission conductor fleet is in reasonable health overall except for a double circuit 66kV line that is in poor condition. Our planned renewals for the 66kV line and other minor renewals will improve overall fleet health over the AMP period.

We have conducted detailed Cormon testing on our 66 kV conductor and several returned poor results, including the Bromley to Heathcote, Islington to Halswell, and Heathcote to Halswell 66 kV lines. Several have earth wires that are also in poor condition. This is not unexpected given their coastal location.

The Bromley to Heathcote circuit, as well as being coastal, is in an industrial and estuarine area, both of which exacerbates corrosion; some sections are in very poor condition, with loss of zinc coating on the spans crossing the estuary. This presents both environmental and public safety risks. This line is due for replacement.

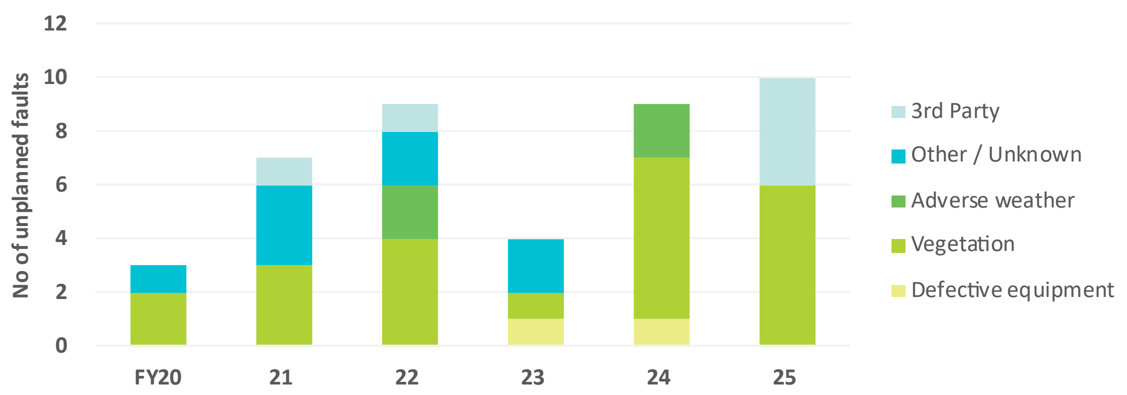
Some of our oldest 33 kV copper conductor are also showing signs of deterioration. These are found predominantly in rural areas. We are monitoring their condition during routine inspections.

Deferring planned renewals would see an increase in H1 levels, as depicted in the hypothetical 'Do Nothing' scenario, and will lead to increased public safety and reliability risks.

14.4.1.4 Asset performance and risk

The performance of this fleet, based on number of faults, is shown in the figure below.

Figure 14.18 Performance – number of faults



The two defective equipment faults in FY23 and FY24 relate to broken binders, which attach conductors to insulators. We saw more unplanned faults in FY25 than in previous years, many caused by incidents involving third parties. The FY25 vegetation faults relate to an event where a tree hit the line while contractors were carrying out tree trimming, causing loss of supply to the Barnett Park and Heathcote zone substations.

The table below summarises the key risks we have identified for our subtransmission conductor.

Table 14.13 Identified risks and mitigations – subtransmission conductor

Risk Area	Description	Mitigations
Network interruption	Conductor degrade over time due to fretting, corrosion, and fatigue.	Visual inspections Cormon testing Renewals
Network interruption	Snow and ice on conductor can cause excessive loads. Lines can clash in high winds leading to conductor damage causing outages.	Conductor sag is addressed through the overhead line defects programme Design standards
Network interruption	Clearance from the road surface may change over time because of road resurfacing, vehicle contact with poles, or conductor sagging too low.	Conductor road crossing heights are inspected and maintained for compliance with NZECP34 LiDAR programme
Network interruption Health and safety	Trees in contact with conductor can cause damage to the conductor and heighten the risk of electrocution for anyone coming into contact.	Vegetation control work programme to meet the Electricity (Hazards from Trees) Regulations 2003. Public information campaign

14.4.1.5 Renewal strategy

Our preventive maintenance inspections and testing identify subtransmission conductor for replacement. We also identify minor renewal needs from inspections and Cormon testing and use LiDAR (in conjunction with Transpower) to identify renewals required to address clearance violations.

Table 14.14 Renewal strategy – subtransmission conductor

Tasks	Description
Renewal trigger	Condition Subtransmission clearance violations – identified from LiDAR assessments
Forecasting approach	We forecast proactive renewal volumes of subtransmission conductor using: • Individual projects (poor condition) • Repex (minor works) – corrosion zone, type and size based
Cost estimation	Tailored estimation Volumetric

14.4.1.6 Renewal forecasting approach

We have adopted two renewal forecasting approaches for our subtransmission conductor fleet: identified forecasts and Repex.

We primarily use an individualised approach to forecast our major subtransmission conductor replacements. These circuits are replaced based on condition and risk, as assessed for each circuit. We determine the degradation trend over time for each conductor and estimate when replacement will likely be warranted. Individual business cases/options analyses are prepared for such major asset renewal projects, supported by additional assessments of condition. For a list of major asset renewal projects, see Appendix E.

Clearance violations are also identified individually. We will restring or retighten the conductor, if possible, but may require a redesign if this is insufficient to resolve the violation.

For all other work in this fleet, i.e. volumetric subtransmission renewals, we use a Repex approach to assess the asset health of the conductor sub-fleets (where a sub-fleet is defined by type of conductor, size, and corrosion zone) and forecast the volume of replacements required in each year of the AMP period.

14.4.2 Distribution conductor

14.4.2.1 Asset overview

Our distribution conductor fleet is made up of four main types:

1. **HD copper**: while some of this type remains, we no longer install it due to cost.
2. **ACSR**: its strong steel core makes this type particularly suitable for rural applications with long conductor spans. It performs well in snow, wind, and ice environments often seen in these areas.
3. **All Aluminium Conductor (AAC) and All Alloy Aluminium Conductor (AAAC)**: these are stranded aluminium alloys, both of which have a good strength to weight ratio and good corrosion resistance. The industry trend is toward AAAC, as it has a better strength to weight ratio, improved electrical properties, and better resistance than AAC.
4. **Smooth Bodied Conductor (SBC)**: this type can be aluminium or copper. In contrast to the stranded conductor, this type has a smooth, uniform outer surface.

14.4.2.2 Asset population and age

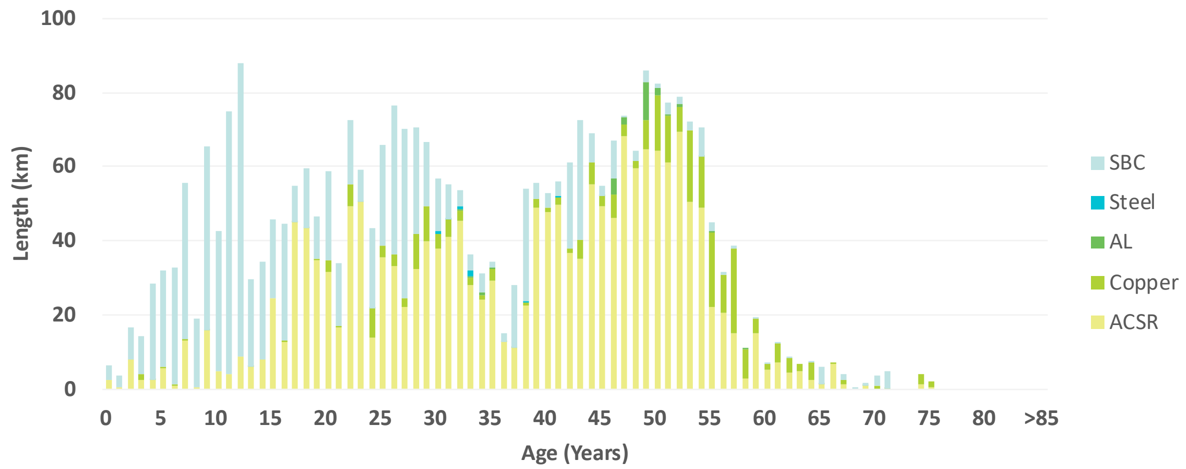
The table below summarises our population of distribution conductor by type. We use a combination of bare and covered conductor at distribution voltages.

Table 14.15 Population – distribution conductor

Asset type	Approx. Length (km)
Hand drawn copper	261
ACSR	1,791
AL	23
SBC	1,018
Steel	3
Total	**3,096**

The figure below shows the age profile of our distribution conductor fleet. The smaller conductor found on our distribution network have a shorter expected life than the larger conductor used at 33 kV and 66 kV, particularly if located near the coast. A sizable volume of our ACSR distribution conductor will be nearing their end of life over the AMP period.

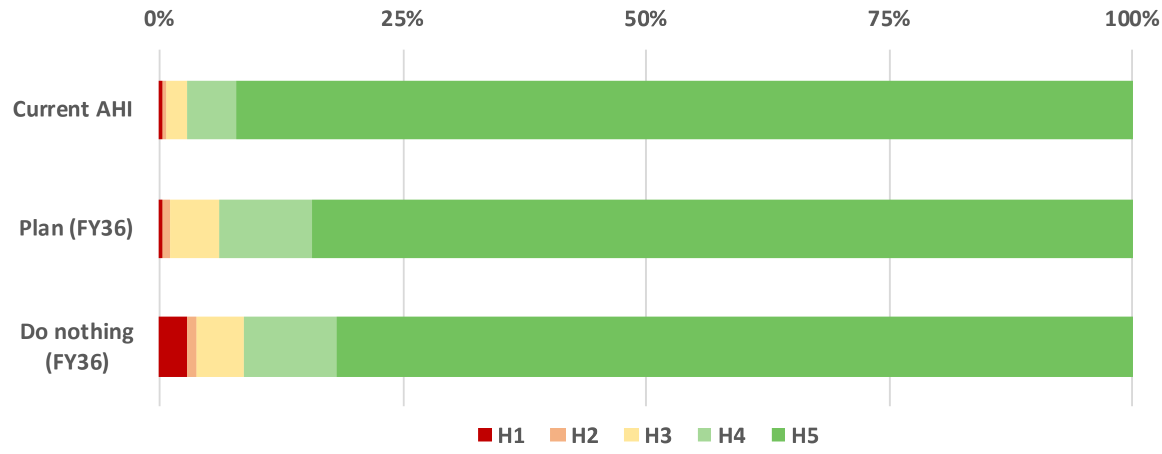
Figure 14.19 Age profiles – distribution conductor



14.4.2.3 Asset health

We have adopted an age-based Repex approach to derive future asset health. That approach determines how many kilometres of conductor need replacing, based on existing age profile and historical age at end of life for that asset type, size, and location. The figure on the following page sets out an overview of the asset health scores for our distribution conductor fleet.

Figure 14.20 Asset health – distribution conductor



Overall distribution conductor fleet health is good. We expect that only small amounts of conductor will need to be replaced over the AMP period. Our planned renewals aim to maintain fleet health, managing overall public safety and reliability risks. They will also focus on problematic small diameter copper conductor. Deferring planned renewals would see an increase in H1 levels, as depicted in the hypothetical 'Do Nothing' scenario, and will lead to increased public safety and reliability risks.

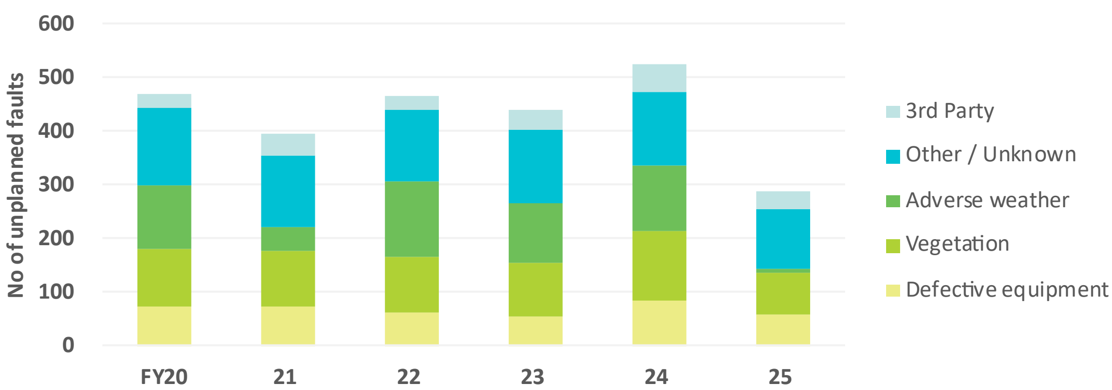
14.4.2.4 Asset performance and risk

Most faults in the past five years have been caused by vegetation and adverse weather. Some vegetation species have grown more quickly than we were able to address through our scheduled vegetation management programme. We have seen an increase in lightning strikes in recent years, mainly in rural and Banks Peninsula areas, as well as an increase in possums contacting overhead lines. We have been installing possum guards on some concrete poles in the locations of significant outage issues.

In recent years, we identified and replaced several distribution conductor populations that are not performing as well as expected. These were mostly older, small sized copper types, but also included several ACSR and steel types. We also installed remote line switches on our network, enabling faster switching and network restoration in response to faults.

The performance of this fleet is measured by monitoring the number of faults, as shown in the figure below.

Figure 14.21 Performance – number of distribution conductor faults



Faults caused by defective equipment are attributable to lines clashing, conductor falling off insulators, and conductor breaking. The last issue is due to a design issue with connectors between conductor and fuses in rural areas. We are progressively replacing these connectors with a different type as they break or when other work is undertaken on the assets.

The table below summarises the key risks we have identified for our distribution conductor.

Table 14.16 Identified risks and mitigations – distribution conductor

Risk Area	Description	Mitigations
Network interruption	Conductor degrade over time due to fretting, corrosion, and fatigue.	Visual inspections. Overhead line defects programme. Renewals.
Network interruption	Snow and ice on conductor can cause excessive loads. Lines can clash in high winds leading to conductor damage causing outages.	Conductor sag is addressed through the overhead line defects programme. Design standards.
Network interruption	Clearance from the road surface may change over time because of road resurfacing, vehicle contact with poles, or conductor sagging too low.	Conductor road crossing heights are inspected and maintained for compliance with NZECP34.
Network interruption Health and safety	Trees in contact with conductor can cause damage to the conductor and heighten the risk of electrocution for anyone coming into contact.	Vegetation control work programme to meet the Electricity (Hazards from Trees) Regulations 2003. Public information campaign.

14.4.2.5 Renewal strategy

We are moving to increased standardisation of our conductor fleet to improve our lifecycle economics and repairability.

One option for replacing end of life distribution conductor is converting them to underground cables. We consider replacing overhead assets in high density areas, e.g. around schools, where the consequences of failure are greater. Undergrounding also improves reliability and resilience to extreme weather.

Table 14.17 Renewal strategy – distribution conductor

Task	Description
Renewal trigger	Condition. Failure.
Forecasting approach	We forecast renewal volumes of distribution conductor using Repex modelling – corrosion zone, type, and size based.
Cost estimation	Volumetric.

14.4.2.6 Renewal forecasting approach

We have adopted a Repex renewal forecasting approach for our distribution conductor fleet. The unit rate is based on an estimated average cost covering a wide range of brownfield conditions. The rates are externally reviewed and maintained in a centrally managed price-book which is reviewed and updated annually.

14.4.3 Low voltage conductor

14.4.3.1 Asset overview

Our LV conductor fleet is made up of a variety of copper and aluminium conductor types, mainly PVC covered. While our LV conductor is mostly copper, we only install this type on our LV network when carrying out replacement works. For new lines we use aluminium conductor, with the type chosen being influenced by cost considerations, asset location, and environmental and performance factors.

14.4.3.2 Asset population and age

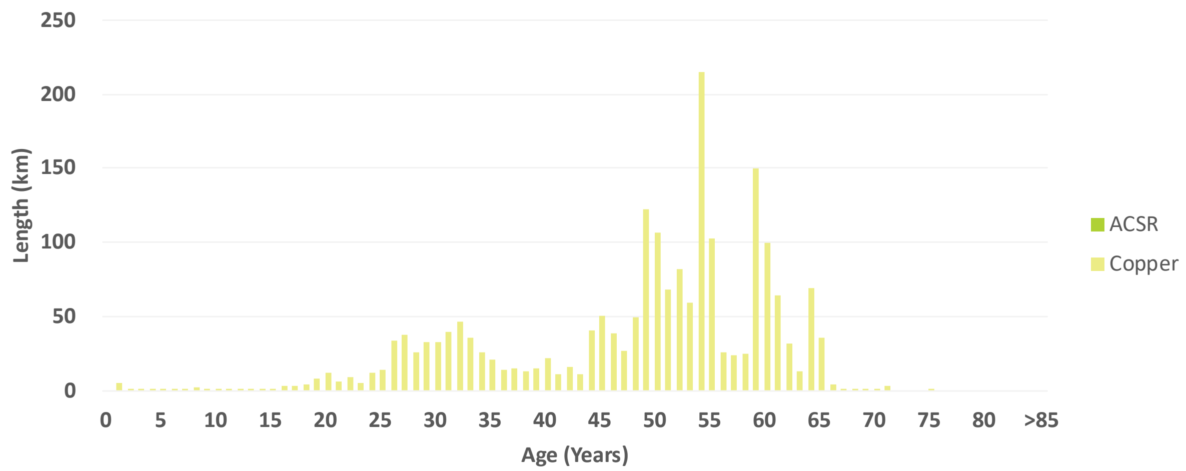
The table below summarises our population of LV conductor by type. We also have a large amount of copper streetlighting conductor but that is not included in the population table.

Table 14.18 Population – LV conductor

Asset type	Approx. Length (km)
Copper	2,056
Aluminium (AAC)	232
Total	**2,288**

The figure below shows the age profile of our LV conductor fleet. Most of our LV conductor are more than 40 years old, with the majority being over 50 years of age. This is mainly due to underground cables being favoured for connecting new developments, resulting in low volumes of new LV conductor.

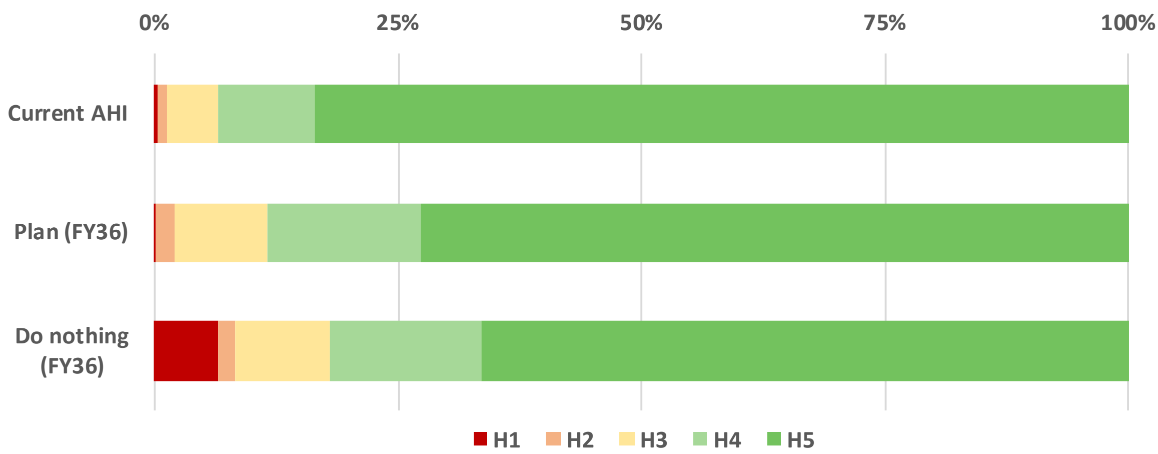
Figure 14.22 Age profiles – LV conductor



14.4.3.3 Asset health

We have adopted an age-based Repex approach to derive future asset health. Our approach determines how many kilometres of a particular size, type, and location of conductor needs replacing, based on existing age profile and the statistical distribution that describes the historical age at end of life for that asset type. The figure below sets out asset health scores for our LV conductor fleet.

Figure 14.23 Asset health – LV conductor



The asset health of our LV conductor is good, with only a small amount needing replacement within the AMP period. Our planned renewals will focus on problematic small diameter copper conductor, maintaining overall fleet health. Deferring these planned renewals would see an increase in H1 levels, as depicted in the hypothetical 'Do Nothing' scenario, and will lead to increased public safety and reliability risks.

14.4.3.4 Asset performance and risk

We are not required to record SAIDI or SAIFI for our LV network. However, we have begun collecting performance data on our LV system for asset management purposes. This is a work in progress, and we cannot present performance data yet.

The table below summarises the key risks we have identified for our LV conductor.

Table 14.19 Identified risks and mitigations – LV conductor

Risk Area	Description	Mitigations
Network interruption	Conductor degrade over time due to fretting, corrosion, and fatigue	Visual inspections Renewals
Network interruption	Snow and ice on conductor can cause excessive loads. Lines can clash in high winds leading to conductor damage causing outages	Conductor sag is addressed through the overhead line defects programme Design standards
Network interruption	Clearance from the road surface may change over time because of road resurfacing, vehicle contact with poles, or conductor sagging	Conductor road crossing heights are inspected and maintained for compliance with NZECP34
Network interruption Health and safety	Trees in contact with conductor can cause damage to the conductor and heighten the risk of electrocution for anyone coming into contact	Vegetation control work programme to meet the Electricity (Hazards from Trees) Regulations 2003. Public information campaign

14.4.3.5 Renewal strategy

In the past we did not have a proactive scheduled replacement plan for LV conductors, instead we addressed any isolated sections requiring repair or replacement under emergency maintenance. As the LV conductor population is ageing, a more proactive approach is now warranted. We can use modelling to identify when conductor is nearing end of life, based on age, type, size, and location relative to the coast.

Table 14.20 Renewal strategy – LV conductor

Tasks	Description
Renewal trigger	Condition Failure
Forecasting approach	We forecast renewal volumes of LV conductor using Repex modelling – corrosion zone, age, type, and size based
Cost estimation	Volumetric

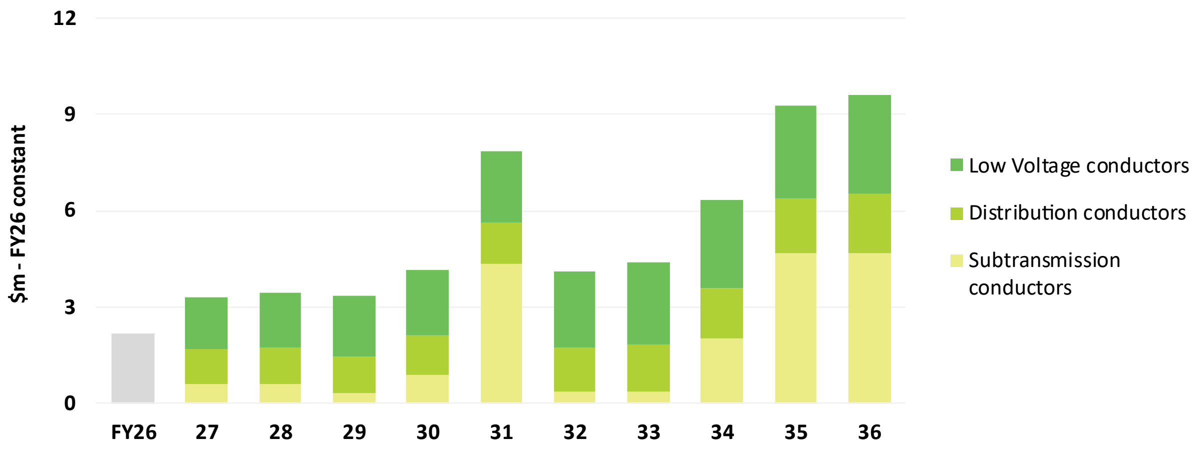
14.4.3.6 Renewal forecasting approach

We have adopted a Repex renewal forecasting approach for our LV conductor. The unit rate is based on an estimated average cost covering a wide range of brownfield conditions. The rates are externally reviewed and maintained in a centrally managed price-book which is reviewed and updated annually.

14.4.4 Overhead conductors forecast capex

The following figure shows our forecast capex for overhead conductors.

Figure 14.24 Planned overhead conductors renewals capex



Our planned renewal capex for subtransmission conductors is relatively small over the CPP period, other than major asset renewal of the 66kV line in FY30-31. We are also planning to replace another 66kV line later in the AMP period, and we are in the process of confirming its condition. Our distribution and LV conductor renewals, in the short term, will predominantly focus on small diameter copper conductors, which is a known poor performing type of conductor in the wider industry. Towards the end of the AMP period, we will transition over time to replace other types of conductors.

14.5 Underground cables

The role of underground cables is to move electricity around our network. This section outlines the asset fleets that make up our underground cables asset class:

- subtransmission cables (33kV & 66kV)
- distribution cables (11kV)
- low voltage cables (230/400V).

14.5.1 Subtransmission cables

14.5.1.1 Asset overview

The primary purpose of the cable network is to distribute electricity from Transpower's GXPs to Orion's zone substations, as well as in between our zone substations, across the region.

Our subtransmission cables fleet is made up of three types:

- **Cross linked polyethylene insulated (XLPE)**: our current standard cable type on our subtransmission network is 3 x single core XLPE. Two types are used: lead armoured sheath and aluminium armoured sheath (CAS), both are typically installed in a weak mix 'Thermal Fill' concrete.
- **Self-contained oil-filled (SCOF)**: traditionally, pairs of radial SCOF 3 core 300mm2 Al, corrugated aluminium sheath cables were installed to supply many of our 66 kV/11 kV zone substations. The cables are encased in a thermally stabilised weak-mix concrete and capped by a thin layer of harder red dyed concrete. The construction of these cables makes them vulnerable to earthquake-induced ground movements. This cable type is only in use on our 66 kV network, as all our historic oil-filled 33 kV cables have been replaced with XLPE.

- **Paper insulated lead covered (PILC)**: we have some short lengths of typically either 300mm2 (Al) or 185mm2 (Cu) 33 kV PILC remaining on our 33 kV network. PILC is generally very reliable provided it is not disturbed or located in high water table zones.

The subtransmission cable fleet also includes various joints and terminations.

14.5.1.2 Asset population and age

The table below summarises our population of subtransmission cables by type.

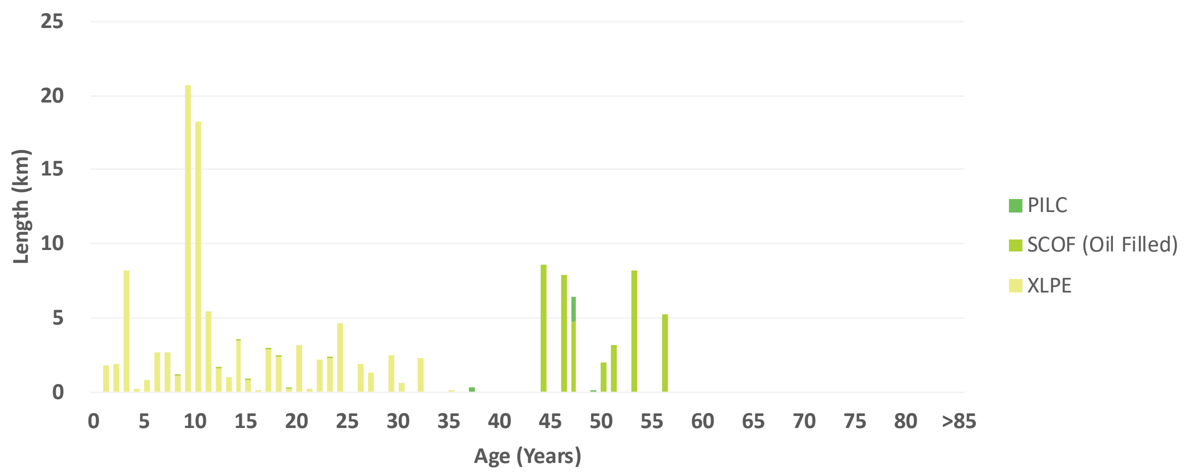
Table 14.21 Population of transmission cables by type

Asset type	Approx. Length (km)
XLPE cable	98
SCOF (oil-filled) cable	40
PILC cable	2
Total	**140**

We have a programme of work to replace the remaining 66 kV oil-filled cable as it reaches end of life (see Appendix E for a list of major asset renewal projects). There are 12 remaining 66 kV oil-filled circuits. While they have an expected life of 60 years, they were damaged during the Canterbury earthquakes and have been rejointed and repaired since that time. Most will be replaced before 60 years of age due to poor condition, largely due to ground movement.

The figure below shows the age profile of our subtransmission cables fleet.

Figure 14.25 Age profiles - subtransmission cables

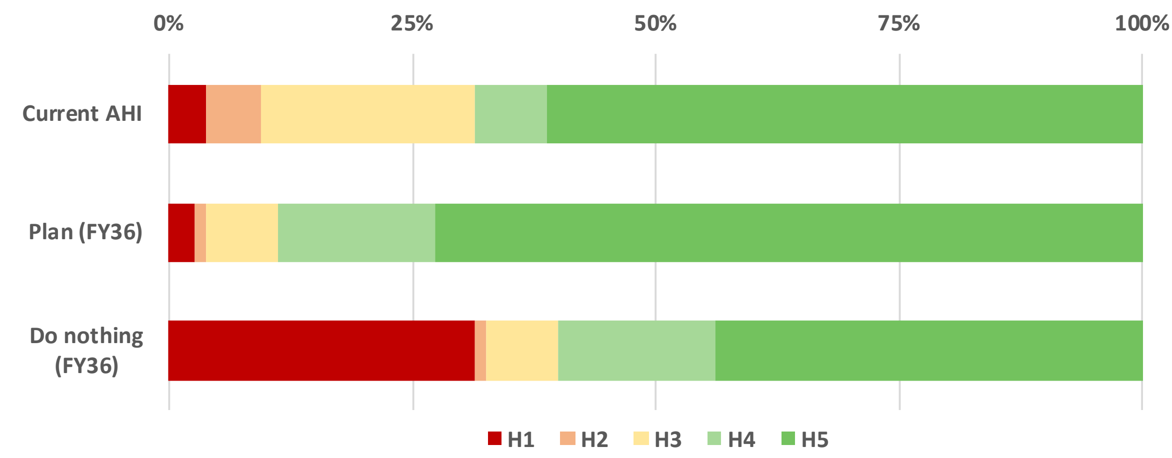


The age profile shows the recent adoption of XLPE cable in place of traditional PILC or oil-filled cables. A significant portion of our network still consists of 66 kV oil-filled cables. They require maintenance, and specialist expertise to repair, and recovery times are lengthy in the event of external damage or a fault. We plan to replace these cables to ensure that service levels continue to be achieved, and to increase resilience in the event of earthquakes.

14.5.1.3 Asset health

We have adopted two approaches to derive future asset health: individual projects for oil-filled cables, and Repex for non-oil-filled cables. The figure below sets out an overview of the asset health scores for our subtransmission cables fleet.

Figure 14.26 Asset health – subtransmission cables



Our XLPE cables are still well within their expected operating lifespan and are assessed to be in good serviceable condition. However, our oil-filled cables are not in good condition, having suffered significantly from the ground movement of the Canterbury earthquakes. They are equipped with corrugated aluminium conducting and protective polyethylene outer sheaths. The sheaths are in poor condition which increases the risk of insulation degrading, leading to cable failure and the potential for oil-leaks, which is an environmental issue.

In particular, the Addington to Milton and Halswell to Hoon Hay 66 kV oil-filled cables have ongoing oil leaks which we have been unable to locate and repair. This is driven, in part, by the fact that the cable designs had them installed in a weak concrete mix of thermal backfill which has hardened over time. The cables have become obsolete, and it is getting increasingly difficult to source parts and expertise.

The small amount of 33 kV PILC cable remaining in service is deemed to be in serviceable condition and is not expected to need replacement in the near term.

Our plan over the AMP period is to replace the 66 kV oil-filled cables with modern XLPE types. In addition, we have undertaken a 66 kV network-wide architecture review which will convert our current radial network to a meshed architecture. This will enhance overall network resilience, especially against large scale disasters like earthquakes, and improve network reliability. We are expecting to fully remove the oil-filled cable circuits by 2039.

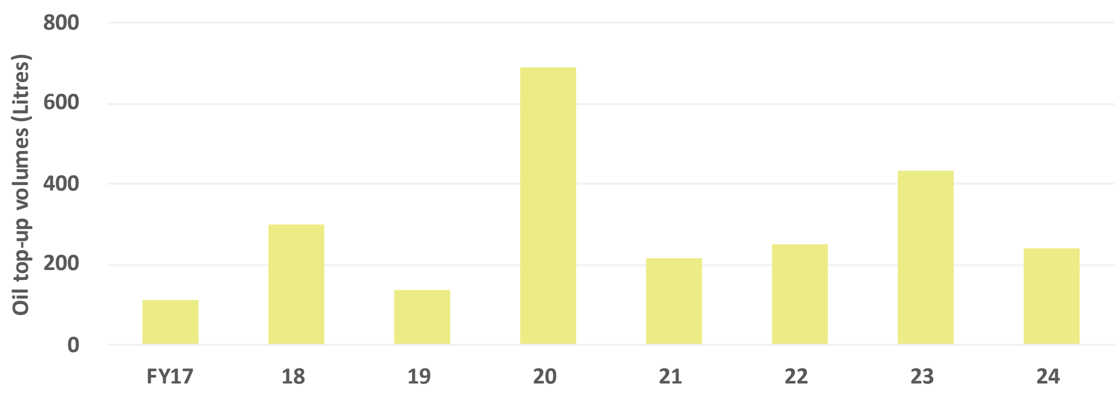
14.5.1.4 Asset performance and risk

We experienced a period of reduced reliability due to latent defects stemming from the 2011 Christchurch earthquakes. Since resolving these defects, our 66 kV cables are now achieving our target reliability levels. However, historically, cable faults were only recorded if they caused an outage. We do encounter occasional issues related to terminations and oil leaks, requiring immediate repairs. At the 33 kV level, the only significant issue at present is with an XLPE cable in Papanui which is showing sheath corrosion.

The figure below shows oil top up volumes for our subtransmission cables, which provides a proxy for the volume of oil leaks from these cables. The main contributor is the Addington–Milton–2 cable, for which we unsuccessfully searched for the source of the leak in FY20. We are continuing to monitor and record oil volume top-ups, but the leak does not appear to have worsened since then.

The oil leaks are low risk to the environment; external advisors noted that the oil was not harmful or toxic to aquatic life. However, the on-going oil leak does indicate a deteriorated condition, and continual top-ups increase maintenance costs. There is also likely to be an increased risk of failure compared to cables that are not leaking.

Figure 14.27 Performance – subtransmission cables – oil top-up volumes



The table below summarises the key risks we have identified for our subtransmission cables.

Table 14.22 Identified risks and mitigations – subtransmission cables

Risk Area	Description	Mitigations
Network interruption	Cable material degradation (all voltages). Partial discharge degrades the cable insulation which can result in complete failure leading to an outage.	Targeted offline partial discharge testing to identify joint or cable defects before failure. Ultrasonic and partial discharge monitoring within zone substations to identify early signs of potential cable termination failure.
Network interruption	Installation quality (all voltages). Poor quality joint and termination installation can lead to premature failure, affecting reliability. Poor cable installation techniques including improperly compacted or incorrect fill material and overstressing or over-bending can lead to premature failure.	Cable jointers are trained and certified as competent by the joint supplier for the specific joint type. We perform root cause investigations of failures to determine if there are common causes, such as work or material quality, so that mitigation or remediation actions can be identified. Quality control surveillance of service delivery partners during the laying of cables to verify correct installation techniques are being employed. Routine substation inspections to identify failing 11 kV terminations.
Network interruption	Third parties dig up and damage our cables during civil works.	33 kV and 66 kV cables require a consent application and stand over process for any work in their immediate vicinity. We run a cable awareness programme targeted at civil works contractors to minimise the risk of cable disturbance while working near cables. We specify orange-coloured sheaths to provide visual indication of live cables. Advertising to create awareness of hazards of working near cables; together with free training on working safely around cables. No joints are allowed within road intersections.

Table 14.22 Identified risks and mitigations – subtransmission cables

Risk Area	Description	Mitigations
Network interruption	Oil-filled cables require specialised skills for repair, which are labour intensive, requiring scarce specialised skills, equipment and spare parts. Given the limited quantity of these cables, and their infrequent need for repairs, maintaining in-house repair capabilities is impractical. This means we are reliant on specialist service delivery partners who have limited availability, further compromising our response capability.	Agreements in place with specialised service delivery partners to maintain local repair capability. A selection of repair joints and cable is retained in stock.
Network interruption Environmental Health and safety	Oil-filled cables, if breached, can cause discharge, a loss of oil causing electrical damage and failure to the cable. Oil leaks can contaminate sensitive environmental areas. These leaks are typically small in volume but expensive and difficult to detect and repair.	Periodic sheath testing to identify failure of the insulating outer sheath which is an early indicator of potential sheath corrosion and subsequent leaks. Monitoring of cable pressures to identify developing problems so that they may be rectified in their early stages. Renewal
Network interruption	The construction of our 66 kV oil-filled cables makes them vulnerable to earthquake-induced ground movements. There is also a seismic vulnerability with having dual oil-filled circuits located in the same trench, such that a significant ground movement would likely affect both circuits. Our 66 kV cable network is installed predominantly in the urban areas of Christchurch. Restoration of a single fault on our 66 kV oil-filled cables typically takes several days at a minimum and longer if multiple failures occur simultaneously as would be expected in a significant earthquake event such as an Alpine Fault rupture.	Renewal

14.5.1.5 Renewal strategy

Our oil-filled subtransmission cables are nearing end of life, and in FY23 we began the 66 kV replacement programme to replace the aged cables. While the renewals are like for like (similar capacity and routes), our approach involves changing the architecture of the urban 66 kV network from radial to a meshed 'ring', to create supply diversity, improve supply security and strengthen connections between the two major urban GXPs. This replaces existing capacity and allows for growth, and also provides additional resilience against seismic events. We will continue with the work programme to replace the remaining oil-filled cables over the next ten to fifteen years. For a list of major asset renewal projects, see Appendix E.

Table 14.23 Renewal strategy – subtransmission cables

Tasks	Description
Renewal trigger	Condition
Forecasting approach	We forecast renewal volumes of subtransmission cables as Identified
Cost estimation	Tailored estimates (major asset renewal)

14.5.1.6 Renewal forecasting approach

Subtransmission cable renewals are based on replacing all our oil-filled cables with projects being stood up for each circuit replacement. The projects are scrutinised via our business case process which includes options analysis, where capital costs are weighed against benefits and qualitative assessment criteria. A preferred option is then selected and the forecast is based on its capital cost.

14.5.2 Distribution cables

14.5.2.1 Asset overview

The distribution cables fleet includes our 11 kV underground cable network, primarily located in urban Christchurch. These cables deliver power from our zone substations and feed our distribution substations or connect directly to customers.

Our distribution cables fleet is made up of two types:

1. **PILC**: commonly used prior to 2000 and has many variations in joint and cable structure due to advancements in manufacturing processes and installation methods over the period of its use.
2. **XLPE**: our current standard cable type used on our 11 kV network. It includes both single-core and three-core, aluminium and copper core construction.

14.5.2.2 Asset population and age

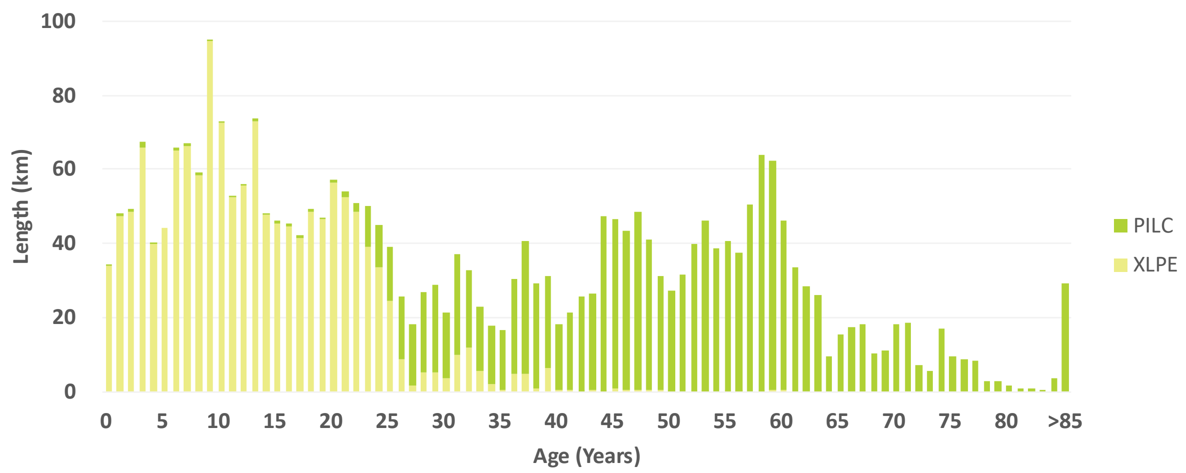
The table below summarises our population of distribution cables by type.

Table 14.24 Population – distribution cables

Asset type	Approx. Length (km)
XLPE	1,425
PILC	1,502
Total	**2,927**

The figure below shows the age profile of our distribution cables fleet.

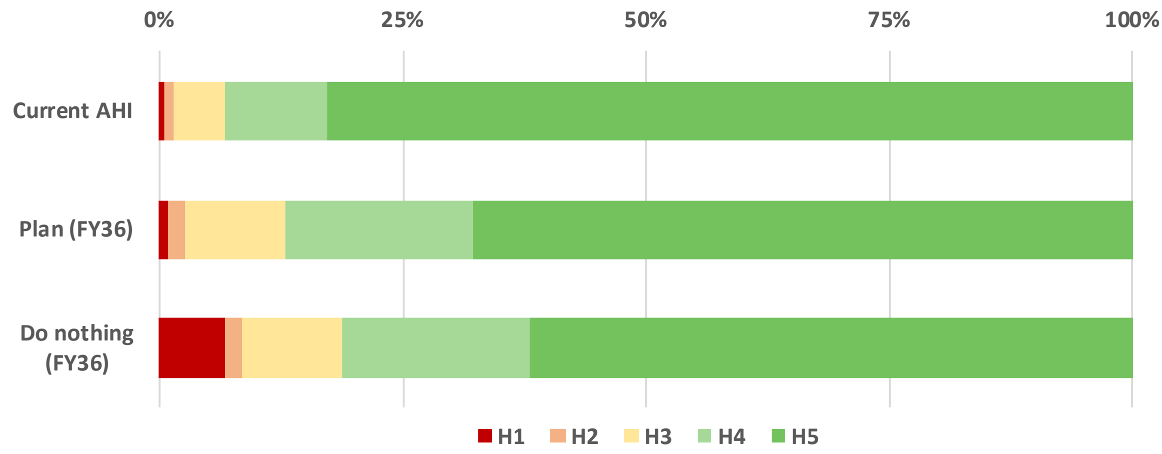
Figure 14.28 Age profiles – distribution cables



14.5.2.3 Asset health

The figure below sets out asset health scores for our distribution cables fleet.

Figure 14.29 Asset health – distribution cables

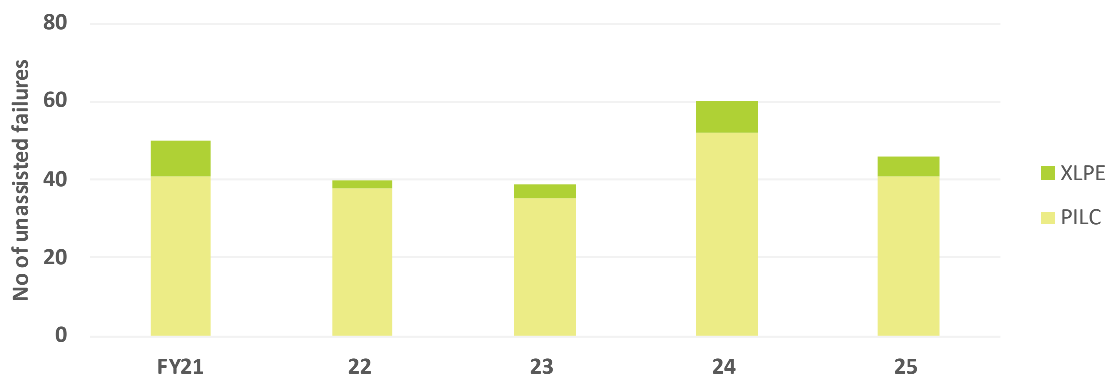


Our distribution cable asset health is generally in good condition. The proportion of assets with a H1 score is predominantly driven by old age, poor performing PILC cables. Our PILC cables have a very high joint density, which is an indicator of past failures, when compared to XLPE types. This also concurs with historical performance where 90% of failures in the last 5 years were attributed to PILC cables. Our distribution cable renewal plans aim to maintain overall fleet health, focusing on the replacement of PILC cables for the AMP period. Deferring these renewals would increase PILC cable failures, with an associated increase in reliability risk.

14.5.2.4 Asset performance and risk

Failure of distribution cables to deliver power from zone substations to distribution substations and larger customers poses a significant reliability risk. When a cable fails, it is typically difficult to locate the fault and takes a substantial amount of time to replace the cable section and return it to service. The figure below shows the unassisted failures by cable type.

Figure 14.30 Unassisted failures by cable type



Most of our unassisted failures relate to PILC cables which indicate that this population is not performing as well as we would expect. This was anticipated due to the population of PILC cables being much older, having been damaged by the 2011 earthquakes, and having many more joints per km compared to XLPE cables. Most of the PILC cable faults are caused by joint failures; these are due to a combination of installation quality and ageing from time and thermal cycles. Land movement and water ingress also contribute to failures, particularly affecting PILC cables.

The table below summarises the key risks we have identified for our distribution cables.

Table 14.25 Identified risks and mitigations – distribution cables

Risk Area	Description	Mitigations
Network interruption	Partial discharge degrades the cable insulation which can result in complete failure leading to an outage.	Targeted offline partial discharge testing to identify joint or cable defects before failure. Ultrasonic and partial discharge monitoring within zone substations to identify early signs of potential cable termination failure.
Network interruption	Poor quality joint and termination installation can lead to premature failure, affecting reliability. Poor cable installation techniques including improperly compacted or incorrect fill material and overstressing or over-bending can lead to premature failure.	Cable jointers trained and certified as competent by the joint supplier for the specific joint type. We perform root cause investigations of failures to determine if there are common causes, e.g. work or material quality, so that mitigation or remediation actions can be identified. Quality control surveillance of service delivery partners during the laying of cables to verify correct installation techniques are being employed. Routine substation inspections identify failing 11 kV terminations.
Network interruption	Third parties dig up and damage our cables during civil works.	We run a cable awareness programme targeted at civil works contractors to minimise the risk of cable disturbance while working near cables. We specify orange-coloured sheaths to provide visual indication of live cables. Advertising to create awareness of hazards of working near cables; free training on working safely around cables. Proactive promotion of cable maps and locating services to parties involved with civil excavations. No joints are allowed within road intersections.

14.5.2.5 Renewal strategy

As our PILC cables are ageing and have suffered damage due to ground movement, replacement is warranted in some cases to address poor condition and unsatisfactory performance. Planned replacement generally improves reliability, avoiding prolonged searches for faults and allowing for provision of alternative electricity supply.

We will also replace some overhead lines with underground cables due to ECP34 clearance violations or where there are safety risks, such as near schools, or high foot traffic areas. It may also be cost effective to underground some overhead lines that are dense with fast growing vegetation that must be managed.

We also replace distribution cables when we replace signalling and communication cables, if they are in a common trench or route. This is a sizable work programme, as damage to protection signalling cables during the Christchurch earthquakes has left us with few spare cores in some cables. This work is excluded from the distribution cable renewal forecasts, as it is included in the signalling and communications cable renewal programme.

Table 14.26 Renewal strategy – distribution cables	
Tasks	**Description**
Renewal trigger	Condition and/or performance Failure Overhead to underground conversions
Forecasting approach	We forecast proactive renewal volumes of distribution cables using: • Repex modelling • Overhead to underground conversions based on identified issues, e.g. under-clearances
Cost estimation	Volumetric

14.5.2.6 Renewal forecasting approach

We have adopted the Repex approach for our distribution cables, using an expected life of 50 years for XLPE cables and 80 years for PILC cables. We are also planning to convert overhead lines to underground cables per year starting in the CPP period. We anticipate this will continue beyond the CPP period. The unit rate is based on an estimated average cost covering a wide range of brownfield conditions. The unit rate provides for replacing distribution cables, including trenching and traffic management costs.

14.5.3 Low voltage cables

14.5.3.1 Asset overview

Our LV cables fleet is made up of three types:

1. **PILC**: used up until the mid-1960s. Some of this cable is approaching 90 years in service.
2. **PVC**: replaced PILC from the mid-1960s, primarily due to cost. It uses either copper or aluminium conductor.
3. **XLPE**: superseded PVC from approx. 1974, mainly due to having better thermal properties, allowing higher operating temperatures, and improving economics.

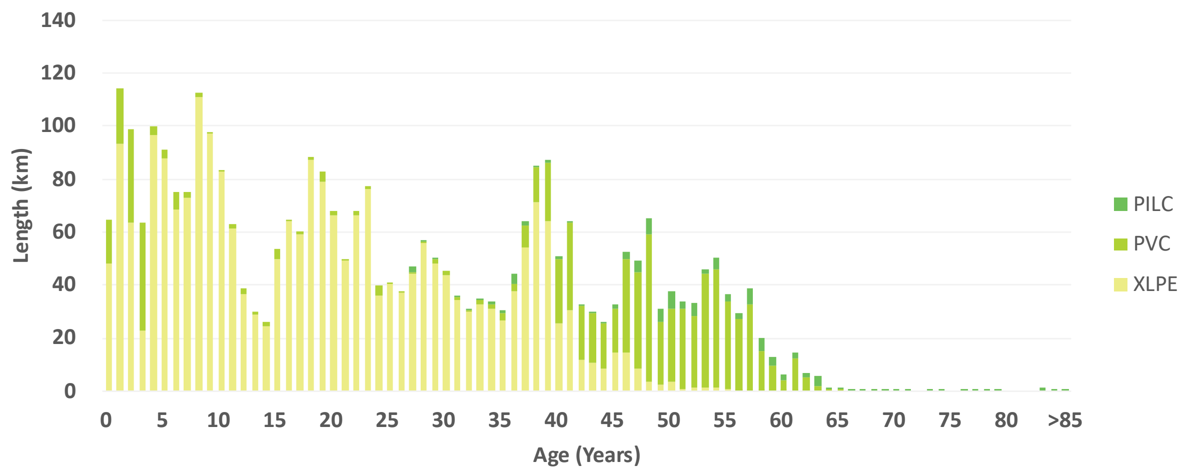
14.5.3.2 Asset population and age

The table below summarises our population of LV cables by type:

Table 14.27 Population – LV cables	
Asset type	**Circuit km**
PILC	149
PVC	752
XLPE	2,420
Total	**3,321**

The figure below shows the age profile of our LV cables fleet.

Figure 14.31 Age profiles -LV cables

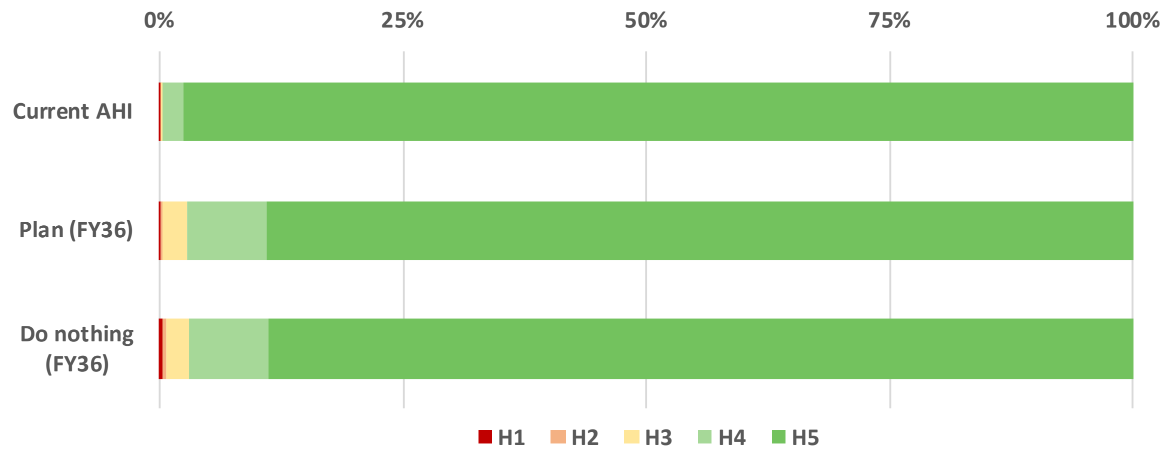


14.5.3.3 Asset health

We have adopted an age-based Repex approach to derive future asset health. The Repex model determines how many circuit kilometres need to be replaced in each future year based on the existing age profile of the assets, and the statistical distribution that describes the historical age at end of life for that asset type.

The figure below sets out an overview of the asset health scores for our LV cables fleet.

Figure 14.32 Asset health – LV cables



Overall LV cable fleet health is good with not many cables exceeding their expected life. Our renewal programme aims to maintain current levels of H1. The proportion of assets with a H3 score will grow over the AMP period, driven predominantly by ageing cables approaching the end of their expected life. However, given the fleet's relatively young age profile, and the lower reliability impact of fewer customers per circuit, the overall risk remains low.

14.5.3.4 Asset performance and risk

The table below summarises the key risks we have identified for our LV cables.

Table 14.28 Identified risks and mitigations – LV cables

Risk Area	Description	Mitigations
Network interruption	Partial discharge degrades the cable insulation which can result in complete failure leading to an outage.	Targeted offline partial discharge testing to identify joint or cable defects before failure. Ultrasonic and partial discharge monitoring within zone substations to identify early signs of potential cable termination failure.
Network interruption	Poor quality joint and termination installation can lead to premature failure, affecting reliability. Poor cable installation techniques including improperly compacted or incorrect fill material and overstressing or over-bending can lead to premature failure.	Cable jointers trained and certified as competent by the joint supplier for the specific joint type. We perform root cause investigations of failures to determine if there are common causes, e.g. work or material quality, so that mitigation or remediation actions can be identified. Quality control surveillance of service delivery partners during the laying of cables to verify correct installation techniques are being employed.
Network interruption	Third parties dig up and damage our cables during civil works	We run a cable awareness programme targeted at civil works contractors to minimise the risk of cable disturbance while working near cables. We specify orange-coloured sheaths to provide visual indication of live cables. Advertising to create awareness of hazards of working near cables; free training on working safely around cables. Proactive promotion of cable maps and locating services to parties involved with civil excavations. No joints are allowed within road intersections. Identified shallow LV cables addressed.

14.5.3.5 Renewal strategy

Due to inaccessibility, we cannot readily inspect the condition of our LV cables. Historically, we have used a run to failure approach. Failure risk (as indicated by AHI) will increase as the fleet ages and in FY27 we plan to initiate a proactive standalone renewal programme to address end of life LV cables.

Table 14.29 Renewal strategy – LV cables

Tasks	Description
Renewal trigger	Reactive
Forecasting approach	We forecast renewal volumes of LV cables using Repex modelling
Cost estimation	Volumetric

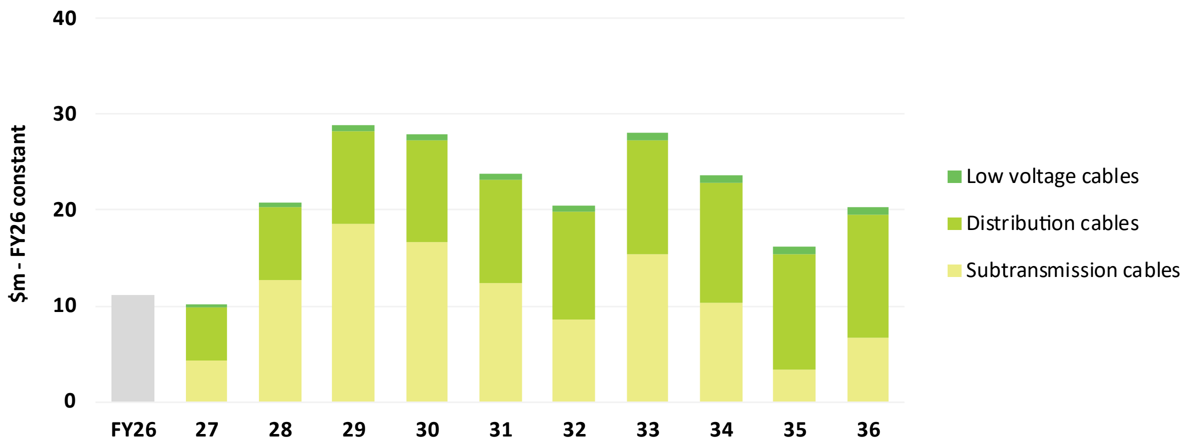
14.5.3.6 Renewal forecasting approach

We have adopted the Repex approach for our LV cables fleet, using expected lives of the XLPE, PVC, or PILC cable, being 70, 90, and 90 years, respectively.

14.5.4 Underground cables forecast capex

The following figure shows our forecast capex for underground cables.

Figure 14.33 Planned underground cables renewals capex



Our underground cables forecast over the AMP period will replace the majority of the 66 kV oil-filled cables under the subtransmission cables programme and replace many PILC type distribution cables. The subtransmission cable programme will take over and beyond the AMP period, planning to remove the oil-filled cable fleet by FY39.

Our distribution cables forecast will lift over the AMP period as we address the more than 50% of our fleet composed of PILC types. This programme is anticipated to continue beyond the AMP period as more PILC cables require replacement.

Our low voltage cables programme is relatively small, replacing short runs of cable when they fail. This run to failure strategy remains appropriate as the impact on reliability is relatively small.

14.6 Zone substations

Zone substations are critical hubs in our network, housing high voltage infrastructure that typically serves multiple suburbs. We have 52 zone substations in service, of the following types:

- **Zone substations**: these are sites containing network assets which transform subtransmission voltage (33 kV or 66 kV) to distribution voltage (11 kV).
- **11 kV zone substation/switching sites**: these are sites where two or more incoming 11 kV feeders are redistributed, or a ripple injection plant is installed. These sites do not have any power transformers, outdoor structures, or buswork.
- **Switching stations**: these are sites where redistribution of subtransmission feeders occurs. These sites are included in the zone substation class despite there being no voltage transformation.

Unlike our other asset classes, zone substation assets are managed in a highly integrated and system-focused manner. While we talk about the various equipment fleets individually, coordinated lifecycle planning across multiple components is essential to ensure operational continuity and support network resilience.

The zone substations asset class includes major projects (see Appendix E) that cover multiple asset fleets. Section 14.6.6. sets out the total for the asset class including the major renewal projects fleet-based renewal programmes for buildings and grounds, power transformer refurbishments, and ancillary equipment.

This section outlines the asset fleets that make up our zone substations asset class:

- power transformers
- indoor switchgear
- outdoor switchgear
- ancillary equipment
- buildings and grounds.

14.6.1 Power transformers

14.6.1.1 Asset overview

Power transformers are high value, critical, long lead-time network assets that are required to deliver reliable supply. They are installed at zone substations to transform subtransmission voltages of 33 kV and 66 kV to a distribution voltage of 11 kV. They are fitted with on-load tap changers and electronic management systems to maintain the required delivery voltage on the network.

Our fleet is made up of a range of subtransmission voltages and power transfer capacities, as set out in the table below:

Table 14.30 Voltage ranges

Voltage	Description
66 kV/11 kV single phase transformers	Single phase transformer banks provide three phase voltage transformation using three single and separate transformer units, rather than a single three phase transformer unit. A group of three single phase transformers connected in this configuration is referred to as a bank.
66 kV/11 kV zone substation transformers	Our urban zone substation transformers operate predominantly at 66/11 kV with the typical transformer size being 20/40 MVA. Indoor transformers are configured with HV and LV cable box terminations; they are located indoors primarily for noise reduction, but this also provides some benefit by reducing weather-related degradation. Outdoor units are typically fitted with bushing type HV terminations. Some older types can be readily converted from bushing to cable termination, increasing options in the event of a transformer failure. A range of cooling strategies are used, with some units utilising forced oil and forced air (oil pumps and cooling fans), and others utilising fans only. In some installations oil pumps are prioritised over fans to reduce operational noise. All indoor transformers have their cooling radiators located outdoors.
66 kV/33 kV zone substation transformers	We have two 30/60 MVA, 66/33 kV transformers, with oil forced and air forced cooling. These were built in 1980 and purchased from Transpower in 2014 as part of the Springston zone substation spur asset transfer. These transformers are outdoor units with both HV and LV bushings. The tap changer insulation medium is oil. We do not own a contingency spare for these units, however we have an informal agreement with Transpower to acquire its spare, if needed.
33 kV/11 kV zone substation transformers	Many of our rural zone substations operate at 33/11 kV voltages. There are a range of sizes in operation from the largest at 11.5/23 MVA to the smallest at 2.5 MVA. All units are located outdoors.

The power transformers fleet also includes bunding, oil containment, firewalls, and neutral earthing resisters, which are devices that limit the fault current that can flow through the neutral conductor of a transformer.

14.6.1.2 Asset population and age

The table below summarises our population of power transformers by rating type.

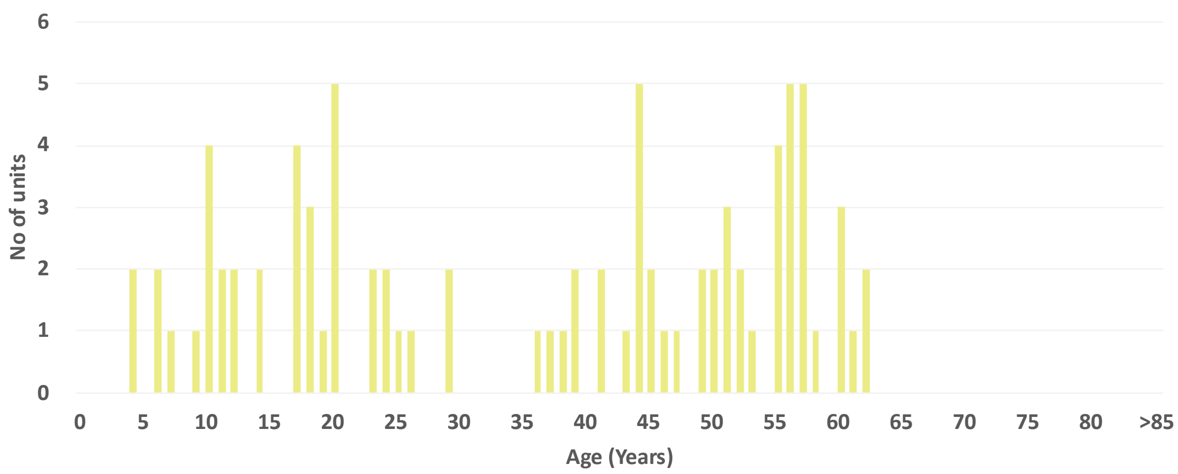
Table 14.31 Population – power transformers

Rating	Primary winding voltage		
	33 kV	**66 kV**	**Total**
Less than 10 MVA	7	0	7
10 to 20 MVA	8	6	14
20 to 40 MVA	10	20	30
Greater than 40 MVA	0	34	34
Total	**25**	**60**	**85**

The useful life of a power transformer can vary greatly depending on design, construction, and in-service loading. As most of our power transformers are part of a N-1 redundant system, they typically operate below their nominal capacity which lengthens their effective operating life. Our oldest transformers are ex-Transpower single phase transformers.

The figure below shows the age profile of our power transformers fleet. Some of our older transformers are scheduled for replacement due to their condition.

Figure 14.34 Age profiles – power transformers[57]

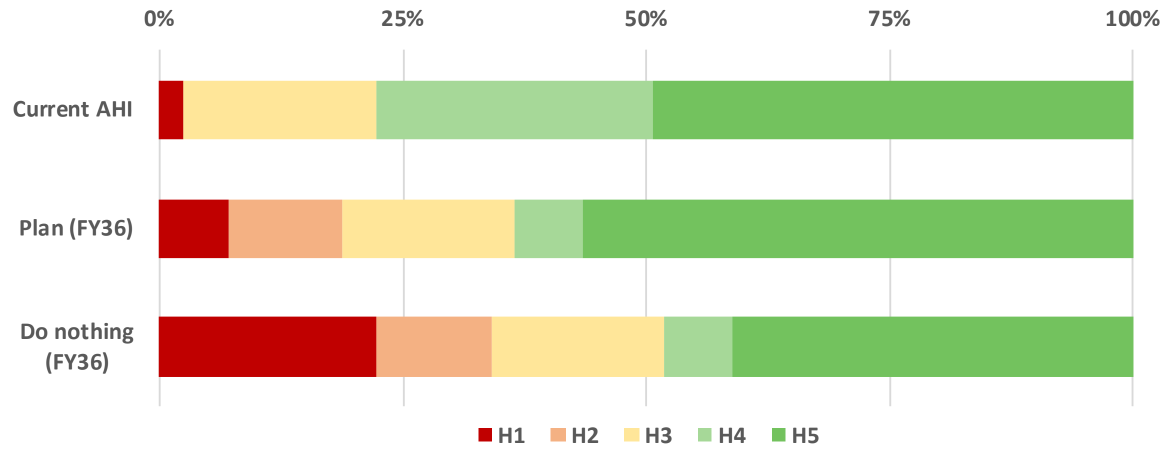


14.6.1.3 Asset health

We estimate the asset health of our power transformers by forecasting the conditional probability of failure of each individual power transformer in each future year given its current age. From this, we can determine an optimal 'need date' for replacement, which is used to classify each power transformer as H1 etc. The figure on the following page sets out an overview of the asset health scores for our power transformers fleet.

[57] Three single phase units combined into a 'bank' are shown as a 3-phase unit. There are two such installations.

Figure 14.35 Asset health – power transformers



The overall fleet is in relatively good health, with two transformers due for replacement (H1). Both have exceeded their 60-year life expectancy, are in poor condition, and are relatively expensive to maintain. These two units have Dissolved Gas Analysis (DGA) results that indicate there have been thermal faults occurring within the unit. The tap selectors have high resistance measured on every second tap position. These DGA results and high resistance measurements confirm that these units are due for renewals.

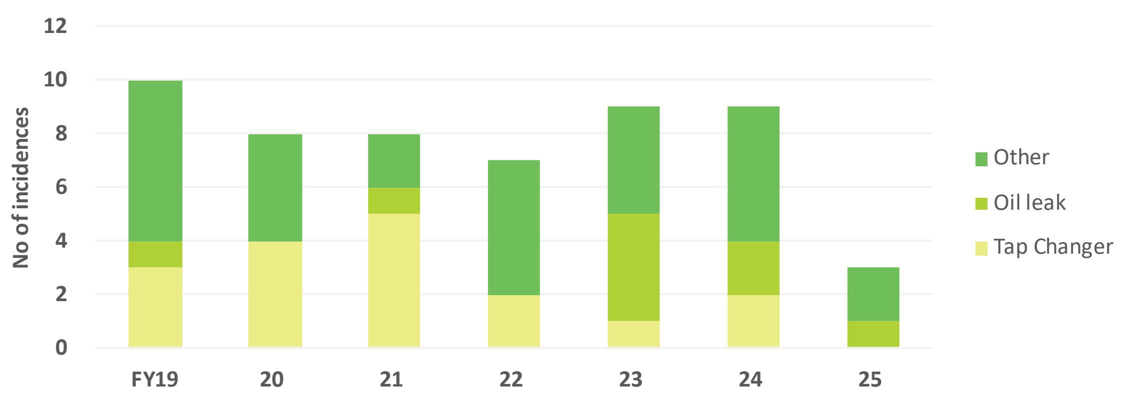
We plan to replace several power transformers during the AMP period as part of major asset renewal projects. Our planned investments will maintain overall health of the power transformers fleet. However, deliverability and cost factors mean that the large number of transformers that will reach end of life in the next decade cannot all be replaced within that time. To manage this, we have prioritised renewals based on probability of failure and other factors, such as whether they have back-feed cover, higher or lower loadings, and coverage by spare units. Those assessed as lower priority will be completed outside the AMP period.

14.6.1.4 Asset performance and risk

We track performance of power transformers based on number of incidences; these are issues we have attended to reactively and which have required corrective action.

The figure below shows the number of incidences over the past seven years.

Figure 14.36 Performance - number of power transformer incidences



There have been a number of tap changer faults in the past, mainly attributable to poor condition. The faults have been trending downwards in recent years as the root causes have been addressed. The 'other' incidents are mostly component failures, such as fan faults, gassing issues (oil), gauges, and temperature sensors. Overall recent performance is stable.

The table below summarises the key risks identified for our power transformers fleet.

Table 14.32 Identified risks and mitigations – power transformers

Risk Area	Description	Mitigations
Network interruption Health and safety Environment	At one site, two power transformers share a bund. If one caught on fire, the oil and/or fire could spread to the other. At other sites, shared roof spaces above transformers would allow fire to spread.	We are assessing options to manage this risk, such as the use of fire containment cells or fire suppression systems.
Network interruption	Some ageing power transformers exhibit deterioration indicators such as corrosion and elevated dissolved gas levels. This increases outage risk under contingency conditions.	Regular inspections and mid-life refurbishment. Replacement programme.
Environment	Some of the older transformers have moderate oil leaks.	Inspections check for oil levels, oil leaks and rust which may cause leaks. Regular inspections and mid-life refurbishment. New transformers have bunding and oil containment.
Environment	Excessive transformer noise.	Investigate complaints and remediate to council limits if required. Acoustic studies and transformer specification.
Network interruption	Major active part failure or major on-load tap-changer (OLTC) failure	Keep unit spare parts once decommissioned, in case of future failures. Preventive maintenance of OLTCs including oil testing and monitoring. N-1 security (two transformers). Replacement programme.

14.6.1.5 Renewal strategy

We assess power transformers replacement need on an individual basis and replace them proactively based on failure likelihood.

We refurbish power transformers when they exceed half their expected life. Undertaking this work means that:

- their operating life is extended, which defers the need for large renewal capex projects
- defects are removed, which means they are less likely to fail, which has a positive impact on network reliability
- the asset is less likely to leak which has a positive environmental impact.

Our service delivery partners have a refurbishment workshop at Papanui zone substation, minimising transportation costs.

Table 14.33 Renewal strategy – power transformers	
Tasks	**Description**
Renewal/refurbishment trigger	Asset health (replacement). Age (refurbishment).
Forecasting approach	We forecast proactive renewal volumes of power transformers using probability of failure and economic models. We forecast refurbishment volumes for power transformers using an age-based approach.
Cost estimation	Tailored estimate (replacement). Volumetric (refurbishment).

14.6.1.6 Renewal forecasting approach

Replacements

We have adopted a conditional probability of failure renewal forecasting approach for our power transformers. This is the probability that the transformer will fail in each future year, given it has survived to its current age. A Weibull distribution is used for this purpose. The Weibull methodology assumes that age is a good proxy for condition and probability of failure, which we consider is the case for power transformers. When the probability of failure reaches a specified threshold, we consider the power transformer due for renewal.

Zone substation works are complex, and it is unusual to replace one type of asset, such as power transformers, in isolation. It is generally more cost effective to replace several assets as part of a broader zone substation renewal project. A combination of power transformers, switchgear, and buildings is common, together with associated cabling, gantries etc.

When renewing assets, we may also take the opportunity to update the zone substation network configuration, further improving security of supply or bringing it up to current standards. There are often many possible options, which we test using economic modelling that considers the cost of implementing the project against its benefits in terms of avoided risk. We capture the findings of the economic model, rationale, and other qualitative assessments in a business case. This approach applies to all major zone substation projects.

Refurbishments

Refurbishment volumes for power transformers are forecast using an age-based approach. We will look to develop a refurbishment index in the future that identifies candidates based on condition, as opposed to age. Costs are estimated using a volumetric methodology, with unit rates based on historical outturns and refurbishments are delivered at a rate that is achievable by the workshop.

14.6.2 Outdoor switchgear

14.6.2.1 Asset overview

Outdoor switchgear is primarily used to control, protect, and isolate electrical circuits. It de-energises equipment and provides isolation points so our service delivery partners can access equipment for maintenance or repairs. Our outdoor switchgear fleet is made up of asset types associated with HV outdoor switchyards, including the following.

- **Outdoor circuit breakers and reclosers**: circuit breakers can interrupt fault currents during system abnormalities and switch load currents during normal routine operation. They provide system protection, isolation, and operating flexibility. We generally classify them by interrupter type; the medium used to extinguish the arc that occurs when the breaker interrupts the flow of current. Our circuit breakers have oil, SF_6, or vacuum interrupters.

- **Disconnectors**: provide isolation points in outdoor switchyard structures. They are mounted on support posts or hung from an overhead gantry. They are mostly manually operated switches, but we have installed motor-operated disconnectors at some sites. Disconnectors are not rated to interrupt load or fault currents.
- **Fuses**: for protection and isolation.
- **Bus-work**: located in the switchyard.

14.6.2.2 Asset population and age

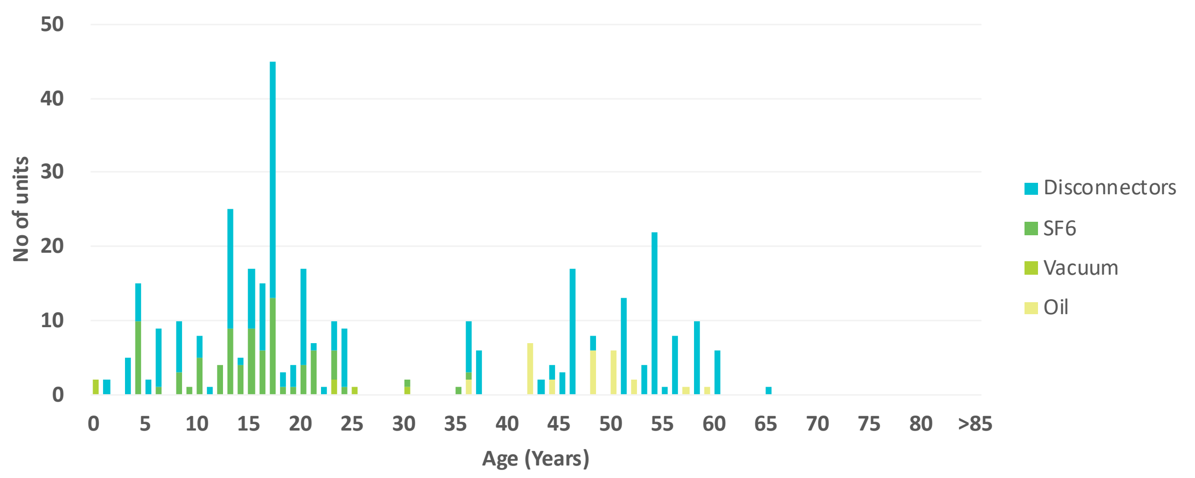
The table below summarises our population of outdoor switchgear by type.

Table 14.34 Population - outdoor switchgear

Asset type	33 kV	66 kV	Expected lifespan
Disconnectors	54	181	50 years
Circuit Breakers	-	-	-
Oil	20	7	40 – 45 years
SF6	0	85	35 years
Vacuum	6	0	45 years
Total	**80**	**273**	

The figure below shows the age profile of our outdoor switchgear fleet. A small number of oil circuit breakers that have surpassed their expected life remain in service. While their longer service life can benefit customers, they have higher maintenance costs, and a higher risk of failure, so we are continuing to replace them, either with new outdoor switchgear, or by converting them to indoor switchgear. More than 25% of our outdoor disconnectors are overdue for replacement based on age.

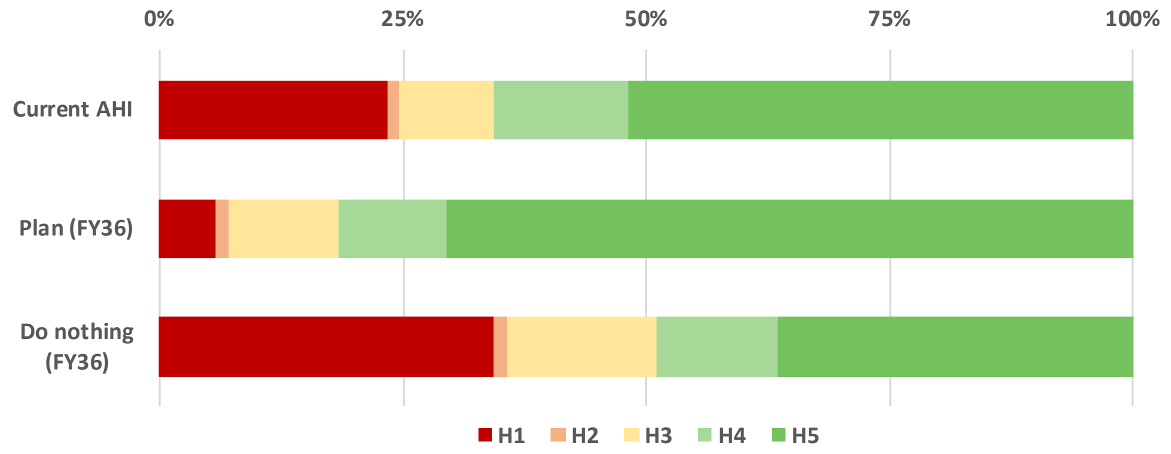
Figure 14.37 Age profiles - outdoor switchgear



14.6.2.3 Asset health

We estimate the asset health of our outdoor switchgear in the same way as we assess the health of our power transformers. Our approach forecasts the conditional probability of failure of each individual circuit breaker or disconnector in each future year given its current age. The figure below sets out asset health scores for our outdoor switchgear fleet.

Figure 14.38 Asset health – outdoor switchgear



Approx. 25% of our 33 kV and 66 kV outdoor switchgear population is at or near end of life as depicted by H1 and H2. These are the oil type circuit breakers and ageing disconnectors. We have identified multiple condition issues with some of the older oil-interrupted 33 kV and 66 kV circuit breakers, including corrosion, gasket and O-ring leaks, and damaged bushings. These issues are consistent with expected age-related deterioration given the nature of their outdoor environment and are being managed through maintenance and factored into our replacement decisions.

Our planned investments will improve our overall outdoor switchgear fleet health, helping to manage the risks associated with failures.

Some outdoor switchgear will be replaced with indoor switchgear. All remaining outdoor oil switchgear will be replaced, as these have exceeded their expected lives, are relatively costly to maintain, and carry a higher risk of failure than the younger SF_6 and vacuum types. Our SF_6 or vacuum outdoor circuit breakers are relatively young with good asset health. Disconnectors which are at end of life will also be replaced. The number of assets requiring renewal within a decade, if our investment is implemented, will reduce significantly.

14.6.2.4 Asset performance and risk

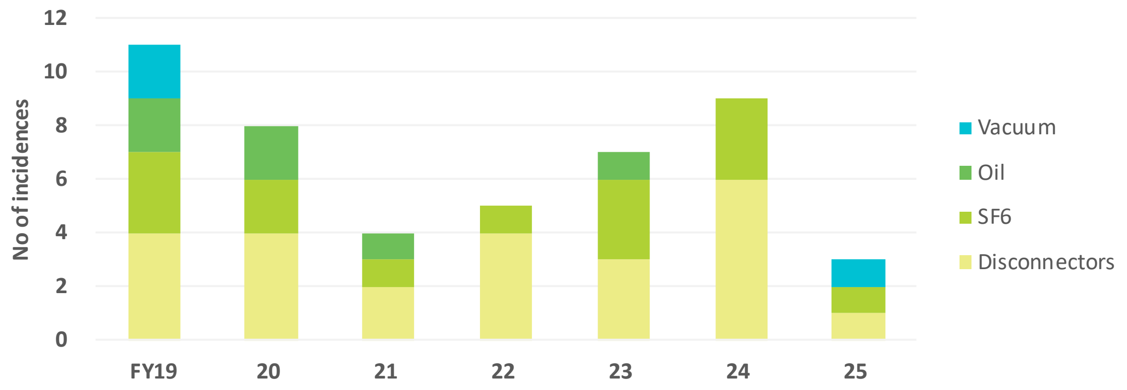
While switchgear failures are uncommon, their occurrence can result in major disruptions for customers and pose serious safety risks to our teams and service delivery partners. Failures can also result in increased damage to equipment during a fault. Incidents are thoroughly investigated to identify the root cause, enabling us to proactively prevent similar events from happening.

Overall performance of our outdoor circuit breakers is satisfactory. Isolated cases of slow trip failures have occurred in some of the older oil circuit breakers. Slow trip failures generally occur due to inactivity of the circuit breaker for long periods. Slow tripping circuit breakers are identified and mitigated through routine maintenance.

Some of our older 33 kV and 66 kV disconnectors are experiencing performance issues and have required servicing or repairs under emergency maintenance. We have a replacement programme for problematic disconnectors.

The figure below shows the number of incidences related to each type of switchgear. Most of the issues relate to disconnectors, such as 'stuck' or rusted operating mechanisms or earth switch components not operating properly. Incidences related to SF_6 circuit breakers are largely gas leaks.

Figure 14.39 Performance - outdoor switchgear



The table below summarises the key risks we have identified for our outdoor switchgear.

Table 14.35 Identified risks and mitigations – outdoor switchgear

Risk Area	Description	Mitigations
Network interruption Health and safety	Ageing insulation such as deterioration of epoxy or resin bonded paper, moisture ingress and loss of or deterioration of insulant (both oil and SF_6). Insulation failure can be catastrophic and potentially damage nearby assets, particularly for oil insulated assets where the risk of fire is increased. Poses a risk to staff where manual operation of switchgear is required. Arc flash risk.	Replacement if ongoing maintenance and refurbishment is not economical or possible. Replacement of 11 kV oil circuit breakers which are ageing and lack spares and support.
Network interruption	We have identified multiple condition issues with some of the older oil-interrupted 33 kV and 66 kV circuit breakers, including corrosion, gasket and O-ring leaks, and damaged bushings.	These issues are consistent with expected age-related deterioration given the nature of their outdoor environment and are being managed through maintenance and factored into our replacement decisions.
Network interruption	Failure to operate during fault conditions, including stuck or rusted operating mechanisms or earth switch components not operating properly.	Corrective maintenance to ensure operating mechanisms are fixed / operating as required. Coordination of protection systems to ensure the provision of backup fault clearing.
Network interruption Health and safety	Arcing fault in oil circuit breaker leading to explosion.	Regular maintenance and remote switching of circuit breakers. Replacement programme.
Health and safety	Arc flash.	Remote operation / switching Maintenance and replacement programmes.
Fraud/theft	Break ins, theft, and vandalism by third parties.	See buildings and grounds mitigations

14.6.2.5 Renewal strategy

We replace most 33 kV outdoor switchgear with indoor switchgear when it reaches end of life. We will replace all our oil-filled outdoor switchgear during the AMP period. We are aiming to improve the health, performance, and safety of our outdoor switchgear fleet over the AMP period.

We also replace outdoor switchgear proactively, prioritised based on risk and consequence of failure. Consequences consider the potential impact on safety, customer service, environmental harm, and cost. We may also prioritise replacements of some circuit breakers for which spare parts are difficult to obtain. Where possible, switchgear is replaced as part of a wider project, as this is cost effective.

Table 14.36 Renewal strategy – outdoor switchgear

Tasks	Description
Renewal trigger	Condition and asset health.
Forecasting approach	We forecast proactive renewal volumes of outdoor switchgear using probability of failure and economic model.
Cost estimation	Tailored estimation.

14.6.2.6 Renewal forecasting approach

We use the same approach for forecasting outdoor switchgear renewals as for power transformers. The expected age at failure used to define the Weibull distribution varies by circuit breaker type: 45 years for vacuum and oil-filled, and 35 years for SF_6 breakers. Outdoor disconnectors have an expected life of 50 years.

14.6.3 Indoor switchgear

14.6.3.1 Asset overview

Our indoor switchgear fleet is made up of individual switchgear panels assembled into a switchboard. The panels contain circuit breakers, isolation switches, busbars, and associated insulation and metering, and protection and control devices. The fleet also includes outdoor switchgear that is housed inside a building.

The insulation/interrupting medium is oil (11 kV only), SF_6, or vacuum, where the latter has lower maintenance requirements than the other types. Some of the modern switchboards are built to internally contain arc flash and are externally vented for additional safety.

Indoor switchgear is generally more reliable than outdoor switchgear because it is not exposed to weather, bird strikes, etc. It has a much smaller footprint than its outdoor equivalent making it a practical solution for situations where space is limited. It also has the advantages of improved operator and public safety, and security.

14.6.3.2 Asset population and age

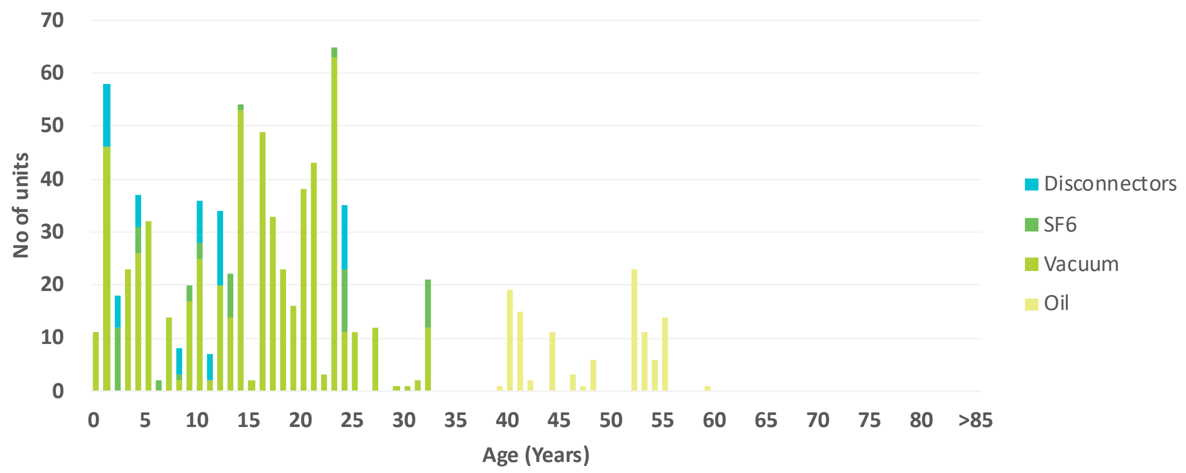
The table below summarises our population of indoor switchgear by type.

Table 14.37 Population - indoor switchgear

Asset type	11 kV	33 kV	66 kV	Total
Disconnectors	0	0	68	68
Circuit Breakers	-	-	-	-
Oil	113	0	0	113
SF_6	9	6	43	58
Vacuum	563	42	0	605
Total	**685**	**48**	**111**	**844**

The figure below shows the age profile of our indoor switchgear fleet.

Figure 14.40 Age profiles - indoor switchgear

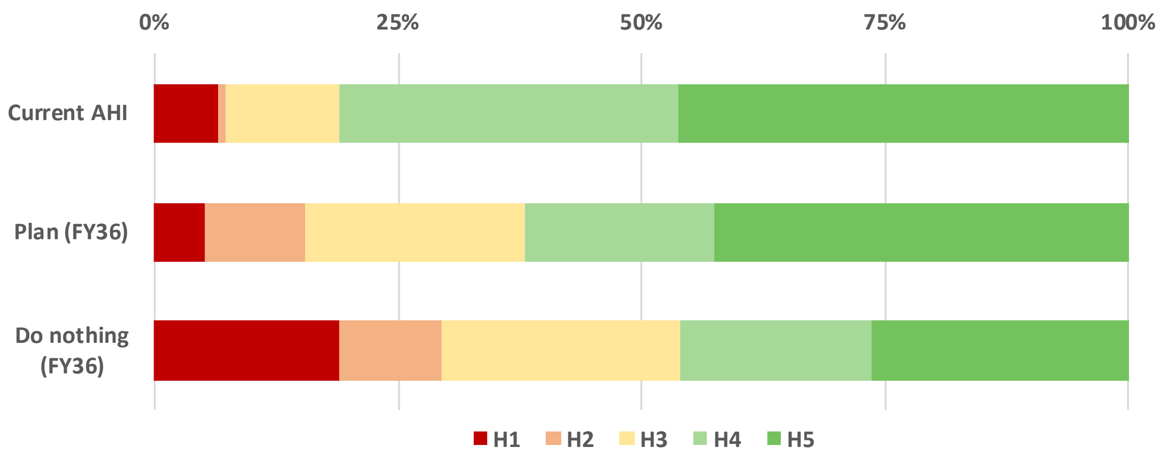


All our older population of indoor circuit breakers are oil-filled, as shown on the right-hand side of the figure above. It is becoming more difficult to obtain spares for these units, so we are progressively replacing them with vacuum types rated for arc fault containment. The latter type requires minimal maintenance and meets modern performance, environmental, and safety standards.

14.6.3.3 Asset health

We use the same approach for assessing the health of our indoor switchgear as for power transformers and outdoor switchgear. This approach is based around the conditional probability of failure of each individual circuit breaker or disconnector in each future year given its current age. From the probability of failure, we can determine an optimal ‘need date’ for replacement, which is used to classify each asset as H1, etc. The figure below sets out an overview of the asset health scores for the fleet.

Figure 14.41 Asset health – indoor switchgear



The assets requiring replacement over the next 10 years (H1 to H3) are mainly the ageing oil-filled switchgear for which availability of spares and specialist skills is becoming an issue. Many of these oil-filled switchgear do not have arc flash protection, nor can they be retrofitted with them. This presents a higher than acceptable worker safety risk should the oil-filled switchgear fail. There is the added risk that the arc flash could be fuelled by oil, making the explosion worse. Our planned investments will replace the majority of this type of switchgear with modern vacuum type switchgear with arc fault containment, protection, and venting. These replacements will be carried out as part of our major asset renewal projects.

By the end of the AMP period, vacuum and SF_6 switchgear will reach the end of their expected lives. However, these types of switchgear are generally lower risk compared to oil-filled switchgear.

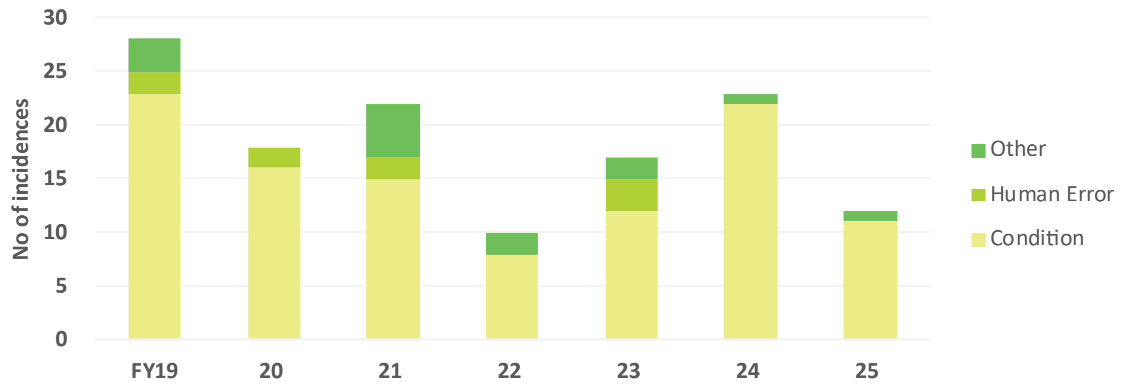
14.6.3.4 Asset performance and risk

Our ageing 11 kV oil-interrupted circuit breakers continue to provide reliable service. However, failure of these assets, while rare, could be catastrophic, with the potential to cause injury to operators. Spares are becoming scarce for some models which is increasing the duration and cost of maintenance or repairs.

For these reasons we are removing all oil-filled circuit breakers as they reach end of life, replacing them with vacuum type circuit breakers rated for arc fault containment. These require minimal maintenance and meet modern performance, environment, and safety standards.

The figure below shows that most incidences are due to condition. Most condition issues relate to our vacuum circuit breakers (some of which are nearing end of life), generally 'stuck' mechanisms, racking issues, and failure to close (the circuit breaker). These require service delivery partners to undertake repairs and realign them.

Figure 14.42 Performance – indoor switchgear



The table below summarises the key risks we have identified for our indoor switchgear fleet.

Table 14.38 Identified risks and mitigations – indoor switchgear

Risk Area	Description	Mitigations
Network interruption Health and safety	Ageing insulation such as deterioration of epoxy or resin bonded paper, moisture ingress and loss of or deterioration of insulant (both oil and SF_6). Insulation failure can be catastrophic and potentially damage nearby assets, particularly for oil insulated assets where the risk of fire is increased. Poses a risk to staff where manual operation of switchgear is required.	Replacement Replacement of 11 kV oil circuit breakers which are ageing and lack spares and support Operational management, Personal Protection Equipment, signage, barriers
Network interruption Health and safety	Arc flash risk	Arc flash protection installed or retrofitted to switchboards with material life. Neutral earthing resisters installed or retrofitted to reduce earth fault levels. Operational management, Personal Protection Equipment, signage, barriers
Network interruption	Older oil-filled 11 kV circuit breakers are an operational risk, as they lack spares and have limited manufacturer support.	Replacement of 11 kV oil circuit breakers which are ageing and lack spares and support

Table 14.38 Identified risks and mitigations – indoor switchgear		
Risk Area	**Description**	**Mitigations**
Network interruption	Failure to operate during fault conditions, including 'stuck' mechanisms, racking issues, and failure to close (the circuit breaker).	Corrective maintenance to ensure operating mechanisms are fixed / operating as required
Environmental	SF_6 leaks	Monthly check of gauges and remediation if required
Network interruption Health and safety	Lightning strike leading to indoor switchgear failure or damage	Install surge arrestors on overhead to cable interfaces

14.6.3.5 Renewal strategy

We replace indoor switchgear proactively based on probability of failure. We combine failure risk with an assessment of the consequence of failure to prioritise replacements.

Consequences consider the potential impact on safety, customer service, and cost. We may also prioritise replacements of switchgear for which spare parts, and skilled workforce to maintain the assets, are difficult to obtain.

We are aiming to improve the health and safety of our indoor switchgear fleet over the AMP period.

Table 14.39 Renewal strategy – indoor switchgear	
Tasks	**Description**
Renewal trigger	Condition or asset health.
Forecasting approach	We forecast proactive renewal volumes of indoor switchgear using probability of failure and economic model.
Cost estimation	Tailored estimate.

14.6.3.6 Renewal forecasting approach

We use the same approach for forecasting indoor switchgear renewals as for power transformers and outdoor switchgear (see Section 14.6.6). The expected age at failure used to define the Weibull distribution varies by switchgear type: 50 years for bulk oil circuit breakers, 35 years for all other types of circuit breaker, and 60 years for indoor disconnectors.

We aim to progressively replace mostly older oil-filled 11 kV circuit breakers that are at, or near, end of life.

14.6.4 Buildings and grounds

14.6.4.1 Asset overview

Our buildings and grounds fleet is made up of zone substation buildings, plus associated sub-systems that house indoor switchgear and secondary systems equipment. There are three permanent building types: tilt slab, concrete block, and brick, together with modular prefabricated buildings.

This fleet also includes zone substation grounds, access ways, and gantries; together with the heating and air conditioning required to keep our assets free of condensation and moisture. Most of our sites have modern A-frame gantries; three sites have older style lattice gantries. Some sites include outdoor yards with switchyard earthing, oil containment, security fencing, access ways, fencing and gates, and gantries.

14.6.4.2 Asset population and age

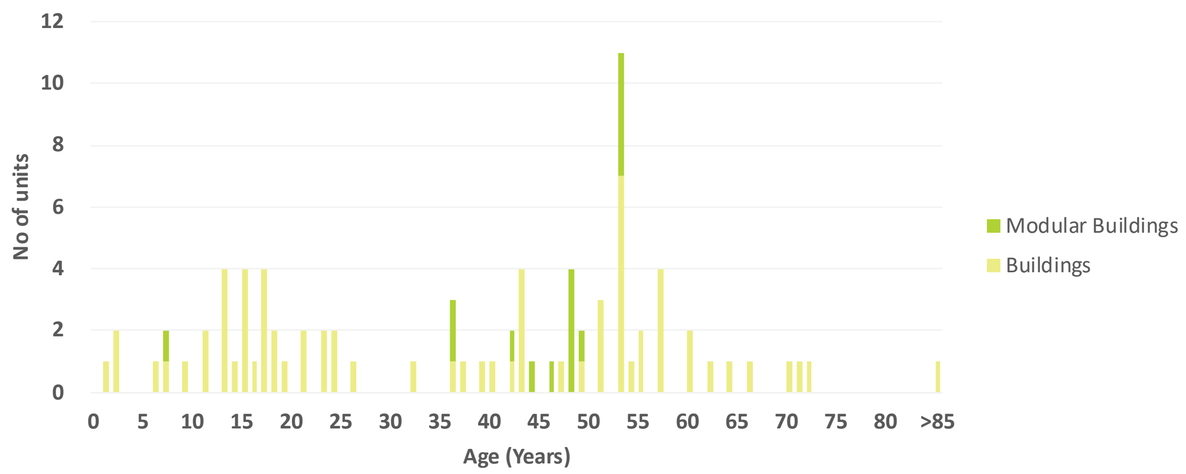
The table below summarises our population of buildings by type. The 85 buildings are spread across 52 zone substations.

Table 14.40 Population - buildings

Asset type	Population
Permanent structures	70
Modular prefabricated buildings	15
Total	**85**

The figure below shows the age profile of our buildings fleet.

Figure 14.43 Age profiles - permanent structures and modular buildings



Most new buildings are a permanent tilt slab construction; this is our preferred building type due to cost effectiveness, fire ratings, and speed of construction.

Renewal of our buildings is normally driven by changes in need, such as converting outdoor to indoor switchgear, or undertaking a major substation rebuild. Aside from this, we aim to maintain our buildings in serviceable condition for as long as they are needed through maintenance and refurbishment. If we are retaining them in service, we aim to improve their seismic resilience to an appropriate level (see subsection below).

14.6.4.3 Seismic Ratings

Seismic assessments and upgrades of some of our zone substation buildings were completed prior to, or in the few years following, the Canterbury earthquakes. These involved upgrading those buildings to at least 67% of the new building standard (NBS) for IL4 buildings.[58]

Orion's standard is to improve buildings to at least 67% of the NBS for IL4 buildings, as these buildings are essential to post-disaster recovery and we are in a high seismic risk area.

However, a considerable number of our zone substation buildings remain below 67% of the NBS, with one site assessed at below 30% of the NBS. We are currently investigating what works are required to bring these buildings up to standard. In some cases, planned zone substation upgrades will impact the need for buildings, such as where the existing building is not fit for housing modern indoor substation equipment. When combined with the need for upgrades to meet weathertightness and seismic

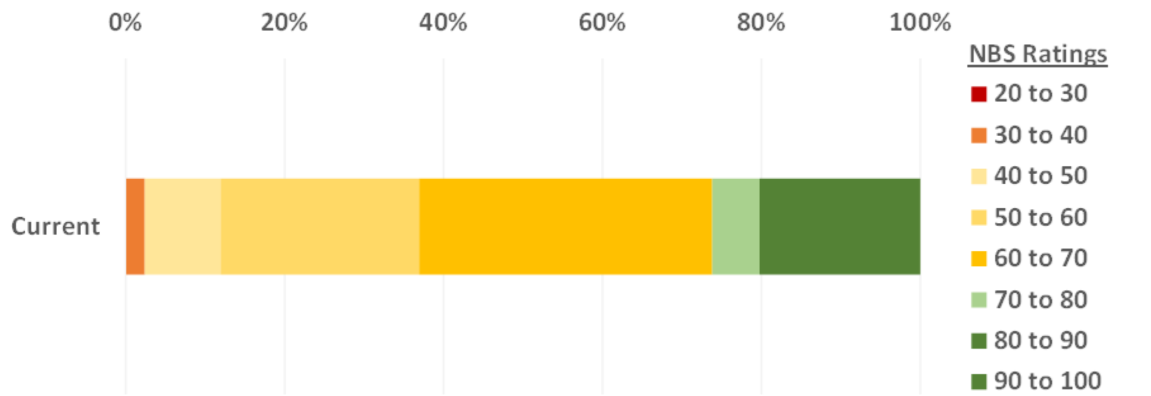
[58] IL4 refers to Importance Level 4 which applies to essential buildings, including lifeline infrastructure. The importance levels are set out in the Building Code. As we are in a high seismic risk area, we aim to improve all our zone substation buildings to at least 67% of the NBS for IL4 buildings. The New Zealand Society for Earthquake Engineering considers this an acceptable seismic risk, and it is often adopted by lenders and insurers, as well as being the standard used by Wellington Electricity, which also operates in a location deemed to have high seismic risk.

standards, the cost-effective solution may involve replacing old buildings with modern, fit-for-purpose permanent buildings as part of the primary asset renewals.

We also consider the condition and need for our other buildings and grounds assets. While zone substation upgrades are generally driven by primary equipment needs, it is cost effective to complete other works that are due as part of the wider project.

The figure below sets out the seismic ratings of our zone substation buildings, i.e. the percentage of the NBS for IL4 buildings. Nearly half of our buildings are currently below 67% of the NBS for IL4 buildings, so will be remediated, or replaced, as part of wider primary plant renewal work.

Figure 14.44 NBS scores – zone substation buildings



14.6.4.4 Asset performance and risk

The reliability of the equipment within the substation is not impacted by the buildings or housings, providing they are kept secure and weathertight, and their internal temperature and humidity is maintained within suitable operating limits. We rigorously control security and entry to our substations, including the buildings, with regular monitoring of site security.

In general, our zone substation buildings are well designed and have performed well. However, the modular buildings that contain our 11 kV zone substation circuit breakers and control equipment (mostly installed prior to 1995) are prone to moisture ingress and high humidity, and rodent ingress. Where indoor switchgear replacement is planned for such buildings, we are also replacing the building.

The table below summarises the key risks we have identified for our buildings and grounds fleet.

Table 14.41 Identified risks and mitigations – buildings and grounds

Risk Area	Description	Mitigations
Network interruption	Water ingress into buildings can damage our assets, e.g. through flooding or leaks due to deteriorated seals.	Regular inspections, and condition assessments Repair if cost effective. Replacement of buildings that are not watertight is often cost effective as part of primary asset replacement projects. For new zone substations, or major works at zone substations, we design the substation civil works to the latest standard for flooding.
Network interruption	High internal temperature and humidity can damage our assets.	Regular inspections and condition assessments. We are implementing air conditioning retrofits, where practical, to control temperature and prevent condensation. We would also install new, or retrofit, heat pumps and insulation as part of major works or when they fail.

Table 14.41 Identified risks and mitigations – buildings and grounds

Risk Area	Description	Mitigations
Fraud/theft	Break ins, theft, and vandalism by third parties.	Upgrade site security with double fencing at zone substations (boundary and security fencing), security cameras at problem sites, and appropriate bollards and access controls. Replaced all locks with standardised high security locks, providing controlled access. Public safety campaign in relation to third parties tampering with our network.
Network interruption	Modular buildings in particular are vulnerable to rodent ingress. They eat wires and/or are burned by the high voltage, potentially causing outages, short circuits etc.	Where indoor switchgear replacement is planned for these buildings, we also replace the building.
Network interruption Health and safety Environment	Equipment catching fire inside the building	Fire detectors, alarms, extinguishers.
Network interruption	Buildings need to be weather tight and well maintained, otherwise the buildings can fail and equipment is exposed to the elements.	Regular visual inspections and condition assessments. We have completed roof replacement programmes for buildings with deteriorating coverings. Repair if cost effective. Replacement of buildings is often cost effective as part of primary asset replacement projects.
Network interruption Health and safety	A considerable number of our zone substation buildings remain below 67% of the NBS, with one site assessed at only 30% of the NBS, which could leave them vulnerable to seismic activity.	We are currently investigating the works needed to bring these buildings up to standard. In some cases, planned zone substation upgrades will impact the need for buildings. The cost-effective solution may involve replacing old buildings with modern, fit-for-purpose permanent buildings as part of primary asset renewals.
Health and safety	Inadequate switchyard earthing can lead to an increase in potential 'step or touch' hazards, putting our staff and service delivery partners at risk of injury.	Earthing of equipment. Periodic earth grid testing. Equipment inspections.
Health and safety	Inhalation of asbestos can cause serious harm to our staff and service delivery partners.	Asbestos survey undertaken. Asbestos register. Hazards identified and labelled. Containment or removal by qualified specialist contractor(s). Mandated risk assessments for works in and around asbestos.
Health and safety Financial loss	Land contamination and Hazardous Activities and Industries List (HAIL) sites. Unexpected discovery of contaminated land issues not only affect health and safety but affect project costs significantly and could cause budget blowouts as these issues typically require costly and appropriate disposal.	Continually update our information database on HAIL sites. Undertake soil sampling tests when detailed design work is carried out for each zone substation.

14.6.4.5 Renewal strategy

For full building replacements, the works are generally driven by replacement of other primary assets and are grouped with them in major projects. For example, several of our modular zone substation buildings are likely to be unsuitable for installing new switchgear as they are not weathertight or rodent proof. The dimensions of some older buildings are insufficient in certain cases. These buildings will be replaced as part of the switchgear renewal. Other buildings and grounds work may also be carried out as part of identified projects, for example, gantry replacement or refurbishment.

Work that is not grouped into an identified project is known as ‘minor works’. Our preventive maintenance inspections identify building components in need of repair or replacement. In recent years we have had several of these programmes running to address risks and manage the condition of our buildings and grounds, including roof refurbishments, fencing upgrades to improve security, and replacing poor condition lattice-type gantries.

In each case the need for the work is based on individual assessment and prioritisation.

Table 14.42 Renewal strategy – buildings and grounds

Tasks	Description
Renewal trigger	Condition – for building elements such as roofing (minor building works) Obsolescence – primarily driven by a change in building use, such as an increase in the footprint needed for new assets Seismic requirements
Forecasting approach	We forecast proactive renewal volumes of minor building works using base-trend
Cost estimation	Volumetric

14.6.4.6 Renewal forecasting approach

We have adopted a base-trend renewal forecasting approach for our minor buildings and grounds works, i.e. work that is not part of major asset renewal projects. This work could include tasks such as switchyard metalling, or replacement of fences, gates, and security/access systems, minor seismic works, reroofing, or replacement of gantries. Our forecasting assumption is that in future years expenditure on this type of work will be similar to the level of work in FY25.

Expenditure on significant building replacements or refurbishment work is forecast as part of major asset renewal projects. Detailed business cases are developed for those projects. In addition, standalone seismic reinforcements will be carried out under the Reliability, Safety and Environment portfolio and are also excluded from this forecast.

14.6.5 Ancillary equipment

14.6.5.1 Asset overview

Our ancillary equipment asset fleet is made up of equipment in our zone substations that does not fit into one of the previous categories. Currently this only includes our load management, which includes ripple controller, ripple transmitter, and coupling cells.

We use ripple injection plant to cost effectively manage load during peak demand periods, minimising transmission charges and deferring the need for network investment. Ripple injection plant also controls street lighting. It works by injecting a carrier frequency with a digital signal into our network, which is acted upon by relays at the consumer connection. The relays on our network are owned by retailers, except for those used for streetlighting control.

14.6.5.2 Asset population and age

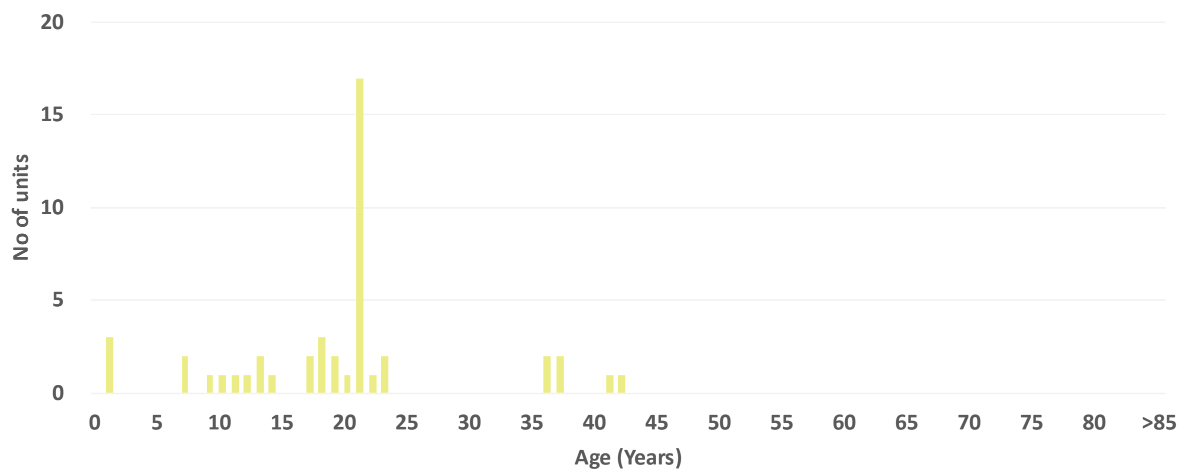
The table below summarises our population of ancillary equipment.

Table 14.43 Population – ripple injection plant (number of injection plants)

Voltage injected at	175 Hz	315 Hz
11 kV	27	12
33 kV	0	5
66 kV	2	0
Total	**29**	**17**

The figure below shows the age profile of our ancillary equipment fleet. Ripple injection plant has an expected life of 30 years. Some have exceeded their expected lives and are due for replacement. The ripple controller/remote terminal unit and transmitters (not shown in the figure below) are also at end of life.

Figure 14.45 Age profiles – ripple injection plant

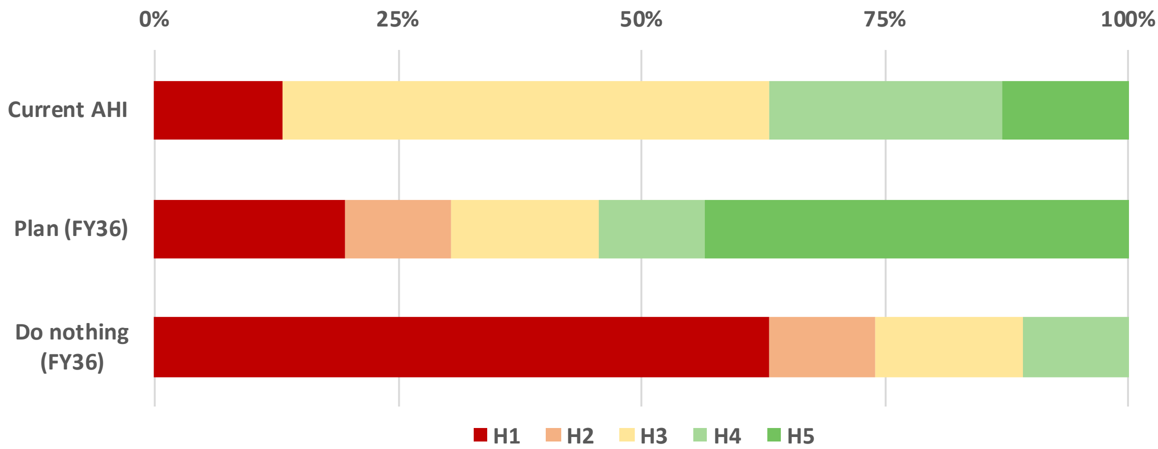


14.6.5.3 Asset health

We manage the condition of our ripple injection plant through a regime of inspections and component replacement, where possible.

The figure below sets out asset health scores for our ancillary equipment fleet.

Figure 14.46 Asset health – ancillary equipment



Based on their expected lives, more than half of our ripple injection plant is due for replacement within the next decade. Our ageing fleet include static frequency converters, which are prone to failure and are now due for replacement. Our replacement plan aims to maintain overall health of the fleet.

14.6.5.4 Asset performance and risk

Generally, our load management systems run at 100% reliability, and incidents affecting operation at critical times are rare.

The table below summarises the key risks identified for our ancillary equipment fleet.

Table 14.44 Identified risks and mitigations – ancillary equipment

Risk Area	Description	Mitigations
Network interruption	We have some electronics issues with the static frequency converters (the ripple transmitter) in the ripple injection system, which are prone to failure with age	Replace as they reach the end of expected life.
Network interruption	Ripple injection plant failure - lack of spares and the capability to maintain them	Replace as they reach the end of expected life

14.6.5.5 Renewal strategy

We replace our ripple injection plant based on age and obsolescence; lack of spares and capability to maintain them.

Table 14.45 Renewal strategy – ancillary equipment

Tasks	Description
Renewal trigger	Age and obsolescence
Forecasting approach	We forecast proactive renewal volumes of ancillary equipment using their age
Cost estimation	Volumetric

14.6.5.6 Renewal forecasting approach

We have adopted an age-based modelling approach to forecast ripple injection plant renewal. This plant has an expected life of about 30 years. This results in a variable forecast as the equipment was installed in clusters. We install replacement equipment, where possible, as part of wider zone substation works.

14.6.6 Zone substation forecasting approach

Major asset renewal projects

We have adopted a conditional probability of failure renewal forecasting approach for our power transformers, outdoor switchgear, and indoor switchgear. This reflects the failure probability of an asset in each future year, given it has survived to its current age. A Weibull distribution is used for this purpose. The Weibull methodology assumes that age is a good proxy for condition and probability of failure with age related adjustment factors being applied to capture known departures from expected asset lives.

When we replace zone substation equipment, we may also seismically reinforce or replace the building that the equipment is housed in; these replacements are usually grouped together in major projects. Full building replacements may occur where building dimensions are insufficient for the new equipment, or if the buildings are not weathertight or rodent proof.

We coordinate zone substation and secondary systems renewals work to align our work programmes and reduce our costs and impact on customers.

We also review all of our zone substation major asset renewal projects to optimise the project timings across asset fleets, e.g. if switchgear and transformer replacements are both required at the same zone substation within a certain timeframe they are undertaken together. Where major growth projects are expected to occur within a similar period as renewal projects, at the same zone substation, those projects will be coordinated to reduce overall project costs, planned outages, and the impact on customers.

We develop a business case for each major asset renewal project including options analysis and qualitative risk and strategic assessments. This involves assessing each option's capital costs and benefits. Options may vary from like-to-like replacement to a new network configuration. A preferred option is selected and becomes the basis for the forecast for that project.

Zone substation programmes

Power transformer refurbishments are forecasted based on when they reach mid-life taking into account condition, performance, and other factors as relevant.

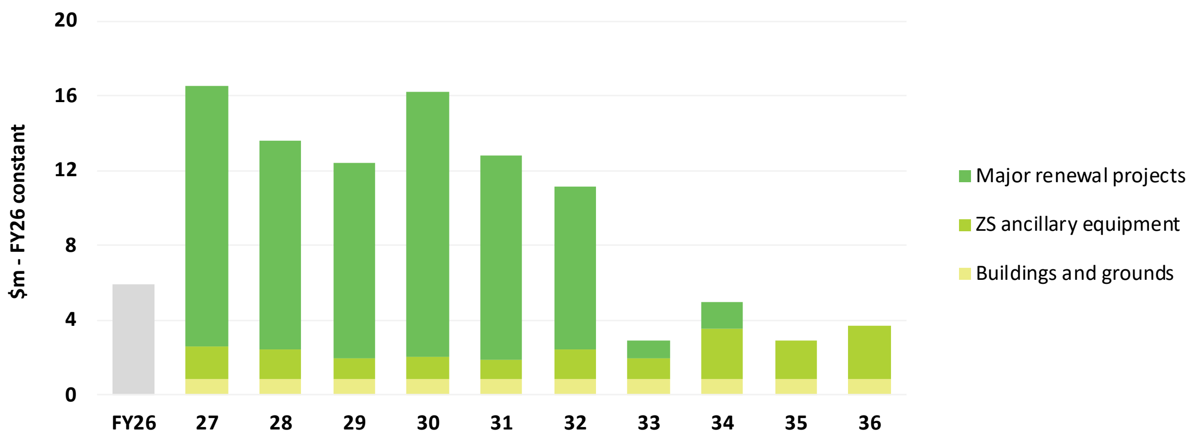
An age-based modelling approach is used to forecast ancillary equipment (ripple plant) renewals. We are also initiating a proactive refurbishment programme.

We use a trending approach to forecast buildings and grounds minor works, this reflects that this expenditure tends to be on recurring works, for example refurbishing buildings and replacing fencing.

14.6.6.1 Zone substations capex forecasts

The following figure shows our forecast capex over the AMP period for zone substation major renewal projects and renewals programmes.

Figure 14.47 Planned zone substation renewals capex



Our zone substation major renewal projects spend is made up of several projects (see Appendix E for further details). These collectively address worker safety risks, primary plant failure risk, poor seismic performance of buildings, emerging constraints and potential reliability risks. These projects are concentrated in the near to medium term as they present a higher than acceptable risk profile. Our zone substation renewal programmes continue throughout the AMP period and are generally stable with some additional ancillary works later in the period.

14.7 Distribution switchgear

Switchgear is a collective term for all types of switches used to control, protect, isolate, and configure our electricity network. We primarily use switches and circuit breakers.

Switches are used to de-energise equipment and provide isolation points so our service delivery partners can access equipment to carry out maintenance or emergency repairs.

Circuit breakers can both interrupt fault currents during system abnormalities and switch load currents during normal routine operation. They are strategically placed in the network to meet requirements for system protection, isolation, and operating flexibility.

This section outlines the asset fleets which make up the distribution switchgear asset class:

- pole mounted switchgear
- pole mounted fuses
- ground mounted switchgear
- enclosures
- ancillary equipment.

14.7.1 Pole mounted switchgear

14.7.1.1 Asset overview

Our pole mounted switchgear fleet is made up of three types:

1. **Line circuit breakers**: these are pole mounted devices installed in strategic locations on the 11 kV network to improve reliability by providing line reclosing and isolation for a portion of a feeder. Newer models have remote control capability, which will allow for future automatic power system restoration. Line breakers are more costly than other types of pole mounted switchgear, and require more maintenance, but unlike the other types, can interrupt fault currents.
2. **Air-break isolators (ABIs)**: these are used on our rural overhead network (33 kV and 11 kV). They are simple hand-operated devices operated in no-load conditions, which are used for fault restoration, isolating plant for maintenance, or reconfiguring the network for repair. We no longer install ABIs.
3. **Line switches**: these are used for switching under normal load conditions (allowing for sectionalising the network) but not for interrupting high fault currents. They are rated at 630A with a vacuum load breaking switch. They are installed to be operated on-site by hot-stick or remote operation.

14.7.1.2 Asset population and age

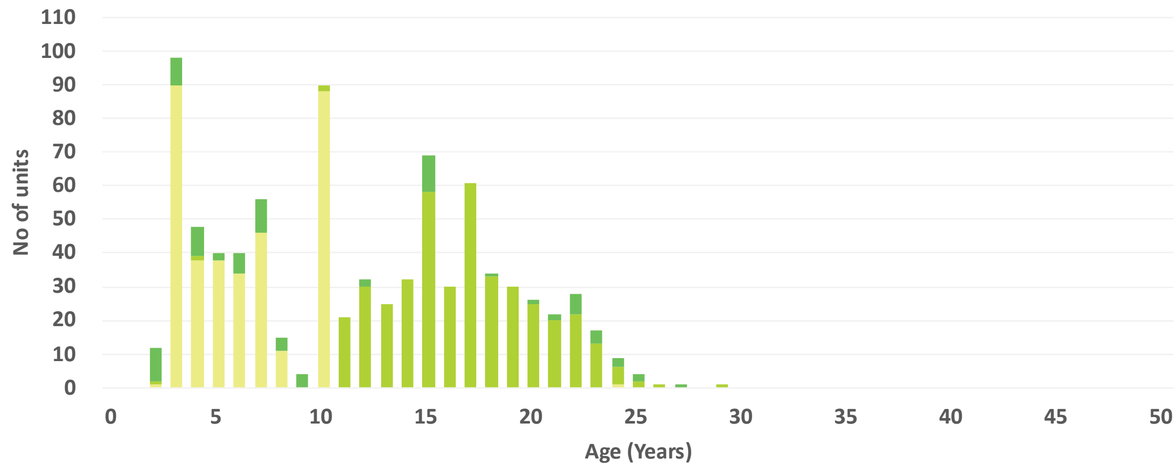
The table below summarises our population of pole mounted switchgear by type.

Table 14.46 Population - pole mounted switchgear

Asset type	Population (approx.)	Expected lifespan
Line circuit breakers (vacuum)	86	50 years
Air-break isolators	413	45-50 years, depending on type
Line switches	347	45 years
Total	**846**	

The figure on the following page shows the age profile of our pole mounted switchgear fleet. Most of our pole mounted switchgear is well inside its expected life.

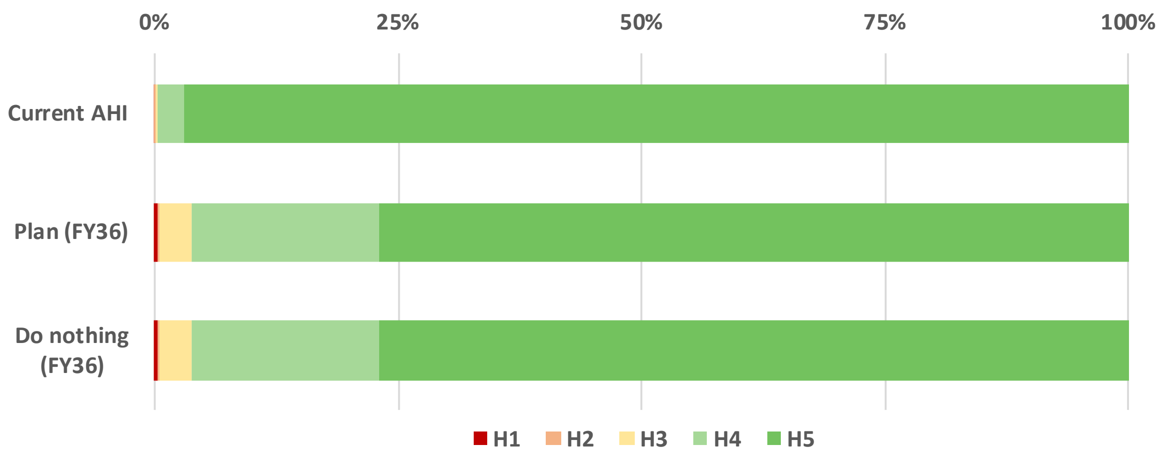
Figure 14.48 Age profiles - pole mounted switchgear



14.7.1.3 Asset health

We have adopted an age-based Repex approach to derive future asset health. Our AHI for pole mounted switchgear reflects expected remaining life. The figure below sets out asset health scores for our pole mounted switchgear fleet.

Figure 14.49 Asset health – pole mounted switchgear

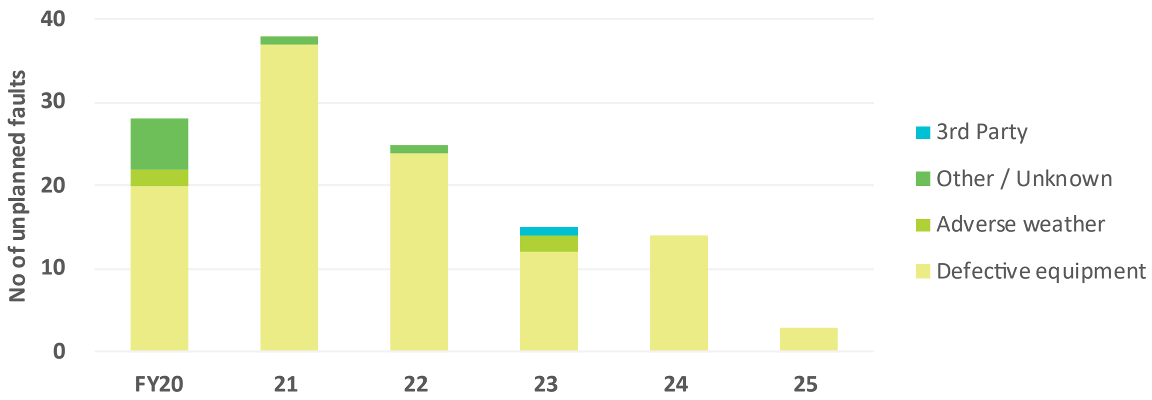


Line switches are new assets and, so far, the fleet shows no significant degradation, defects, or type issues. Most of our ABIs and line circuit breakers are in serviceable condition and well within their expected lifetimes, so the overall volume of assets needing replacement over the AMP period (H1 to H3) is small.

14.7.1.4 Asset performance and risk

Our 33 kV ABIs are routinely maintained and performing as expected. We were seeing a high failure rate for one model of 11 kV ABI, due to faulty insulators cracking, resulting in flashovers causing outages. We have progressively replaced this model with line switches or line circuit breakers, the result being a downward trend in faults as shown in the figure below. Our line switches are now relatively new and are performing well, with no defects or lifecycle related failures to date.

Figure 14.50 Performance – pole mounted switchgear



The table below summarises the key risks we have identified for our pole mounted switchgear.

Table 14.47 Identified risks and mitigations – pole mounted switchgear

Risk Area	Description	Mitigations
Network interruption	Failure to operate due to stuck or rusted operating mechanisms	Regular inspections and corrective maintenance to ensure operating mechanisms are fixed / operating as required
Network interruption	Water ingress causing seizing up of moving parts	Regular inspections and corrective maintenance to ensure operating mechanisms are fixed / operating as required
Environmental	SF_6 leaks	Regular inspections and corrective maintenance to replace deteriorated seals

14.7.1.5 Renewal strategy

Having completed a programme to address type issues with ABIs, we now only replace pole mounted switchgear assets when they are damaged or fail. Due to the young age of the fleet, we do not anticipate any renewals will be needed throughout the AMP period.

Table 14.48 Renewal strategy – pole mounted switchgear

Tasks	Description
Renewal trigger	Condition Failure or damage
Forecasting approach	We forecast proactive renewal volumes of pole mounted switchgear using Repex
Cost estimation	Volumetric

14.7.1.6 Renewal forecasting approach

We use a Repex renewal forecasting approach for pole mounted switchgear, using a life expectancy of 50 years for line circuit breakers, line switches, and Electropar ABIs, and 45 years for other ABIs.

14.7.2 Pole mounted fuses

14.7.2.1 Asset overview

Our pole mounted fuses fleet is made up of three types:

1. **Drop out fuses**: pole-mounted switch-like assemblies designed to protect equipment, such as transformers or feeders, from overloads or short circuits by 'dropping out' or falling open when a fault is detected. This isolates the affected part of the system to prevent further damage and allow for easier repairs. New 'sparkless' fuses are installed in some locations.
2. **Section fuses**: provide isolation of a faulty section of network by simply burning out. This type of fuse is used to minimise the number of customers affected by a fault.
3. **Solid links**: solid bars used in place of a fuse, where no overcurrent protection is needed. They are manually operated to provide isolation.

14.7.2.2 Asset population and age

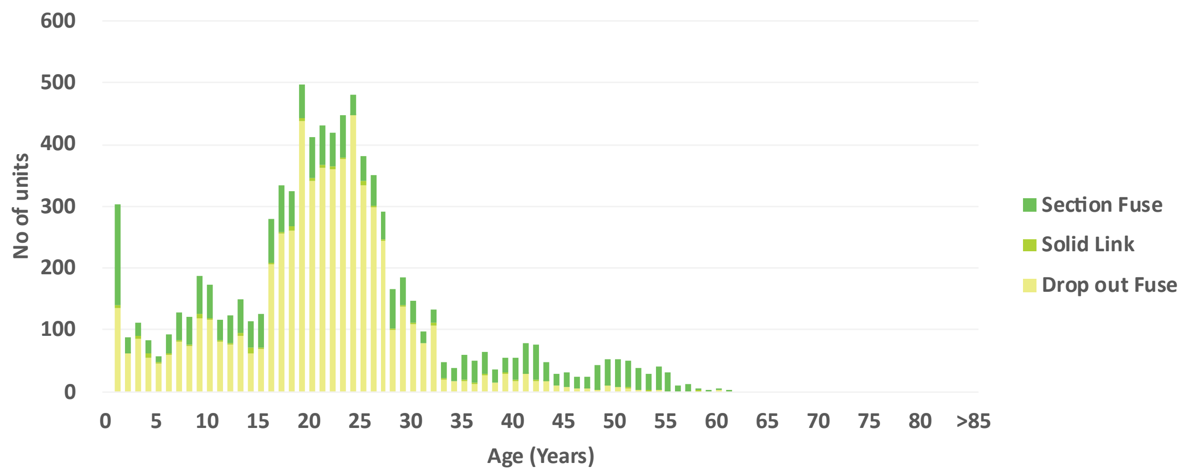
The table below summarises our population of pole mounted fuses fleet by type.

Table 14.49 Population - pole mounted fuses

Asset type	Population (approx.)	Expected lifespan
Drop out fuses	5,950	45 years
Section fuses	2,350	50 years
Solid links	140	50 years
Total	**8,440**	

The figure below shows the age profile of our pole mounted fuses fleet. The age distribution indicates that the numbers requiring replacement will remain relatively low over the next decade.

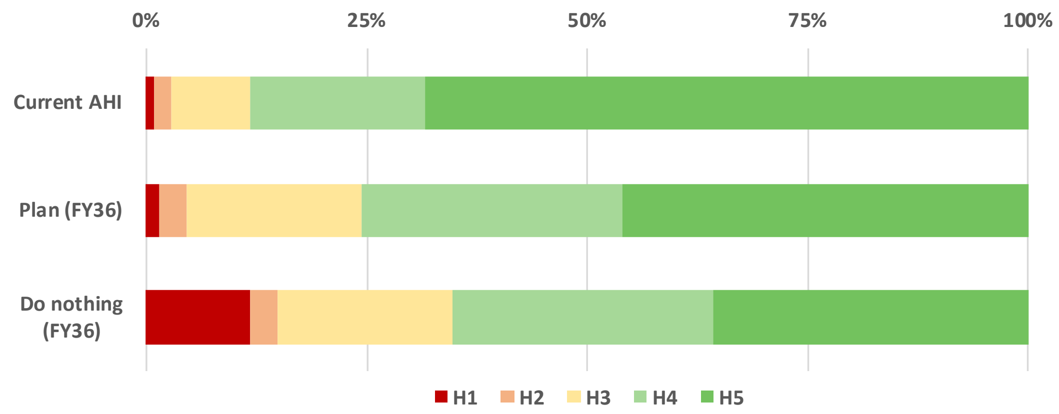
Figure 14.51 Age profiles - pole mounted fuses



14.7.2.3 Asset health

We have adopted an age-based Repex approach to derive future asset health, as described for pole mounted switchgear in the previous section. The figure below sets out an overview of the asset health scores for our pole mounted fuses fleet.

Figure 14.52 Asset health – pole mounted fuses

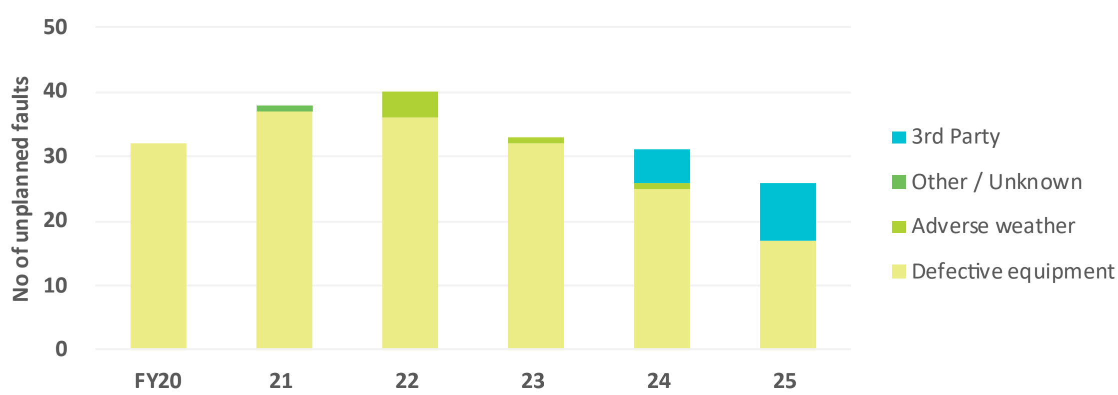


The overall volume of assets currently needing replacement over the AMP period (H1 to H3) is relatively small. Renewal programme will maintain overall health throughout the AMP period by replacing deteriorated or poor condition fuses and when they are found to be inoperable or fail in service.

14.7.2.4 Asset performance and risk

The overall performance level is satisfactory. During FY20-22 we had an issue with the operation of older fuses; many had rusted bolts so when the fuse operated it could not be put back on, so the whole fuse assembly had to be replaced. These replacements have resulted in fewer defective equipment faults.

Figure 14.53 Performance – Pole mounted fuses



The table below summarises the key risks we have identified for our pole mounted fuses.

Table 14.50 Identified risks and mitigations – pole mounted fuses

Risk Area	Description	Mitigations
Network interruption Health and safety	When the fuse operates the molten metal can drop on the ground; if the ground is dry and has flammable material such as dry grass, there is a high risk of fire.	We are replacing fuses in rural/dry grass areas, such as the Port Hills, with 'sparkless' fuses to minimise risk of fires starting due to fuse operation.

14.7.2.5 Renewal strategy

We have historically replaced pole mounted fuses either in response to a defect identified during inspection, or upon failure due to defect or third-party incidents. Defects include cracked insulators or corroding parts. We do not collect condition data on these assets. This approach will continue through the AMP period.

In addition to this, we have begun a programme of work to replace fuses in rural areas/areas with dry grass, such as the Port Hills, with sparkless fuses, which are designed to minimise fire risk from fuse operation.

Table 14.51 Renewal strategy – pole mounted fuses

Tasks	Description
Renewal trigger	Condition Failure Fire risk – replace fuses in certain locations with sparkless fuses
Forecasting approach	We forecast proactive renewal volumes of pole mounted fuses using: • Repex • Base rolled forward – sparkless fuse renewals programme
Cost estimation	Volumetric

14.7.2.6 Renewal forecasting approach

We have adopted a Repex forecasting approaches for pole mounted fuses (apart from sparkless fuses which are trended). We used a life expectancy of 45 years for dropout fuses and 50 years for section fuses and solid links. Sparkless fuses tend to cost more than standard drop out fuses due to their advanced arc-quenching technology (which require more costly materials) and improved safety features.

14.7.3 Ground mounted switchgear

14.7.3.1 Asset overview

Ground mounted switchgear is generally associated with our underground cable network. Ground mounting also allows us to install larger units. Our fleet is made up of three types:

1. **Ring Main Units (RMUs)**: fully enclosed, metal-clad 11 kV switchgear that may be installed in a (distribution) substation or outdoors, to provide connections, and switching and isolation functionality to distribution transformers. Typically, they have load-break switches and/or vacuum circuit breakers, and with motorisation and addition of electronic protection relays, they can be fully automated. Since 2006, new RMUs have been rated for internal arc flash containment.
2. **Magnefix Switching Units (MSUs)**: manually operated, quick-make, quick-break design with all live parts fully enclosed in cast resin. They are compact and have a substantially smaller footprint compared to other switchgear options, so are the predominant type installed in our 11 kV cable distribution network. New installs have cables trifurcated to avoid cable failure affecting the MSU.
3. **Indoor switchgear (IDS) panels**: used to protect the distribution network. Older types use oil or SF_6 as the interruption medium; after 1992 they are all vacuum type.

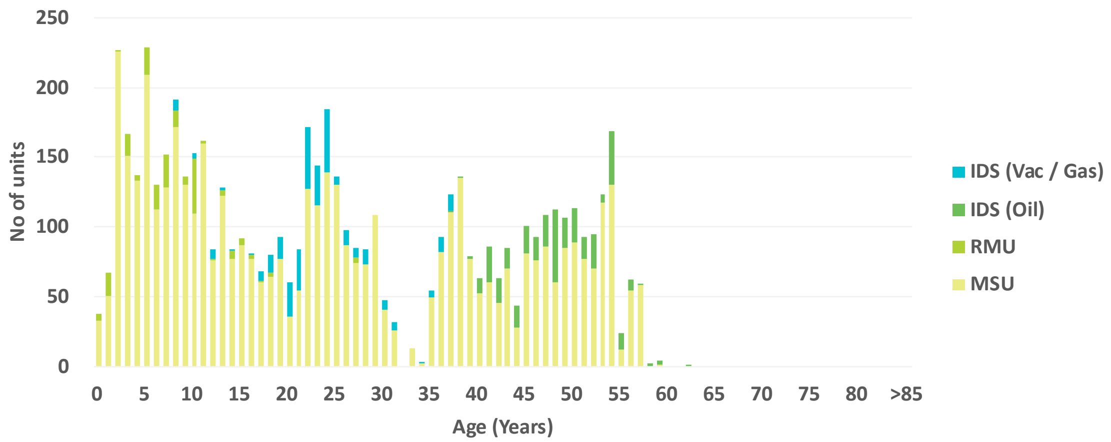
14.7.3.2 Asset population and age

The table below summarises our population of ground mounted switchgear by type.

Table 14.52 Population - ground mounted switchgear		
Asset type	**Population (approx.)**	**Expected lifespan**
11 kV Magnefix Switching Units	4,990	60 years
11 kV Ring Main Units	190	45 years
Indoor switchgear panels (oil)	360	50 years
Indoor switchgear panels (vacuum/SF_6 gas)	300	45 years
Total	**5,840**	

The figure below shows the age profile of our ground mounted switchgear fleet.

Figure 14.54 Age profiles - ground mounted switchgear



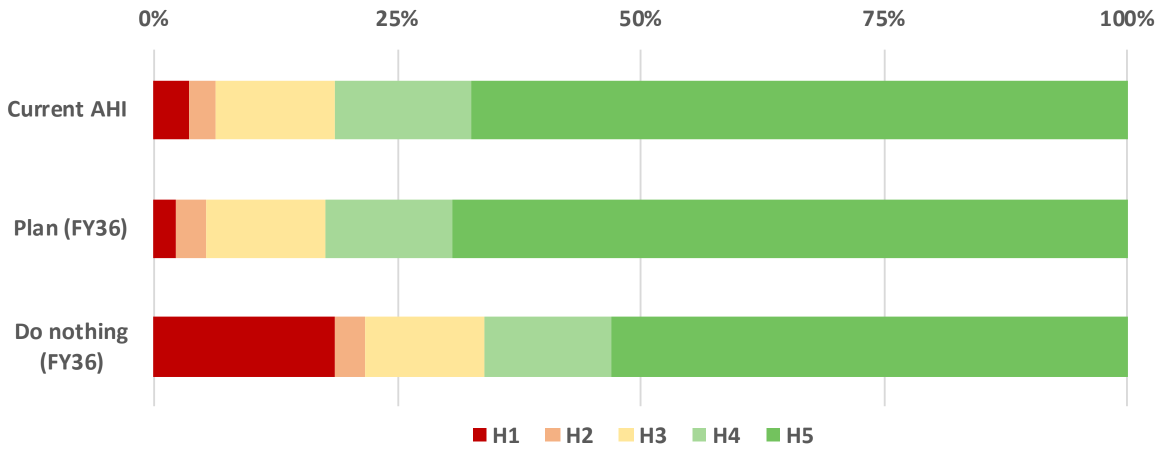
Many of our indoor switchgear panels have, or will soon, exceed their life expectancy, increasing the risks of failure and arc flash (safety), and increasing maintenance costs. A sizable proportion of the large MSU population is nearing expected end of life, which has a substantial impact on the renewals needed to maintain the health of the fleet. We are also replacing RMUs that are at end of life, or which have safety drivers, these latter RMUs make up most of the RMU population.

14.7.3.3 Asset health

We have adopted an age-based Repex approach to derive future asset health for our ground mounted switchgear. Our AHI for these assets reflects expected remaining life. The life expectancy is represented by a distribution as this approach is more robust than simply assuming that equipment fails at a particular age.

The figure below sets out an overview of the asset health scores for our ground mounted switchgear fleet. The figure accounts for RMUs with safety type issues.

Figure 14.55 Asset health – ground mounted switchgear



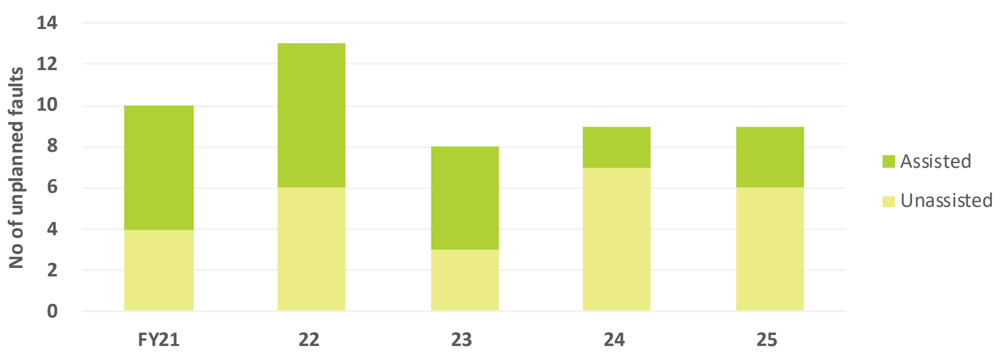
Our current level of assets with a H1 score mainly comprise the safety type issue RMUs, which are both a public and worker safety risk. Over the AMP period, we are planning to phase these type-issue RMUs out, as well as replacing other ground mounted switchgear. Oil-filled indoor switchgear panels will be replaced with RMUs and we will prioritise unfused MSUs over the AMP period, resulting in a reduction in safety risks and improved overall fleet health.

14.7.3.4 Asset performance and risk

In-service failure of ground mounted switchgear can be a significant safety issue as it can expose the public and personnel to electric shock or arc flash. Failure can also affect supply to consumers, so we aim to replace before failure.

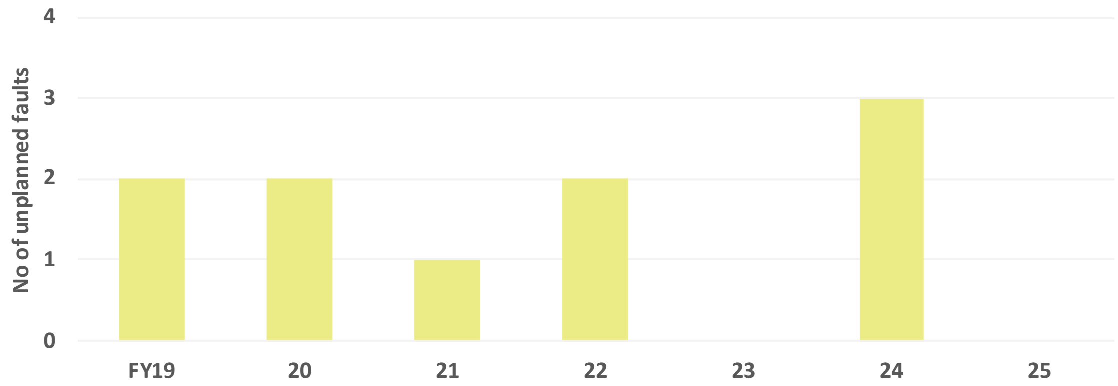
The performance of this fleet is measured by monitoring the number and type of failures, as shown in the figure below (excluding the RMUs suffering the type issue).

Figure 14.56 Performance - number of unplanned failures



The figure below shows the number of failures relating to the RMUs with the type issue. There have been several serious failures in recent years and an abnormally high failure rate compared to other types.

Figure 14.57 Performance - RMU type issue failures



These type-issue RMUs have an explosive failure mode, caused by internal phase to earth faults. Two significant explosive failures have occurred in the past, heightening the safety risk profile of these particular units. We have been working with the manufacturer and local distributor on the issue and will replace units at high-risk sites. In the meantime, we have put in place safety mitigation measures.

The table below summarises the key risks we have identified for our ground mounted switchgear.

Table 14.53 Identified risks and mitigations – ground mounted switchgear

Risk Area	Description	Mitigations
Health and safety Network interruption	Similar to zone substation indoor switchgear, we have oil-filled switchgear panels in distribution substations. These pose similar safety and operational risks, such as lack of capability to retrofit arc flash detection and protection. These switchgear panels are old, and often no longer supported by the manufacturer, so spares are not readily available	We are replacing switchgear panels that present unacceptable safety or performance risks, such as arc flash
Health and safety Network interruption	The majority of our RMUs are a model that has been shown to have a type issue. That model was installed on our network between 2014 and 2019, and the type issue has resulted in some of the units experiencing internal phase to earth faults, which poses both safety and network interruption risks. Since 2018, we have seen 10 failures, and several other owners of this type of RMU units have also experienced failures	We have been working with the manufacturer and local distributor on the issue and will replace units at high-risk sites. In the meantime, we have put in place safety mitigation measures
Health and safety	We have identified a safety risk where unfused MSUs may contribute to prolonged clearance times for transformer and low voltage faults	We are addressing this issue through our replacement programme
Network interruption	MSU contacts in coastal areas are particularly susceptible to corrosion	Targeted maintenance programme for coastal sites
Environment	SF_6 leakages from switchgear	We have not installed indoor switchgear panels with SF_6 as the interruption medium since 1992. As these reach end of life, we are replacing them with modern (non-SF_6) alternatives

14.7.3.5 Renewal strategy

Within our proactive MSU renewals programme we are prioritising replacement of unfused MSUs that may not always ensure adequate clearance times in the event of a substation low voltage busbar fault. A sizable proportion of the large MSU population is nearing end of life, so a substantial number of renewals will be needed during the AMP period.

We are replacing many RMUs due to a safety type issue. This work will be completed over the AMP period, with priority based on location and network criticality.

We also have a circuit breaker replacement programme over FY26 and FY27 for our distribution substation oil switchgear panels. These panels are typically installed at customer premises. The panels will be replaced with RMU-equivalents as this modern switchgear can provide the required functionality at lower cost.

Table 14.54 Renewal strategy – ground mounted switchgear

Tasks	Description
Renewal trigger	Condition Type issues – RMUs with safety issue, oil IDS panels Failure
Forecasting approach	We forecast proactive renewal volumes of ground mounted switchgear using: • Repex • Number of units in service – type issues
Cost estimation	Volumetric

14.7.3.6 Renewal forecasting approach

We have adopted a Repex approach to forecasting for ground mounted switchgear (except for the RMUs with the type issue). Renewal of the type-issue RMUs will be progressed in a specific programme to replace all of these units.

14.7.4 Enclosures

14.7.4.1 Asset overview

Distribution enclosures include distribution cabinets, distribution boxes, kiosks, and LV panels, as well as substation buildings located outside zone substations. Our fleet includes:

- **Distribution buildings**: standalone buildings (excluding those within zone substations). They vary in size and construction, typically containing at least one transformer, an 11 kV switch unit (MSU or RMU), and a LV distribution panel.
- **Kiosks**: a type of distribution substation. Made from steel, most are the older high style or the current half kiosk or low style. Full kiosks typically house a transformer, an 11 kV switch unit, and a LV distribution panel. Half kiosks typically house a switch unit and LV distribution panel, like a full kiosk, but any transformer is mounted on a concrete pad at the rear or side of the kiosk.
- **Distribution boxes and cabinets**: above-ground enclosures that house fuses, links, and connections to customer owned service cables, providing for configuration of the LV network through manually operated links. Together with LV cables, they are the final stage in our distribution system, providing electricity to customer premises and streetlights. Distribution boxes are generally installed on alternate boundaries on both sides of the street.

14.7.4.2 Asset population and age

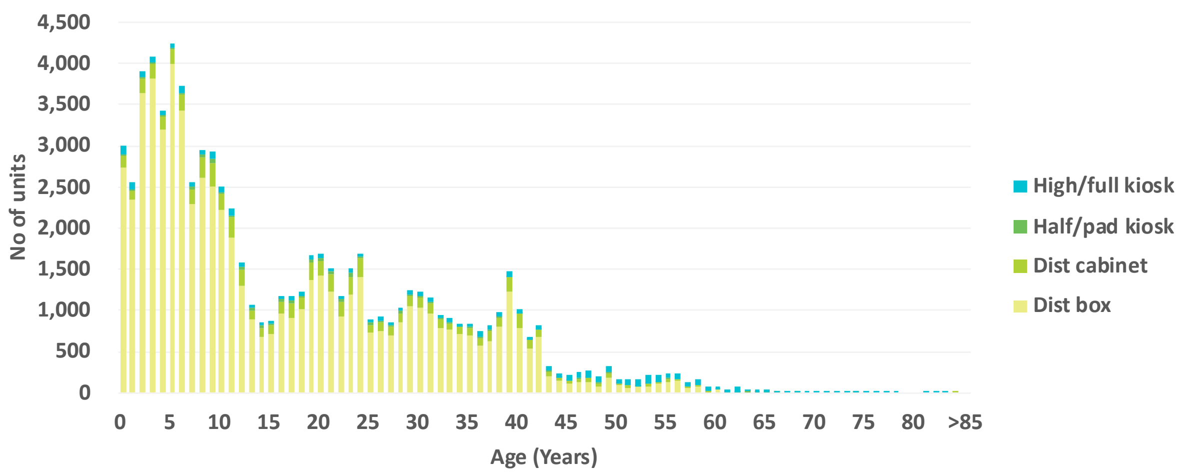
The table below summarises our population of enclosures by type.

Table 14.55 Population – enclosures

Asset type	Population (approx.)	Comments
Distribution boxes (majority are a polyethylene cover on a steel base frame)	64,900	Expected life 50-60 years (concrete expected to outlast plastic)
Distribution cabinets	7,070	Expected life 40-60 years
Half/pad kiosk	950	Newer kiosk type. Expected life 50-60 years
High/Full kiosk	3,740	Older kiosk type. Expected life 70-80 years
Total distribution cabinets, boxes, and kiosks	**76,660**	
Distribution substation buildings	250	

The figure below shows the age profile of our enclosures fleet. Distribution substation buildings are not included in the figure below. These buildings are maintained in perpetuity, or until they are no longer needed, using a combination of maintenance and refurbishment.

Figure 14.58 Age profiles – enclosures (excluding distribution substation buildings)

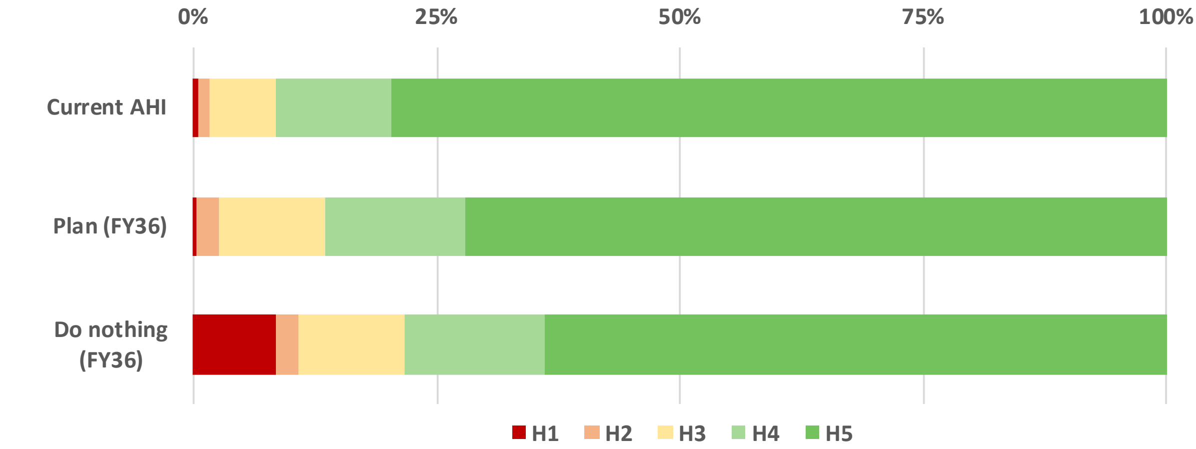


14.7.4.3 Asset health

We have adopted an age-based Repex approach to derive future asset health for our enclosures fleet, excluding distribution substation buildings. Our AHI for these assets reflects expected remaining life.

The figure below sets out an overview of the asset health scores for our enclosures fleet (excluding distribution substation buildings).

Figure 14.59 Asset health – enclosures (excluding distribution substation buildings)

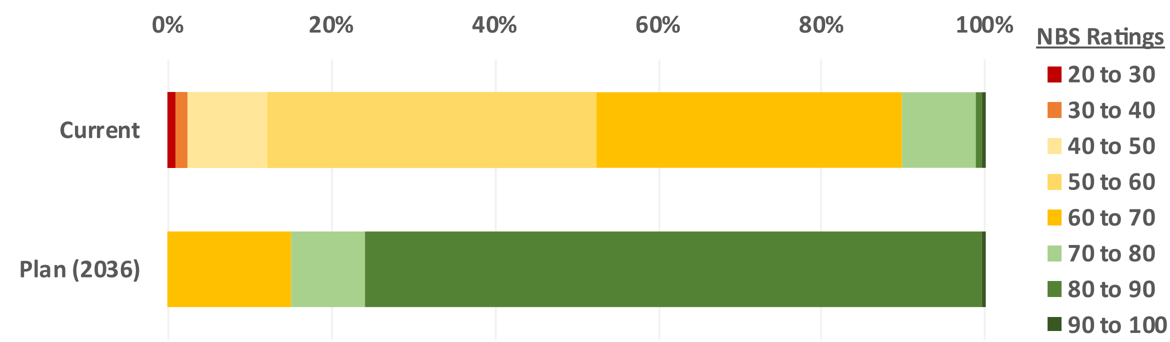


While our overall asset health appears to be in good condition, the H1 score is driven by a relatively large number of enclosures with skeleton type LV panels. These are an uninsulated type of switchgear with exposed live terminals and busbars. They present a risk to both public and operator safety. An interim solution was introduced which addressed the risk to public safety. We replaced enclosure doors, improved locking systems, and installed polycarbonate screens as a secondary insulation barrier. Safety signage was also installed. However, this did not fully address operational safety concerns. We will be replacing many of these with kiosks or distribution cabinets over the AMP period. As a result, overall fleet health is improved and safety risk reduced.

Distribution buildings seismic ratings

The figure below sets out the NBS ratings for our distribution substation buildings.

Figure 14.60 Distribution substation buildings NBS ratings



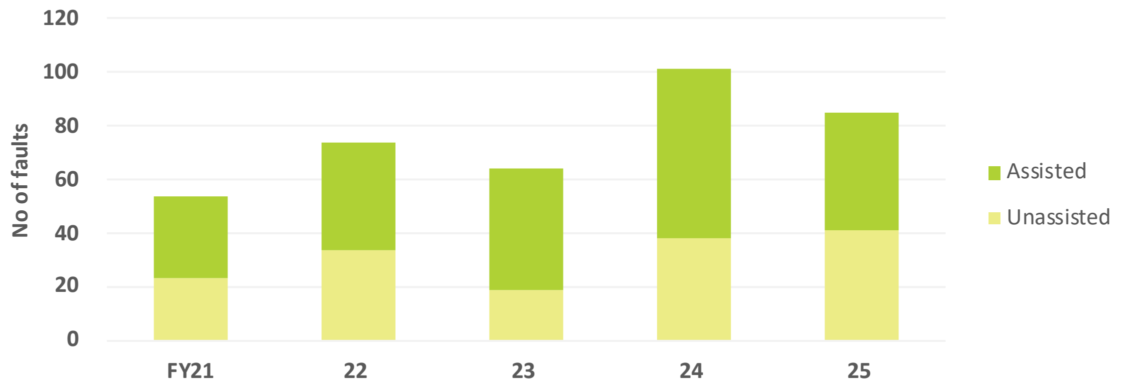
A significant number of our distribution substation buildings are currently below 67% of the NBS which is a trigger for seismic remediations consistent with other peer utilities' approaches. Our seismic remediation programme will reinforce buildings or convert them to kiosks over the AMP period. This will enhance our overall seismic resilience and bring the majority of buildings above 67% NBS by the end of the AMP period.

14.7.4.4 Asset performance and risk

Failure of enclosures can pose a significant safety risk as it can expose the public and personnel to electrocution. Failure can also cause damage to the enclosed assets, e.g. distribution switchgear, distribution transformers, and LV panels.

The performance of this fleet is measured by monitoring the number of faults causing outages, as shown in the figure on the following page.

Figure 14.61 Performance - distribution boxes and cabinet faults causing outages



The number of faults causing outages is trending upwards. These faults are primarily 'assisted', i.e. motor vehicle collision with the box or cabinet, or intentional damage.

The table below summarises the key risks we have identified for our enclosures.

Table 14.56 Identified risks and mitigations – enclosures

Risk Area	Description	Mitigations
Network interruption	Kiosks in coastal areas are particularly susceptible to corrosion	Targeted maintenance programme for coastal sites
Health and safety	We have identified a safety issue with skeleton LV panels inside our kiosks and distribution cabinets These panels are an uninsulated type of switchgear with exposed live terminals and busbars. These present a risk to both public and operator safety	Interim solution partially addressed the risk to public safety by replacing enclosure doors, improving locking systems, and installing polycarbonate screens as a secondary insulation barrier. Safety signage was also installed We are prioritising replacement of enclosures that contain skeleton panels
Network interruption	Some enclosures in low lying areas will be inundated in the event of flooding	We have a new distribution box design which will replace existing boxes if inundated
Network interruption	Our distribution substations are not all up to NBS standard for IL3 buildings, which are important sites for restoring electricity following a seismic event	We refurbish to improve the seismic strength of our distribution substation buildings to at least 80% of the NBS for IL3 buildings Completion of initial seismic assessments
Network interruption Health and safety Environment	We are subject to a fire separation standard that specifies the distance that oil-filled transformers need to be from combustible surfaces. Our kiosks contain distribution transformers. There is a risk as some of those kiosks are in residential areas where there may be wooden fences or trees etc nearby. If a transformer caught on fire, it is likely to leak oil. If the oil is not contained, it will spill outside of the kiosk and could be ignited or spread	Renewal works to remediate this risk

14.7.4.5 Renewal strategy

We aim to maintain our distribution substation buildings in serviceable condition until such time as the building is no longer needed or no longer fit for purpose.

Our plan for the AMP period is to upgrade most of the lower NBS rated buildings, while replacing the remainder with kiosks, where this solution is suitable. We estimate that this split will be about 75% renewal and 25% conversion to kiosk. We will prioritise upgrades to the buildings based on their respective ratings.

We replace kiosks and smaller enclosures based on asset health. When a kiosk is to be replaced, we also consider the type of LV panel on site and the age and condition of the switchgear and distribution transformers, as it is more efficient to carry out a complete replacement or combine replacement of several elements. The forecast provides for accelerated replacement of enclosures containing skeleton LV panels.

Table 14.57 Renewal strategy – enclosures

Tasks	Description
Renewal trigger	Condition and/or safety risks Seismic rating (buildings) Overhead to underground conversions (distribution boxes) Third party damage
Forecasting approach	We forecast proactive renewal volumes of enclosures using: • Repex • NBS ratings • Number of enclosures affected by overhead to underground conversions
Cost estimation	Volumetric

14.7.4.6 Renewal forecasting approach

We have adopted the following renewal forecasting approaches for our enclosures:

- a Repex methodology for kiosks and distribution boxes and cabinets.
- an approach for distribution substation buildings that triggers remediation when they reach a NBS rating of 70%
- a percentage of population approach to forecast the quantity of renewals each year for LV panels that are not the skeleton type.

We use a volumetric approach to cost estimation. Unit rates are based on historical average cost covering a wide range of brownfield conditions for each of distribution boxes, cabinets and kiosks. If the enclosure has an LV panel that also needs replacing, this has an additional unit cost per LV panel. We also have unit rates for building upgrades and kiosk conversions (which include a high kiosk, RMU, distribution transformer, foundations and land).

14.7.5 Ancillary equipment

14.7.5.1 Asset overview

Our ancillary equipment fleet is made up of mainly distribution switchgear-related assets that are not captured in the fleets above. It includes (but is not limited to) surge arrestors, earthing, and fire and security systems. Surge arresters are installed to protect network equipment against voltage surges and are typically installed on underground cables, reclosers, and some pole mounted transformers. All accessible metal equipment on the distribution network must be earthed. Earth points are tested periodically for resistance to ensure equipment remains safe in the case of faults or induced voltage.

14.7.5.2 Asset population and age

We do not currently have complete population or age data for this fleet, although data on surge arresters will be systematically collected in our new asset management system.

14.7.5.3 Asset performance and risk

The table below summarises the key risks we have identified for our ancillary equipment.

Table 14.58 Identified risks and mitigations – ancillary equipment

Risk Area	Description	Mitigations
Network interruption Health and safety	Inadequate earthing of metal equipment, or failure of the earthing to perform, can lead to an increase in potential 'step or touch' hazards	Current injection and step and touch potential testing Corrective maintenance to repair earthing leads and connections

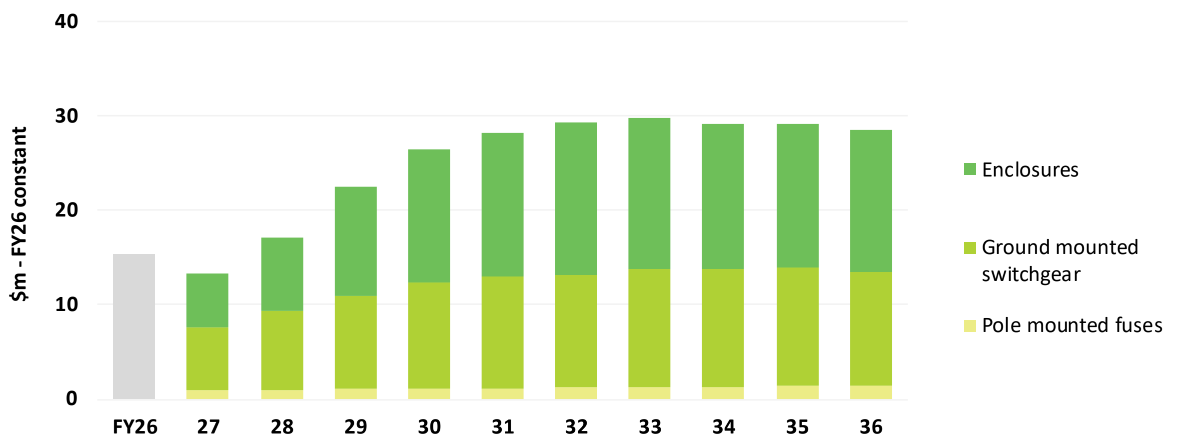
14.7.5.4 Renewal strategy

We have not forecast planned renewals for this fleet.

14.7.6 Distribution switchgear forecast capex

The following figure shows our forecast capex for distribution switchgear.

Figure 14.62 Planned distribution switchgear renewals capex



Our distribution switchgear forecast predominantly comprises renewals of enclosures and ground mounted switchgear. Pole mounted fuses expenditure is relatively low, focusing on replacing poor condition fuses and replacing fuses in extreme or higher wildfire risk areas with sparkless fuses. For enclosures, the programme will gradually lift over the AMP period, prioritising renewal of enclosures with skeleton panels (safety risk).

We will also begin our seismic remediation programme by reinforcing or converting buildings to kiosks. Our ground mounted switchgear programmes are similarly safety risk focused. Throughout the AMP period, we will replace safety type issue RMUs, progressively phase out oil-filled indoor switchgear and replace them with RMUs, and prioritise unfused MSUs.

14.8 Distribution transformers

Distribution transformers convert electricity from 11 kV to 400 V to supply our customer connections. We have more than 12,000 distribution transformers installed on our network.

This section outlines the asset fleets that make up our distribution transformers asset class:

- ground mounted transformers
- pole mounted transformers
- voltage regulators and capacitors
- generators.

14.8.1 Ground mounted transformers

14.8.1.1 Asset overview

Ground mounted transformers can support higher capacity loads than pole mounted transformers, making them ideal for urban and industrial areas where power is distributed via underground cables. Our ground mounted transformers range in rating from 5 to 1,500 kVA, with most of them larger than 100 kVA. They are installed either outdoors or inside a building or kiosk. Kiosks can only accommodate transformers up to 500 kVA. Being at ground level, these transformers are more accessible for maintenance than pole mounted transformers.

14.8.1.2 Asset population and age

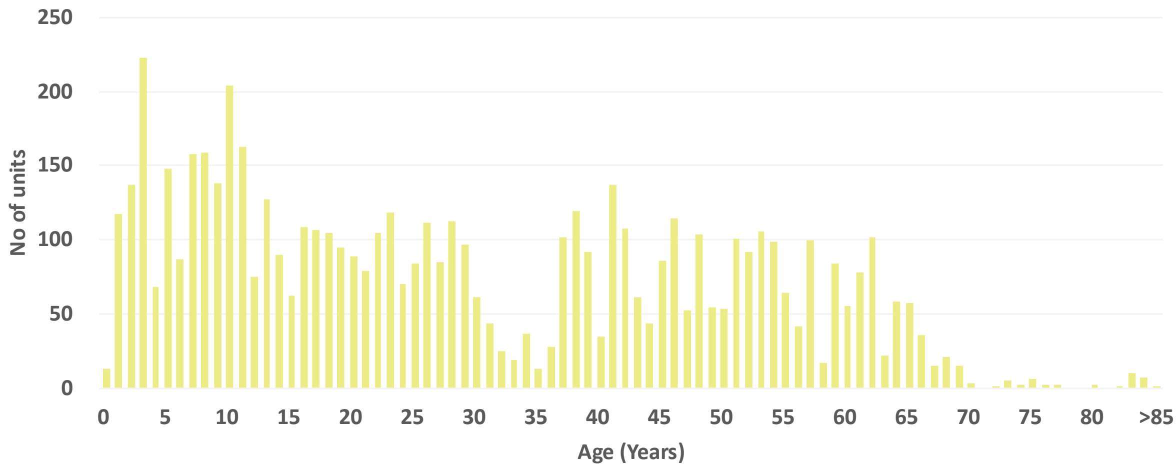
The table below summarises our population of ground mounted transformers by rating. The remaining large pole mounted transformers (200-300 kVA) that will be replaced with ground mounted units at end of life are included in this table.

Table 14.59 Population - ground mounted transformers

Rating	Population (approx.)
5 - 100 kVA	570
100 - 500 kVA	4,650
>500 kVA	720
Total	**5,940**

The figure on the following page shows the age profile of our ground mounted transformers fleet. The expected life of these assets is 75 years. Some of our ground mounted transformers have already reached, or will reach, their expected life during the next decade.

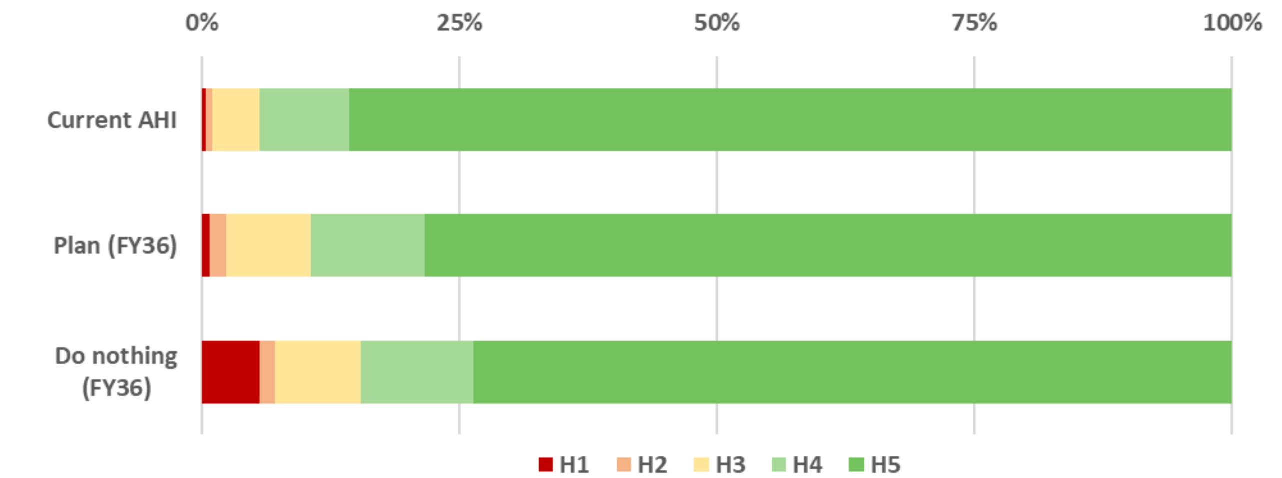
Figure 14.63 Age profile - ground mounted transformers



14.8.1.3 Asset health

We have adopted a Repex approach to derive future asset health which determines how many units need to be replaced in each future year based on the existing age profile of the assets. The figure below sets out an overview of the asset health scores for our ground mounted transformers fleet.

Figure 14.64 Asset health – ground mounted transformers



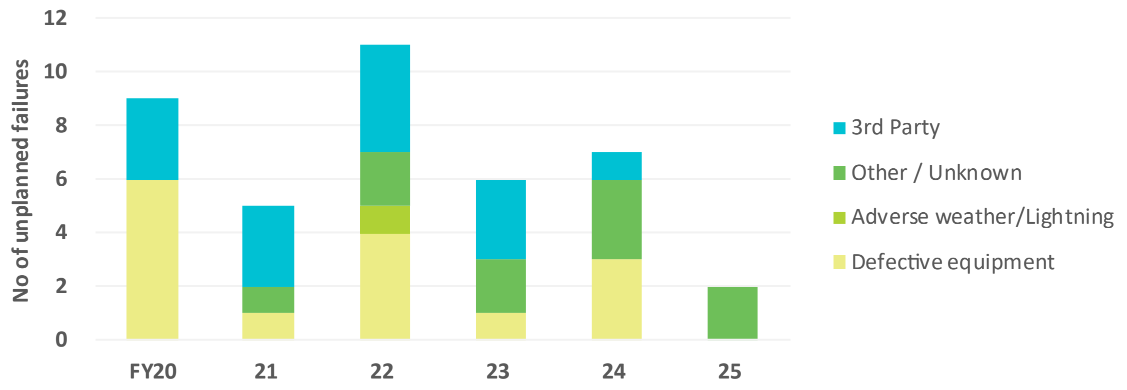
The ground mounted transformer fleet is generally in good condition, with only a very small amount considered H1. We expect to replace more units based on condition in the coming decade as further units reach replacement triggers.

Even with our planned investments, asset health is expected to decline slightly over the AMP period as an increasing number of units exceed their expected service life. Aggregate health would decline significantly if renewals were deferred, as depicted in the 'do-nothing' scenario. This would present increasing asset failure reliability risks.

14.8.1.4 Asset performance and risk

The performance of this fleet is measured by monitoring the number and type of unplanned faults, as shown in the figure below. Most faults relate to equipment defects and third-party incidents, such as vehicle impact.

Figure 14.65 Performance – ground mounted transformers



We consider our ground mounted transformers to be in good condition but have identified a risk in relation to fire separation standards. While we have not experienced any transformer fires causing damage to customer property, we do recognise that some of our larger units located inside, or next to kiosks, may be inadequately separated from nearby combustible structures, such as wooden fences. Similarly, we have units located in approx. 200 customer premises which may not meet the fire separation standards.

Where this risk exists, it will mostly be managed by renewal with ester oil compatible transformers, in preference to mineral oil, which are considerably less flammable so have lower separation requirements. Ester oil is also more environmentally friendly (biodegradable and non-toxic), and moisture tolerant, but requires dedicated handling equipment and has a higher upfront cost.

The table below summarises the key risks we have identified for our ground mounted transformers.

Table 14.60 Identified risks and mitigations – ground mounted transformers

Risk Area	Description	Mitigations
Network interruption	Insulation failure caused by lightning	Surge arresters are fitted at cable terminations (to the lines) in rural areas to protect ground mounted transformers
Network interruption	Moisture ingress due to deterioration of enclosure seals Corrosion	Inspection, maintenance, and replacement programmes
Environmental	Oil leakage into the environment	Inspection, maintenance, and replacement programmes
Environmental	Distribution transformer noise complaints	Inspection and replacement programmes
Health and safety	Third party damage or access or theft	Installation of visible warning signs. Locks and inspections Public safety campaign in relation to third parties tampering our network assets
Network interruption	Distribution transformer failure due to age or condition related internal failure	Spares Condition assessment or testing of larger transformers Replacement programmes

Table 14.60 Identified risks and mitigations – ground mounted transformers		
Risk Area	**Description**	**Mitigations**
Health and safety	Poor or missing earthing connections or inadequate earthing	Testing and inspections of earthing leads, connections and earth grid Corrective maintenance
Network interruption Health and safety	We are subject to a fire separation standard that specifies the distance that oil-filled transformers need to be from combustible surfaces. Our kiosks contain distribution transformers. There is a risk as some of those kiosks are in residential areas where there may be wooden fences or trees etc nearby. If a transformer caught on fire, it is likely to leak oil. If the oil is not contained, it will spill outside of the kiosk and could be ignited or spread.	Assessing scope of the issue. Fire engineers will assess and recommend mitigation measures for customer premises We will replace those transformers in or next to kiosks with ester oil-filled units at end of life

14.8.1.5 Renewal strategy

Our preventive maintenance inspections and condition assessments identify distribution transformer assets for replacement, based on age, condition, and performance. This accounts for most of our renewals. In addition, we replace smaller, low consequence units when they fail. We are also pre-emptively replacing a small number of units each year to address fire risk.

Transformers for which the rating is becoming insufficient for the load on it are replaced under the growth portfolio. The transformer that is removed may be refurbished and installed at another location.

Table 14.61 Renewal strategy – ground mounted transformers	
Tasks	**Description**
Renewal trigger	Condition Reactive
Forecasting approach	We forecast proactive renewal volumes using Repex modelling
Cost estimation	Volumetric

14.8.1.6 Renewal forecasting approach

We have adopted the Repex approach for our ground mounted transformers, using a life expectancy of 75 years.

14.8.2 Pole mounted transformers

14.8.2.1 Asset overview

We typically use pole mounted transformers in our overhead network in rural and suburban areas; they range in size from 15 kVA to 300 kVA. Most pole mounted transformers are smaller than 100 kVA. Due to seismic structural limitations, we now limit the size of pole mounted transformers to no more than 200 kVA and are progressively replacing larger transformers with ground mounted units.

While most of these transformers are single or three-phase types, but we also have a small number of single wire earth return (SWER) isolation transformers used in remote rural areas.

Pole mounted transformers avoid the need for concrete pads or enclosures but are more vulnerable to extreme weather and environmental damage. They are more difficult to access for maintenance than ground mounted units.

14.8.2.2 Asset population and age

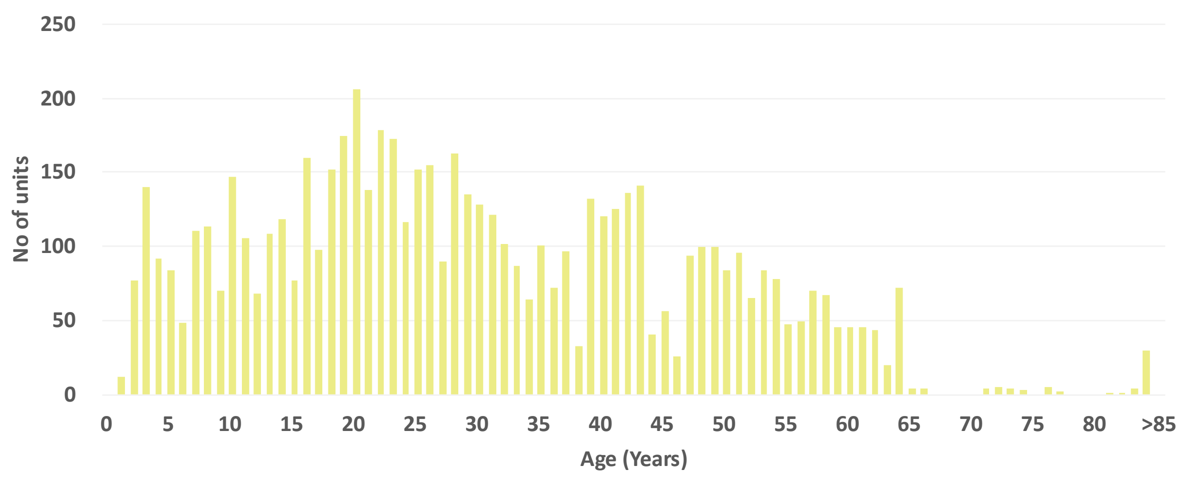
The table below summarises our population of pole mounted transformers by rating. Transformers that are 200 kVA or larger are included in the ground mounted transformer fleet, pending conversion.

Table 14.62 Population - pole mounted transformers

Rating	Population (approx..)
5 - 15 kVA	640
15 - 30 kVA	3,300
30 - 200 kVA	2,200
>200 kVA	180
Total	**6,320**

The figure below shows the age profile of our pole mounted transformers fleet. These assets have a shorter expected life than ground mounted units, as they are more exposed to the weather and environmental contaminants. Some have already exceeded their expected life of 65 years.

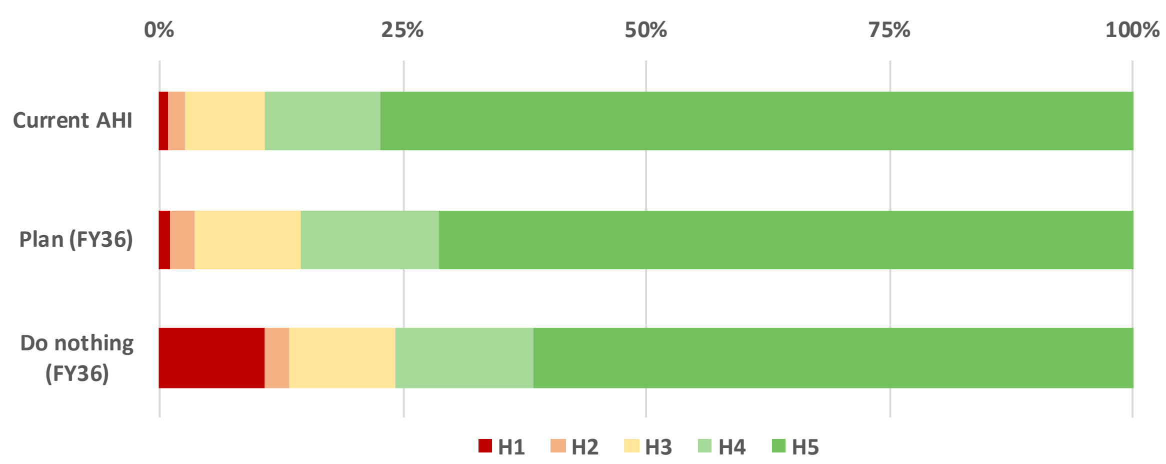
Figure 14.66 Age profiles - pole mounted transformers



14.8.2.3 Asset health

We have adopted an age-based Repex approach to derive future asset health which determines how many units need to be replaced in each future year based on the existing age profile of the assets. The figure below sets out an overview of the asset health scores for our pole mounted transformers fleet.

Figure 14.67 Asset health – pole mounted transformers

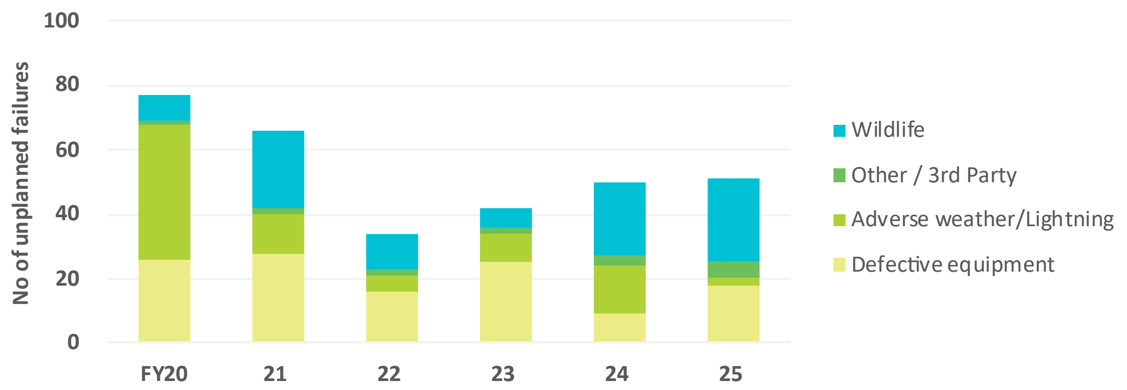


The pole mounted transformer fleet is generally in good condition, with only a relatively small amount considered to be H1. Our investment plan over the AMP period seeks to maintain overall fleet health.

14.8.2.4 Asset performance and risk

The performance of this fleet is measured by monitoring the number and type of unplanned faults, as shown in the figure below.

Figure 14.68 Performance – pole mounted transformers



The failure rate is relatively low but, as would be expected, higher than that of our ground mounted transformers. This is due to the constant exposure of pole mounted units to the environment, more frequent exposure to lightning-induced voltage surges and wildlife, as well as the much longer maintenance interval. It is not economic to routinely test and maintain them in service.

The table below summarises the key risks we have identified for our pole mounted transformers.

Table 14.63 Identified risks and mitigations – pole mounted transformers

Risk Area	Description	Mitigations
Network interruption	Moisture ingress due to deterioration of enclosure seals Corrosion	Inspection, maintenance, and replacement programmes
Network interruption	Pole mounted transformers are located outside so are exposed to: • lightning strikes • faults caused by wildlife • extreme weather	Installation of more surge arrestors to minimise failures due to lightning strikes There are few workable options to address the wildlife risk, as our poles already have possum guards installed, and bird guards are not feasible
Network interruption Health and Safety	Third party damage (car vs pole)	High visibility reflectors Asset relocations
Network interruption	Pole mounted transformer failure due to age or condition related internal failure	Inspection, maintenance, and replacement programmes
Environmental	Oil leakage into the environment	Inspection, maintenance, and replacement programmes
Health and safety	Copper theft	Public information safety campaign Installation of visible warning signs
Health and safety Network interruption	There are safety risks related to earthquakes for our large overhead pole mounted transformers	Convert large overhead pole mounted transformers to ground mounted units

14.8.2.5 Renewal strategy

We expect to maintain our current levels of reactive replacements and supplement this with a new programme of proactive replacements. This programme will ramp up as our fleet ages over the AMP period.

Our inspections of pole mounted transformers are done as part of a visual inspection of pole top hardware that occurs every five years. We replace pole mounted transformers when found to be in poor condition during these inspections. We will be refining our inspections approach and improving data quality to support prioritisation over the AMP period.

We also have a programme of work replacing larger pole mounted units with ground mounted units when they come due for renewal. These units are included in the ground mounted transformers fleet.

Table 14.64 Renewal strategy – pole mounted transformers

Tasks	Description
Renewal trigger	Condition Failure
Forecasting approach	We forecast proactive renewal volumes of pole mounted transformers using Repex
Cost estimation	Volumetric

14.8.2.6 Renewal forecasting approach

We have adopted the Repex renewal forecasting approach for our pole mounted transformers, using an expected life of 65 years.

14.8.3 Voltage regulators and capacitors

14.8.3.1 Asset overview

A voltage regulator helps keep supply voltage at a constant level, regardless of load fluctuations. 11 kV line voltage regulators are installed at various locations to increase capacity where it is limited by voltage constraints. We use a wide range of ratings to accommodate different load densities within our network. All regulators are oil-filled, with automatic voltage control through an on-load tap changer. The fleet includes three large voltage regulators, originally owned by Transpower, located at Heathcote.

We have several other asset types that provide reactive voltage support, including capacitor banks and static synchronous compensators (STATCOMs). STATCOMs can offer a continuously variable voltage support response. We have many ferro-resonance capacitors, which are used to mitigate or control ferro-resonance, to protect our transformers from over voltages or current surges.

14.8.3.2 Asset population and age

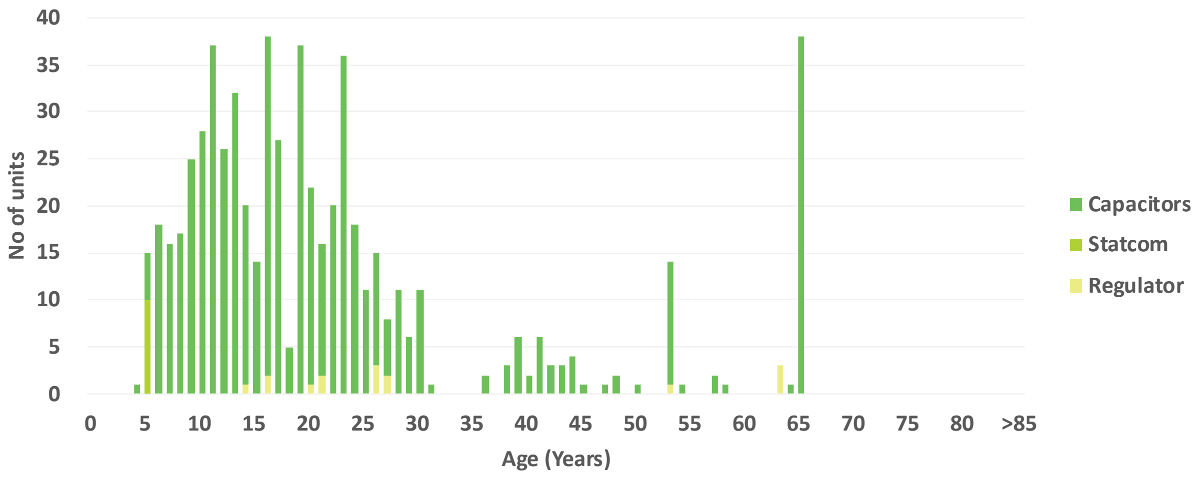
The table below summarises our population of voltage regulators and capacitors by type.

Table 14.65 Population - voltage regulators and capacitors

Asset type	Population (approx.)	Expected life
Voltage regulator	15	20 years
STATCOM/mobile STATCOM	10	20 years
Capacitors	600	10 years
Total	**625**	

The figure below shows the age profile of our voltage regulators and STATCOMs. Distribution voltage regulators have an average age of 24 years, against a 20-year expected life, though this average is skewed by the older units. The three large voltage regulators at Heathcote zone substation, are 63 years old, with tap changers, and aged control gear.

Figure 14.69 Age profiles - voltage regulators and STATCOMs

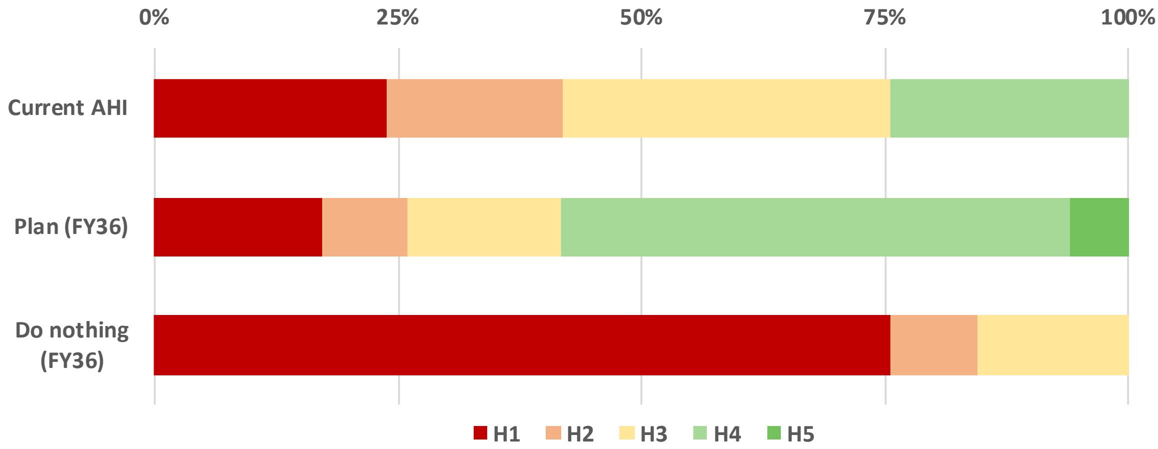


14.8.3.3 Asset health

We have adopted an age-based Repex approach to derive future asset health which determines how many units need to be replaced in each future year based on the existing age profile of the assets, and the statistical distribution that describes the historical age at end of life for that asset type.

The figure below sets out an overview of the asset health scores for our voltage regulators and STATCOMs. We have omitted ferro-resonance capacitors and voltage support capacitors from the asset health assessment at this stage as we are in the process of improving our age and condition data.

Figure 14.70 Asset health – voltage regulators and STATCOMs



Our renewal plan seeks to improve overall fleet health. Deferring renewals will further increase asset failure risk, which could cause voltage instability leading to network interruptions.

14.8.3.4 Asset performance and risk

When voltage regulators and capacitors fail, they do not necessarily cause an outage, but can result in loss of reactive support, which may cause areas of the network to be temporarily outside of voltage limits. We have experienced two unplanned faults related to voltage regulators.

The table below summarises the key risks we have identified for our voltage regulators and capacitors.

Table 14.66 Identified risks and mitigations – voltage regulators and capacitors

Risk Area	Description	Mitigations
Health and safety	Voltage regulator failures leading to overvoltage or undervoltage which can damage customer equipment and create fire risks	Inspection, maintenance and renewal programmes
Network interruption	Loss of regulation can cause voltage fluctuations that can affect protection relay coordination, ultimately leading to protection to trip the affected feeder	Inspection, maintenance and renewal programmes
Compliance and regulatory	Voltage regulator failures leading to persistent non-compliance with power quality standards	Inspection, maintenance and renewal programmes

14.8.3.5 Renewal strategy

We are taking a proactive approach to renewal of our regulators and capacitors. Most of our current units are nearing, or have already exceeded, end of life and will be replaced as warranted by condition and performance.

Table 14.67 Renewal strategy – voltage regulators and capacitors

Tasks	Description
Renewal trigger	Condition Failure
Forecasting approach	We forecast proactive renewal volumes using a Repex methodology
Cost estimation	Volumetric

14.8.3.6 Renewal forecasting approach

We have adopted the Repex renewal forecasting approach for our voltage regulators and capacitors. We have used 10 to 15 years as the life expectancy of capacitors.

14.8.4 Generators

14.8.4.1 Asset overview

Our generators supply customers for short periods during fault repairs and planned interruptions and provide supply to our building and other essential infrastructure for continued capability in the event of an emergency.

This fleet is made up of 3 types:

1. **400 V truck-mounted mobile generators**: used to restore or maintain supply at a LV distribution level for short periods during a fault or planned work.
2. **400 V building generators**: used to restore or maintain supply to our building and other essential infrastructure to ensure continuity of capability in the event of emergency. All have synchronisation equipment and can supply the entire building load.
3. **400 V emergency standby generators**: these can be strategically placed throughout our urban network for emergency backup.

This fleet also includes diesel tanks and a mobile trailer tank to maintain a fuel supply for the generators.

14.8.4.2 Asset population and age

The table below summarises our population of generators by type.

Table 14.68 Population - generators

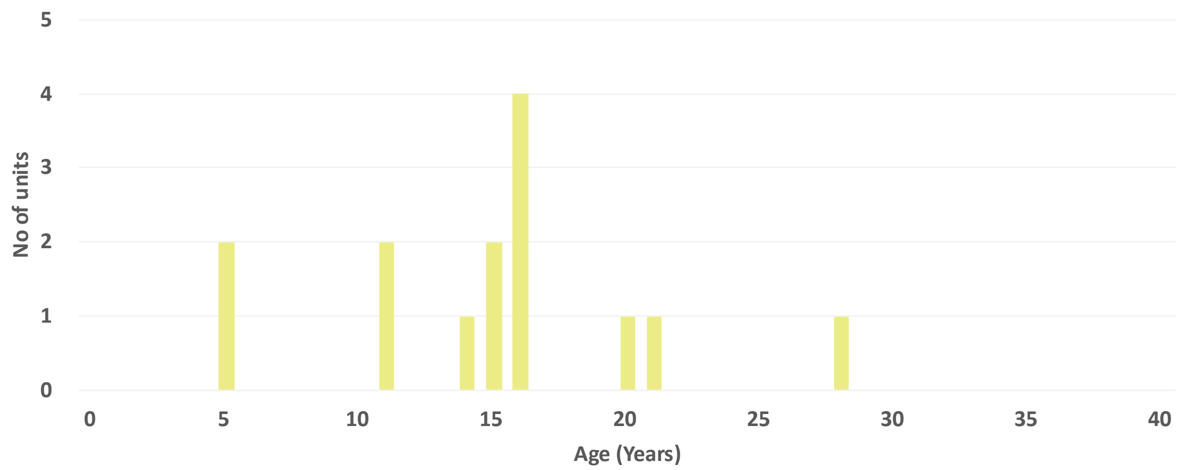
Asset type	Population
Truck/trailer mounted mobile generators - ranging from 110 to 550 kVA.	5
Building generators - ranging from 110 to 550 kVA.	3
Emergency standby generators - ranging from 8 to 550 kVA.	6
Total	14

We also have six diesel tanks and a mobile trailer tank. The purpose of the tanks is to:

- provide an emergency reserve fuel supply for the operator vehicle fleet and building generators should the Christchurch supply lines become disrupted
- fuel the generator at our Wairakei Road head office building in an emergency for an extended period
- fuel mobile generators (trailer tank).

The figure below shows the age profile of our generators fleet, against their expected life of 30 years. Our larger units are nearing mid-life, while our mid-size and small units have a range of ages.

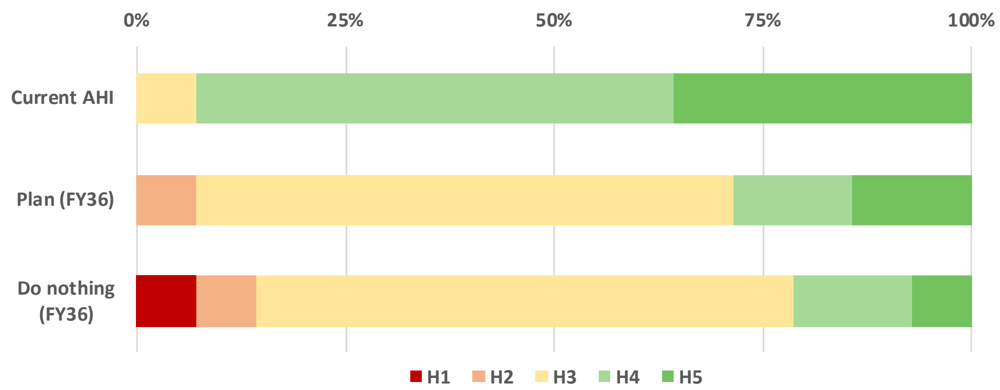
Figure 14.71 Age profiles - generators



14.8.4.3 Asset health

The figure below sets out an overview of the asset health scores for our generators fleet.

Figure 14.72 Asset health – generators



All our generators are in relatively good condition and have had no major mechanical issues. One of our truck mounted mobile generators is approaching 10,000-hours of operation, which is the manufacturer's recommended maximum operating runtime. However, this unit has now been serviced, and its condition will be reassessed during the next inspection cycle or once it has exceeded another 5,000 hours.

14.8.4.4 Asset performance and risk

All generators are operated within their nameplate ratings. The table below summarises the key risks we have identified for our generators.

Table 14.69 Identified risks and mitigations – generators

Risk Area	Description	Mitigations
Network interruption	Generator fails to startup when required to feed supply during planned or unplanned work	Unit maintenance and renewal
Environmental Health and safety	Fuel leaks creating fire or contamination	Inspection and corrective maintenance Appropriate operating procedures
Health and safety	Backfeed into the network if isolation is not properly managed	Robust and appropriate operating procedures

14.8.4.5 Renewal strategy

We regularly maintain our generators and when one approaches end of life, a condition-based assessment will be conducted to see when the replacement is optimal.

Table 14.70 Renewal strategy – generators

Tasks	Description
Renewal trigger	Condition
Forecasting approach	We forecast proactive renewal volumes of generators using a simple model that compares age to expected life
Cost estimation	Volumetric

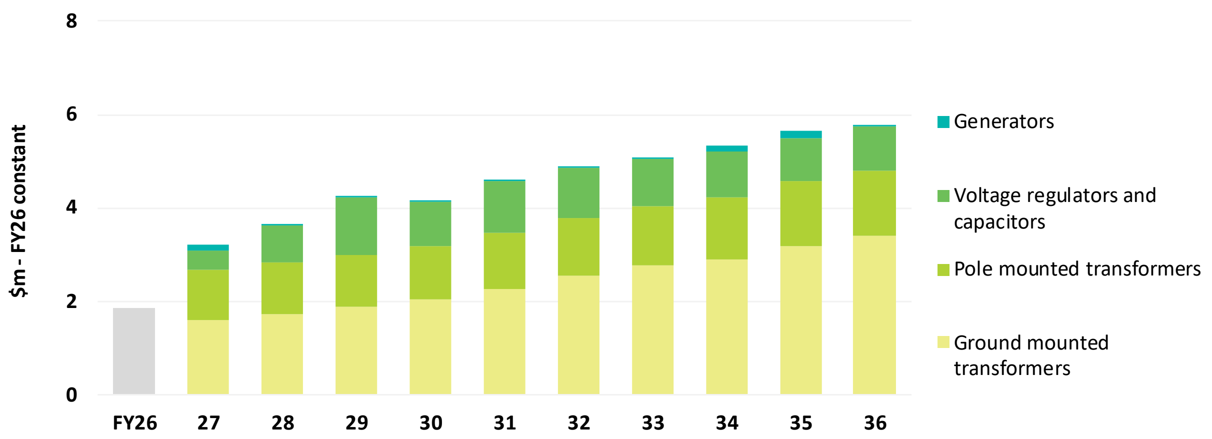
14.8.4.6 Renewal forecasting approach

We have adopted a simple renewal forecasting approach that uses a model that compares age to expected life.

14.8.5 Distribution transformers forecast capex

The following figure shows our forecast capex for distribution transformers.

Figure 14.73 Planned distribution transformers renewals capex



Our distribution transformers forecast increases in line with our enclosures and ground mounted switchgear programmes as these works are typically delivered together. Planned investment also includes the conversion of large pole mounted transformers to ground mounted equivalents due to the seismic and safety risks. Historically, pole mounted transformer renewals were limited to reactive replacements and while we expect some of these to continue, we are planning more proactive replacements throughout the AMP period. Our voltage regulators and capacitors replacement programme is primarily driven by ferro-resonance capacitor replacements. While we are planning to replace only a small number of voltage regulators, these are generally more expensive and represent a larger proportion of the forecast. Our generators forecast is mainly comprised of controller replacements, with a small number of generator replacements over the AMP period.

14.9 Secondary systems

Our secondary systems assets support our reliability objectives. Their main function in most cases is to support the safe and reliable operation of the electricity system. This section outlines the asset fleets that make up our secondary systems asset class:

- protection
- signalling/communications cables
- SCADA - (RTUs)
- communications
- batteries and DC supplies
- metering.

14.9.1 Protection

The primary function of our protection system assets is to detect abnormal operating or fault conditions so that they can be interrupted by switchgear assets. This function protects primary equipment and ensures the safety of employees, service delivery partners, and the public in the event of electrical faults. Reliable performance is critical to the operation of our network; failure of protection to clear a fault poses a significant safety risk.

Protection schemes are comparatively low cost compared to primary plant components, but they have a significant impact on the performance and safety of our network, making them highly critical.

14.9.1.1 Asset overview

Our protection fleet is made up of two types:

1. **Electromechanical devices**: these devices are legacy components typically installed with older switchgear. We continue to install them in some applications, such as bus zone protection, that require limited functionality. The higher reliability, long life, and relatively low maintenance characteristics of these devices are better suited to this high criticality application.
2. **Numerical/microprocessor-based relays**: have become the most prevalent type, offering multiple functions integrated into a single device, such as protection, control, and metering.

We have protection for bus zone, transformers, feeder, ripple plant, subtransmission, and distribution. The protection fleet also includes protection cabinets, settings, associated control wiring, test blocks, switches, and indication.

14.9.1.2 Asset population and age

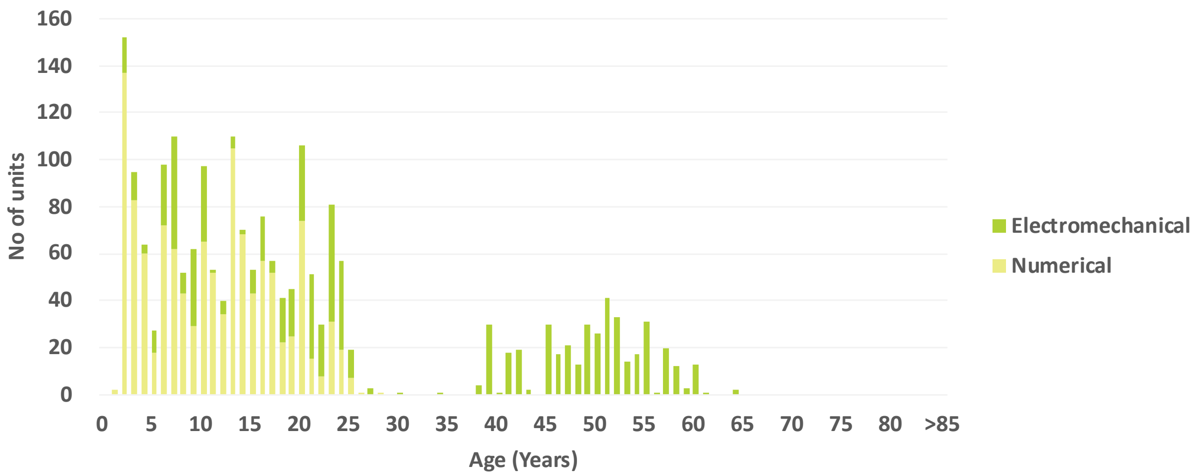
The table below summarises our population of protection assets by type and number of schemes. Each scheme comprises one or more relays. A modern equivalent scheme may contain fewer relays than the scheme it is replacing.

Table 14.71 Population – protection scheme

Asset type	Scheme numbers (approx.)
Electromechanical	870
Numerical	1,185
Total	**2,055**

The figure below shows the age profile of our protection fleet.

Figure 14.74 Age profiles – protection schemes



Historically, substation protection, control, and metering functions were performed by electromechanical relays. The figure above shows that those relays have now been largely superseded by numerical types.

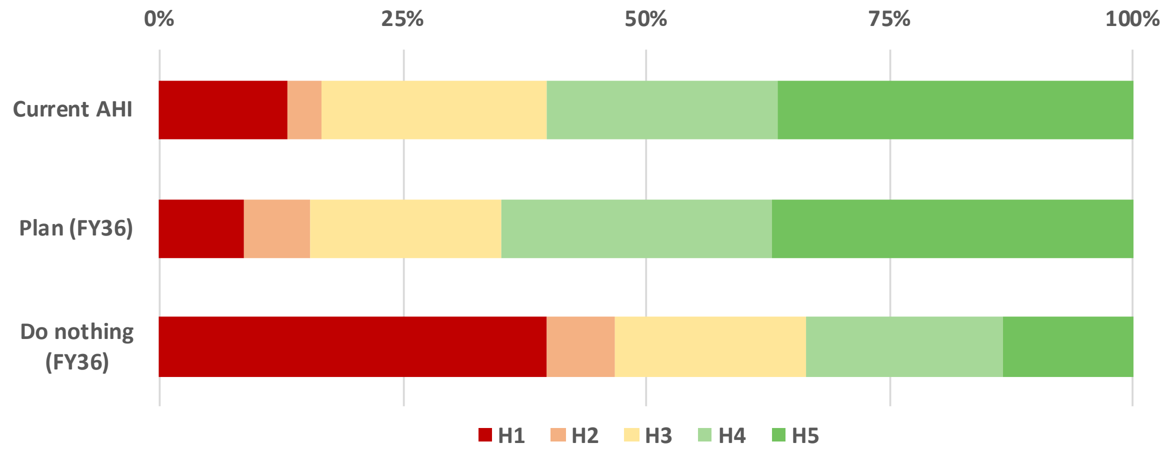
While electromechanical schemes have a substantially longer expected life (50 years, compared to 25 years for numerical), many have now exceeded that age. Some models are also becoming difficult to maintain as manufacturers withdraw support of obsolete types.

The oldest numerical schemes have exceeded 25 years of age. The shorter life of numerical type is due to factors such as failure modes of some electrical components, obsolescence, loss of vendor support for components or firmware, and cyber-security risk.

14.9.1.3 Asset health

We have adopted an age-based approach to derive future asset health. The figure below sets out an overview of the asset health scores for our protection fleet.

Figure 14.75 Asset health – protection



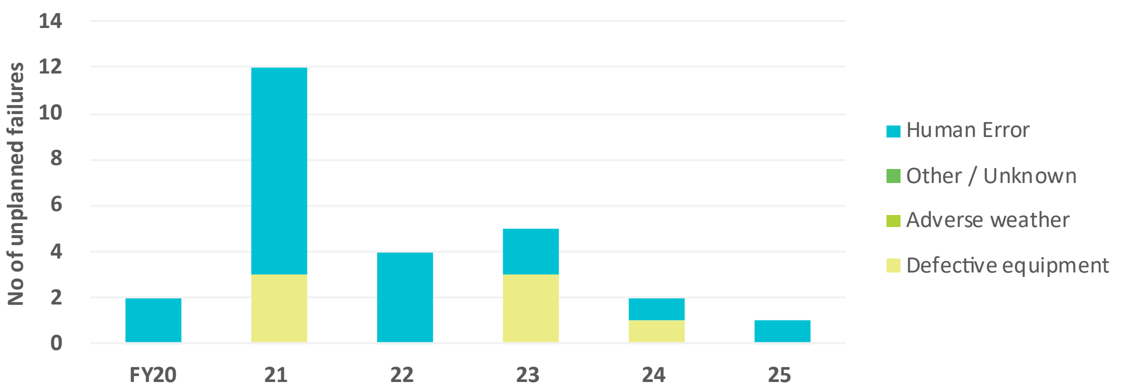
Our current levels of H1 are predominantly driven by obsolete electromechanical relays that have also exceeded their expected life. Our renewal programme plans to prioritise replacements of electromechanical relays and transition to other numerical types that will reach their end of life during the period. This will improve overall health of the fleet, reducing overall obsolescence risk and protection failure risk. Deferral of these renewals would result in a large proportion of the fleet being overdue for replacement, as depicted in the 'do-nothing' scenario. This would increase asset failure risk leading to heightened safety and reliability risks.

14.9.1.4 Asset performance and risk

Failure of protection to clear a fault poses a significant safety risk as it can expose the public and personnel to electrocution as the faulted equipment may still be live. Failure can also cause costly damage to the primary equipment they are associated with, so we aim to proactively replace protection before failure.

We monitor the faults on our protection assets by identifying the causes, as shown in the figure below. To date, there have been no protection mal-operations leading to material health and safety incidents, this is mainly because most protection has back-up clearance.

Figure 14.76 Performance – number of unplanned faults



The figure above shows that in addition to failures from defective equipment, several faults were caused by human error. Human error incidents were primarily caused by the increasingly complexity of protection systems. To mitigate these incidents, we have an ongoing training programme for our technicians. This includes training on standard designs for protection schemes, maintenance best practice, and on-the-job training and support for service delivery partners. Human error incidents have been trending downwards since FY21, and we are focused on maintaining these improvements.

The table below summarises the key risks we have identified for our protection fleet.

Table 14.72 Identified risks and mitigations – protection

Risk Area	Description	Mitigations
Network interruption Health and safety	Electrical failure caused by ageing relays prone to 'nuisance tripping'	Repair if economic and product is still supported by manufacturer or spares are available Replacement
Network interruption Health and safety	Electrical failure caused by loose wiring and termination	Inspection and testing
Network interruption Health and safety	Functional failure caused by ageing and obsolescence	Repair if economic and product is still supported by manufacturer or spares are available Replacement
Network interruption Health and safety	Mechanical failure (especially electromechanical relays) due to ageing and obsolescence, vibration or drift from set point	Repair if economic and feasible Replacement Regular testing and calibration
Network interruption	Systemic failure - cyber security threats to the external IP network	Communication firewalls at zone substations, and centralised security system Operation Technology Cyber Security Roadmap Design standards

14.9.1.5 Renewal strategy

Protection system upgrades or replacements are most cost-effective when they are linked to projects that involve replacing the associated switchgear as we can minimise outages and use service delivery partners most efficiently. Therefore, our protection system replacement programme is influenced, and in some instances driven, by the schedule of our switchgear replacement or other related work. This is particularly true for our ongoing work of replacing older electromechanical devices with numerical relays, as the electromechanical relays will have been installed with the switchgear and will be replaced with it. Where these renewals are in zone substations, they are included in our major zone substation switchgear renewal projects, rather than in the protection renewal forecasts.

We also use age, type, and obsolescence to help guide protection system replacement. This is particularly the case for replacement of our older numerical relays as the timing of replacement often does not coincide with the associated switchgear renewal due to the shorter numerical lifecycle.

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. Where older (first generation) numerical relays are due for replacement at zone substations we upgrade the protection to our current standards and install arc flash detection. This reduces the risk of asset damage and injury to our staff and service delivery partners.

Table 14.73 Renewal strategy – Protection

Tasks	Description
Renewal trigger	Age/obsolescence Failure Zone substation renewals (where protection renewals is part of larger projects)
Forecasting approach	We forecast proactive renewal volumes of protection assets using asset health
Cost estimation	Volumetric

14.9.1.6 Renewal forecasting approach

We have adopted a volumetric renewal forecasting approach for our protection fleet. This approach involves:

- determining renewal quantity by scheme type using an age-based forecast to proxy the main renewal drivers
- reducing the renewal quantity to account for schemes being replaced as part of zone substation primary equipment renewals
- developing building blocks for average scheme cost (for each type of scheme)
- multiplying quantity by unit rate for each scheme type.

14.9.2 Signalling/communications cables

14.9.2.1 Asset overview

The primary function of signalling/communications cables (SC cables) is to enable protection signalling, and support SCADA and other data communications between substations and our main control centre. There are differential protection relays on each end of a pilot cable, which signal each other using the signalling cables, to accurately determine whether a fault has occurred and its location. These protection schemes are automated systems designed to detect and respond to network faults, ensuring stability and preventing widespread outages.

Our SC cables fleet is made up of two types:

1. **Pilot cables (multi-pair twisted copper)**: a legacy technology laid in building substations and used for SCADA communication and protection signalling to urban substations.
2. **Fibre optic cables**: laid in ducts with most new subtransmission power cables, is now our preferred choice as it has superior data transmission speed and lower signal loss (attenuation) over distance, when compared to pilot cables. Fibre optic cable also avoids issues associated with transferred earth potential because of the use of light signals instead of electrical signals, making them immune to earth potential rise**.**

14.9.2.2 Asset population and age

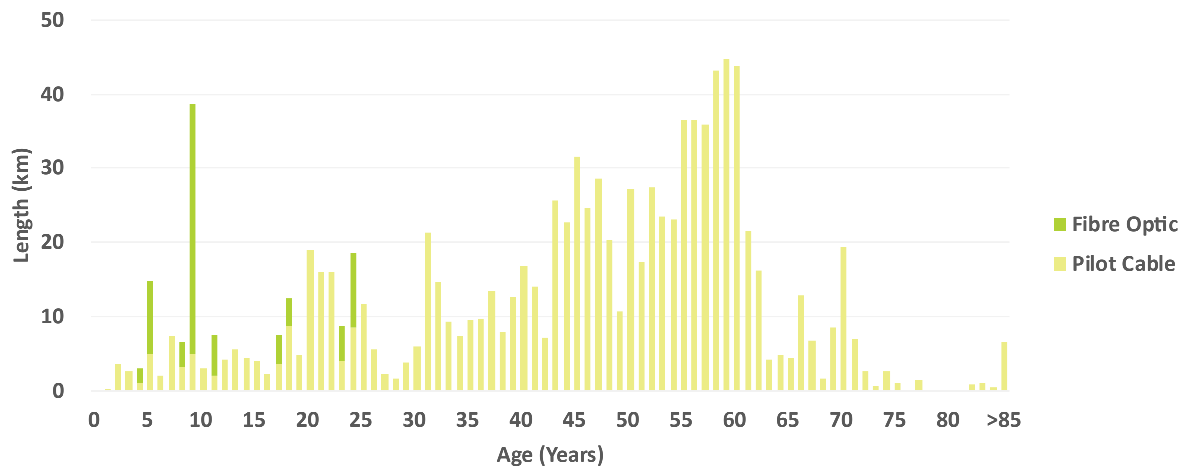
The table below summarises our population of SC cables assets.

Table 14.74 Population – SC cables

Asset type	Approx. Length (km)
Pilot cables	960
Fibre optic cables	77
Total	1,037

The figure below shows the age profile of our SC cables fleet.

Figure 14.77 Age profiles – SC cables

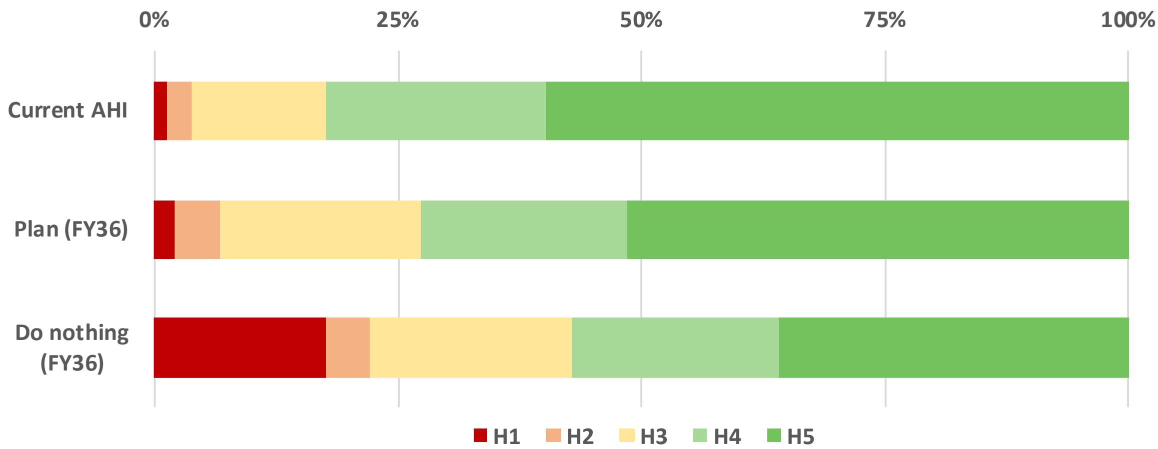


The age spike at 9 years was when we last replaced a portion of our pilot cable network, after they were damaged in the 2011 Christchurch earthquakes. The SC cables are predominantly made up of copper pilot cables which are ageing, with large proportion having been deployed around 50-60 years ago. Fibre optic cables have become more common in recent years.

14.9.2.3 Asset health

We have adopted an age-based Repex approach to derive future asset health for our SC cables. Our AHI for these assets reflects expected remaining life. The figure below sets out an overview of the asset health scores for our SC cables fleet.

Figure 14.78 Asset health – SC cables



Our current level of assets with a H1 score is due to pilot cables exceeding their expected life, being obsolete, are poor performing, running low on spare pairs, and are overdue for replacement. Our renewal programme focuses on the replacement of pilot cables and stabilises overall fleet health. Further deferral of these renewals will increase risk of SC cable failure and increase the risk of protection system maloperation (safety and reliability risk).

Pilot cables come with a varying number of twisted pairs, depending on their capacity. Over time, those pairs can become faulty due to moisture, mechanical damage, or electrical degradation, requiring communication to be shifted to other available pairs. Eventually, as more pairs fail, the cable reaches its capacity limits, leaving no functional pairs available, which forces operators to resort to alternative pilot cable routes or communication methods, such as radio (if there are available licences and no degradation in clearance times is caused) or fibre optics.

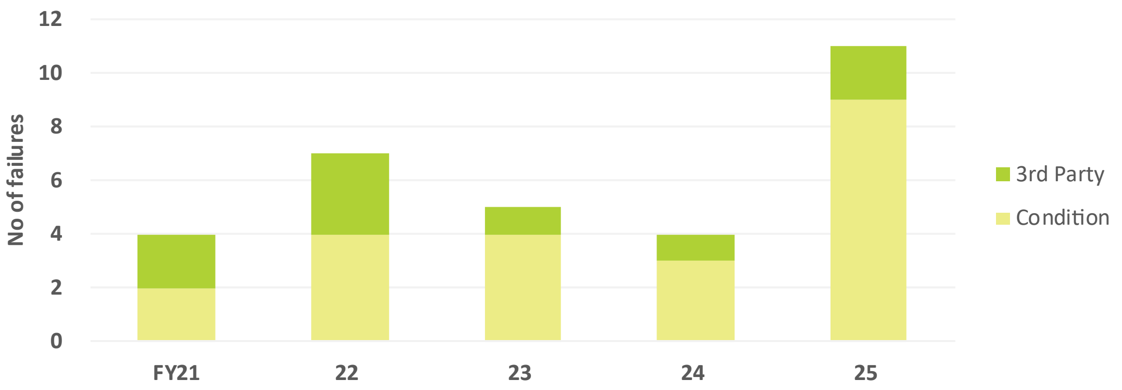
During the 2011 Christchurch earthquake many pilot cables were damaged. Spare copper strands were quickly used up to return the protection system into service and there are likely to be very few spares left by now. Additionally, earthquake stress can further weaken aging pilot cables, increasing the likelihood of failure.

14.9.2.4 Asset performance and risk

SC cables play a crucial role in our network by enabling protection signalling. Failure of protection to clear a fault poses a significant safety risk as it can expose the public and personnel to electrocution as the faulted equipment may still be live. Failure can also cause costly damage to the primary equipment they are associated with. The cables also support ancillary services between substations and our main control centres.

Older pilot cables are causing communication issues within the network due to their deteriorating condition, which is increasing the risk of faults not being detected in real time. A major issue with pilot cables is that early jointing techniques have led to moisture ingress in some joints, which affects the electrical properties of the cables and leads to degraded performance, including attenuation issues on several routes.

Figure 14.79 Number of failures



The figure above shows an increasing trend due to condition failures. Every time a failure happens, we need to use a spare pair, which we are running out of. Condition failures are functional failures that occur when we lose communications, as detected by our network control. Personnel are then sent to the site to investigate; they either have to find the fault and repair it or find a spare pair and reroute.

Third party failures occur when diggers hit or damage our cables during excavation. Most of the time the pilot cables do not appear on available plans as they were built so long ago. When cables are hit or damaged in this way, we must find other spare pairs and/or reroute.

The table below summarises the key risks we have identified for our SC cables fleet.

Table 14.75 Identified risks and mitigations – SC cables

Risk Area	Description	Mitigations
Network interruption Health and safety	Cable failure due to moisture ingress	Routine testing and corrective maintenance of circuits used for unit protection communication
Network interruption Health and safety	Pairs fail to the point that the cable reaches its capacity limits, leaving no functional pairs available	Operators use alternative pilot cable routes or communication methods, such as radio (if there are available licences and no degradation in clearance times is caused) as a temporary measure or replace with fibre optics
Network interruption	Lack of pilot cable spare pairs	Use alternative pilot cable routes if available, otherwise replacement is the only option
Network interruption Health and safety	Earthquake stress could further weaken ageing pilot cables, increasing the likelihood of failure	Replace with fibre optic cables, where possible
Legal/regulatory compliance	We are subject to certain legislation on protection clearance times. Any breaches and/or safety incidents will be investigated, and possibly prosecuted, by WorkSafe The protection clearance requirement under EIPC is enforced by the Electricity Authority	Our protection system uses SC cables to enable differential protection to meet those legislative requirements

14.9.2.5 Renewal strategy

Our pilot cables were significantly damaged during the Christchurch earthquakes, such that some of them have few spare cores or copper pairs. Any further damage to these cables will mean they need to be replaced, generally with fibre optics cable.

When signalling cable is replaced, and it is co-located with distribution cable, we replace both signalling and power cable. Where we have two protection signalling cables installed in the same trench, we replace them with one larger cable. Some pilot cables share the same trench, so we consolidate the pilot cable lengths, i.e. if there are two pilot cables running on the same route, we group them together and replace them with one larger cable with more pairs.

Our other options for renewing SC cables include:

- **installing fibre through leased ducts:** new fibre cable will be installed in leased third party ducts, some trenching will still be required as the third-party ducts typically do not begin / end where our equipment needs to be terminated, and
- **open trenching:** new fibre cable will be installed via an open trench method.

We cannot rely on radio or third-party fibre cable (via local telco providers), as there is uncertainty around reliability (i.e. interference) of the signal and transmission speed. Also, radio is impractical in urban areas due to the lack of availability of radio licences and potential bandwidth limitations.

While it is possible to use other fibre networks, there are cybersecurity concerns and additional considerations, such as coordinating work on their network and understanding their networking routes. Using our own fibre optics cable also provides the flexibility to run other services, such as cameras, unmanned aerial vehicles and door locks. An exception to this may be rental of ‘dark’ fibre with routes near our equipment. Use of dark fibre is something that may be considered in the future.

Age provides a good proxy for condition for this fleet. Older cables are less likely to have spare copper pairs, and more likely to have suffered damage from earthquakes or moisture ingress.

Table 14.76 Renewal strategy – SC cables	
Tasks	**Description**
Renewal trigger	Condition Failure
Forecasting approach	We forecast proactive renewal volumes of SC cable assets using a Repex approach
Cost estimation	Volumetric

14.9.2.6 Renewal forecasting approach

We have adopted a Repex approach to forecasting renewals. This approach involves:

- determining a distribution of the age at which replacement is required (using a normal distribution) for the SC cable population as a whole.
- applying the resulting probabilistic replacement rate curve to the current asset age profile to predict the future number of replacements. The age profile considers a consolidated cable route, where some pilot cables share the same route and we assume both cables are replaced with a larger cable with more pairs.
- reducing the distribution cable (trenching) cost for the proportion of the renewals where the work will be done alongside SC cable renewals.

Costs are estimated using a volumetric approach. Unit rates are based on an estimated average, covering costs over a wide range of brownfield conditions. We anticipate that a significant portion of signalling cable renewals will be in shared trenches with distribution power cables which also require renewal. When replacing signalling cables, we will either install fibre through leased ducts or a new trench with ducts with the former incurring an ongoing leasing cost.

14.9.3 SCADA (RTUs)

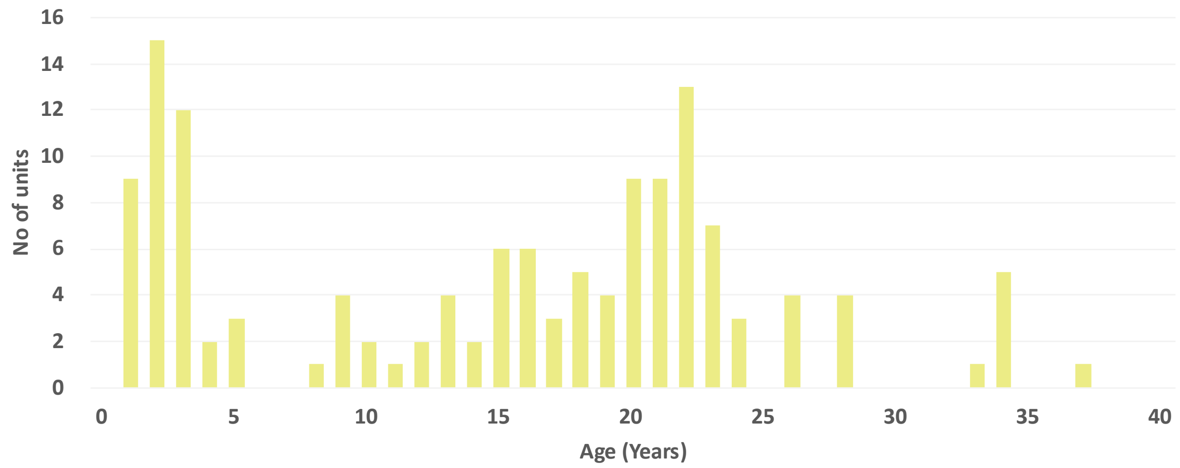
14.9.3.1 Asset overview

Our SCADA system provides control and visibility of our electricity distribution network in real time. We have SCADA assets in zone substations and in the field. This fleet comprises RTUs, and associated assets. The RTU is the field device installed at the remote substation that interfaces network objects in the physical world with the SCADA master station, using a communications network.

14.9.3.2 Asset population and age

The population of SCADA RTUs is approximately 140. RTUs have an expected life of 20 years; about 40% of the fleet have exceeded this age and are no longer supported by their manufacturer. The figure below shows the age profile of our SCADA fleet.

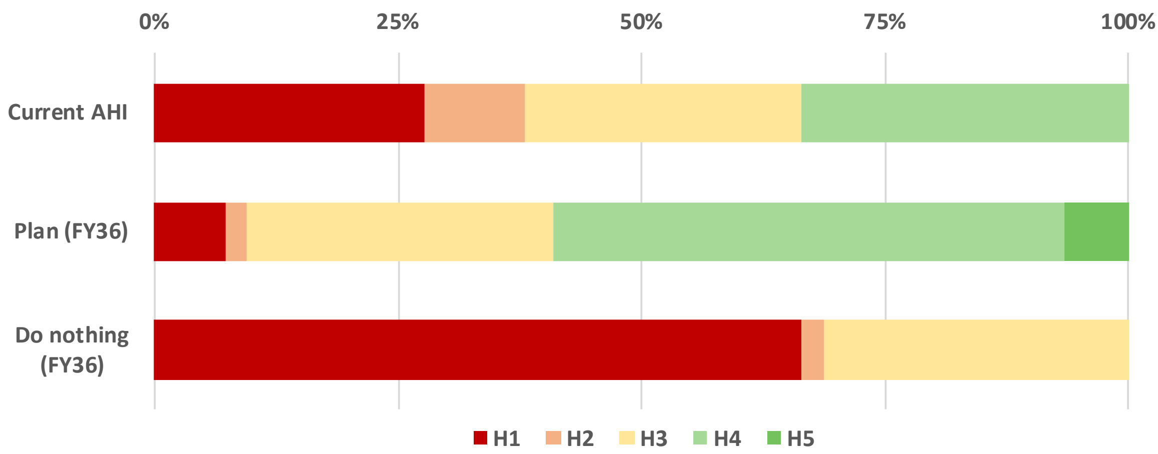
Figure 14.80 Age profiles – SCADA



14.9.3.3 Asset health

We have adopted an age-based approach to derive future asset health. The figure below sets out an overview of the asset health scores for our SCADA fleet.

Figure 14.81 Asset health – SCADA



The main driver for the SCADA fleet H1s is due to technological obsolescence and discontinued manufacturer support. Typically, these RTUs are older and exceed their expected life. Over the AMP period, we will prioritise replacements of these obsolete RTUs and improve overall asset health. This will improve reliability risks by continuing to supply our SCADA system with the necessary data to monitor the network efficiently. Further deferral of RTU renewals will increase our obsolescence risk, which may lead to lower visibility of the network and inhibit network operations and restoration after an outage.

14.9.3.4 Asset performance and risk

The SCADA assets are performing adequately at present. The CPUs in some of our RTUs types are obsolete and are no longer supported by their manufacturers. We expect some RTUs types will fail imminently as their capacitors only have a life of 20 years, and they are also obsolete. These units are progressively being replaced as we undertake other upgrades at substations.

The table below summarises the key risks we have identified for our SCADA fleet.

Table 14.77 Identified risks and mitigations – SCADA

Risk Area	Description	Mitigations
Network interruption	RTU malfunction or failure in service leads to lack of remote control.	Inspection and test regime Alarms and monitoring Renewal
Network interruption	Cyberattack	Cybersecurity measures Regularly patching software

14.9.3.5 Renewal strategy

RTUs have an expected life of 20 years; many have exceeded this age and are no longer supported by their manufacturer. We will progressively replace them as we undertake other projects at zone and distribution substations.

Table 14.78 Renewal strategy – SCADA

Tasks	Description
Renewal trigger	Age
Forecasting approach	We forecast proactive renewal volumes of SCADA assets using an age-based approach
Cost estimation	Volumetric

14.9.3.6 Renewal forecasting approach

We use an age-based approach to forecasting renewals of RTUs.

14.9.4 Communications

14.9.4.1 Asset overview

Our communication network data systems provide services essential to the operation and protection of our distribution network, including protection signalling and remote indication and control of network equipment.

Our communications system is made up of two types:

1. **Digital subscriber line (DSL) system**: used for point-to-point links and protection between substations utilising private copper communications, where available. Various urban links are arranged in four rings to provide full Internet Protocol communication redundancy to each substation

   Ultra-High Frequency Internet Protocol 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.

14.9.4.2 Asset population and age

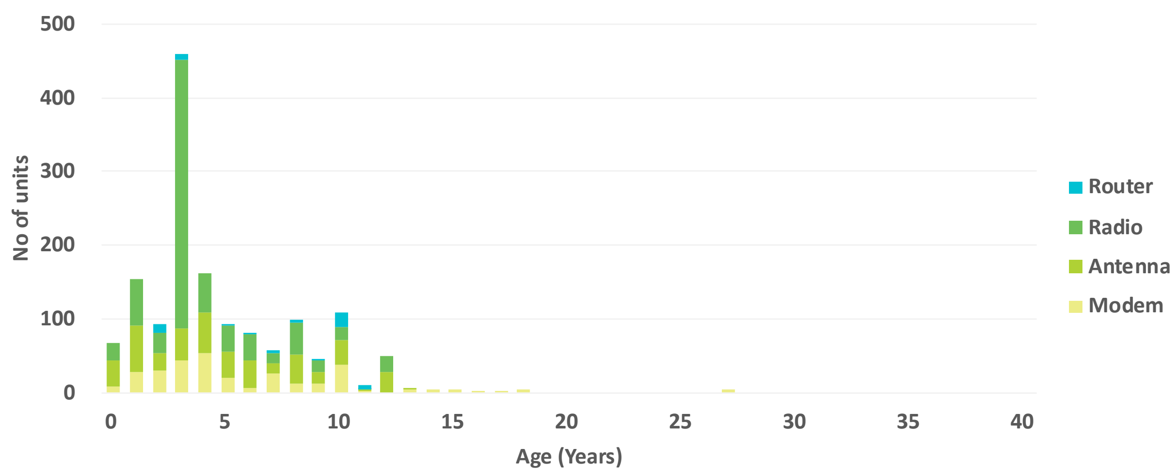
The table below summarises our population of communications assets by type.

Table 14.79 Population – communications

Asset type	Population (approx.)	Expected life
Modems	305	8 years
Radios	720	12 years
Antennae	425	15 years
Routers	60	10 years
Total	1,510	

The figure below shows the age profile of our communications fleet.

Figure 14.82 Age profiles – communications



Most of our communications assets are within their expected lives. However, a substantial number of our modems have exceeded their expected life; we have a programme in place to replace this equipment. Many are becoming obsolete due to discontinued support by their relevant manufacturers and also becoming superseded by new technology. We are managing this risk through our spares stock and system redundancy.

14.9.4.3 Asset health

It is not practical to obtain condition information for communication assets due to their electronic nature. Instead, we use age as a proxy for condition and obsolescence.

14.9.4.4 Asset performance and risk

The communications network is generally reliable 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.

Table 14.80 Identified risks and mitigations – communications

Risk Area	Description	Mitigations
Network interruption	Comms failure leading to loss of visibility and control.	Diverse communication paths. Preventive maintenance. Renewal programme.
Network interruption	Cyber-attack	Cybersecurity preventive measures Regularly patching software

14.9.4.5 Renewal strategy

Due to rapid improvement in technology, communications equipment can have relatively short lifecycles with manufacturer support ending, leading to obsolescence. To cater for this our communication systems renewal programmes are driven by projected asset obsolescence and reduction in the availability of spares and support.

Table 14.81 Renewal strategy – communications

Tasks	Description
Renewal trigger	Age.
Forecasting approach	We forecast proactive renewal volumes of communications assets using an age-based approach.
Cost estimation	Volumetric – type based.

14.9.4.6 Renewal forecasting approach

We use an age-based approach to forecast renewals, as age is a reasonable proxy for communications equipment failure and obsolescence.

14.9.5 Batteries and DC supplies

14.9.5.1 Asset overview

DC systems are critical components of our network as they provide uninterrupted standby energy, for the reliable operation of switchgear, protection, control and communication systems. They continuously power some systems and assets, as well as providing power for a minimum period following an AC supply loss. They are located at zone substations and in the distribution network.

Each DC system comprises:

- a series battery string comprising DC batteries to make up the nominal voltage, and
- chargers, also known as rectifiers, as they turn AC into DC power to charge the battery.

DC systems at our zone substations are typically 110 V (to serve our protection equipment) and have redundancy (N-1) of both batteries and charger, so that the failure of a cell or charger does not result in loss of substation control and protection.

The environment is temperature-controlled, with heating and cooling used to avoid the large temperature variations that reduce battery life. For DC systems located in distribution substations, we similarly utilise temperature control, but do not have redundancy in most cases. These systems are typically lower voltage, for SCADA and communications. All chargers are alarmed, so we can replace them immediately, should they fail.

14.9.5.2 Asset population and age

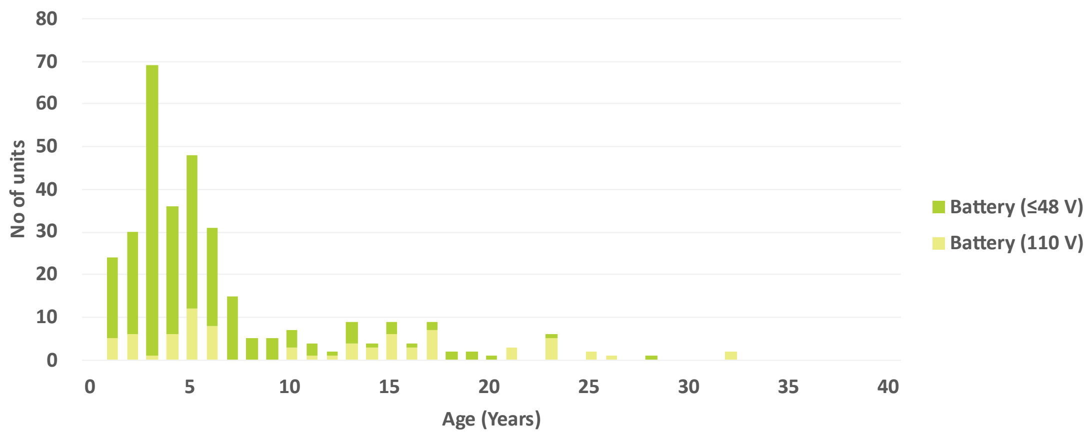
The table below summarises our population of batteries and DC supply assets by type. Most batteries are lead acid types, with a smaller number of gel and valve regulated lead acid types.

Table 14.82 Population – batteries and DC supplies

Asset type	Population (approx.)	Expected life
Battery (≤48 V)	330	8 years
Battery (110 V)	80	12 years
Total batteries	410	-
Chargers	337	15 years

The figure below shows the age profile of our batteries and DC supplies fleet.

Figure 14.83 Age profiles – batteries and DC supplies



More than 20% of the fleet have exceeded their expected lives.

14.9.5.3 Asset performance and risk

Batteries and DC supplies provide DC supply to protection relays, SCADA and communications equipment, and/or operate circuit breaker trip coils. Failure of a battery or DC supply can lead to an interruption or unplanned outage. This occurs when there is a fault in the network: if the batteries fail and the DC system is unable to supply the trip coils, the circuit breaker is unable to open and clear the fault. This can have a wider than expected impact on the network, as protection further upstream will be required to clear the fault.

Many of our batteries have exceeded their expected lives, increasing risk of our DC systems failing to operate switchgear. When we regularly test them, in addition to testing their ability to open/close circuit breakers (part of primary plant maintenance), we will replace the batteries if they fail these tests. Chargers are monitored through alarms to our SCADA system, if these alarms trip we will investigate and replace the chargers or modules. Otherwise these assets are generally planned to be replaced when they exceed their expected life.

Table 14.83 Identified risks and mitigations – batteries and DC supplies

Risk Area	Description	Mitigations
Network interruption	DC system fails in service leading to protection maloperation, no visibility or network control.	Regular testing Redundancy (N-1) at zone substations Temperature-controlled substation environments Alarmed chargers Renewal
Network interruption Health and safety	Catastrophic battery failure, i.e. thermal runaway, leading to fire.	Alarms and monitoring Renewals Installing fire systems

14.9.5.4 Renewal strategy

We replace batteries based on age or when they fail their discharge test. Chargers are replaced if they fail in service or when they exceed their expected life.

Table 14.84 Renewal strategy – batteries and DC supplies

Tasks	Description
Renewal trigger	Age Failed discharge test
Forecasting approach	We forecast proactive renewal volumes of batteries and DC supply assets using an age-based approach
Cost estimation	Volumetric

14.9.5.5 Renewal forecasting approach

We use an age-based asset health model for forecasting renewals, with expected lives of 8, 12, and 15 years for <48 V and 110 V batteries and chargers, respectively. As a considerable number of chargers and batteries are nearing, or past, their expected life, we expect to replace a considerable number in the near term.

14.9.6 Metering

14.9.6.1 Asset overview

Our monitoring assets are high voltage (11 kV) GXPs metering equipment, and power quality meters. These assets cover four areas in our network:

1. **High voltage (11 kV) customer metering**: we own metering current transformers (CTs) and voltage transformers (VTs) along with associated test blocks and wiring at approximately 45 customer sites. Retailers connect their meters to our test blocks. All Orion metering transformers are certified as required by the Electricity Governance Regulations 2003.
2. **Transpower metering**: we own metering equipment at Transpower's GXPs. The data from our meters serves as input into our SCADA system for load management and as check meters should Transpower's meters fail.
3. **Power quality monitoring**: we have installed some permanent, standards-compliant, power quality measurement instruments across a cross-section of distribution network sites with varying load types. Data collected is analysed to assess long-term trends in performance and to assist in the development of standards and regulations and future power quality improvement projects.
4. **LV monitoring**: we have installed approx. 900 LV monitors across our LV network to gain better visibility. LV monitoring provides us with real changes in network usage and helps us to plan future development of the LV system.

14.9.6.2 Asset population and age

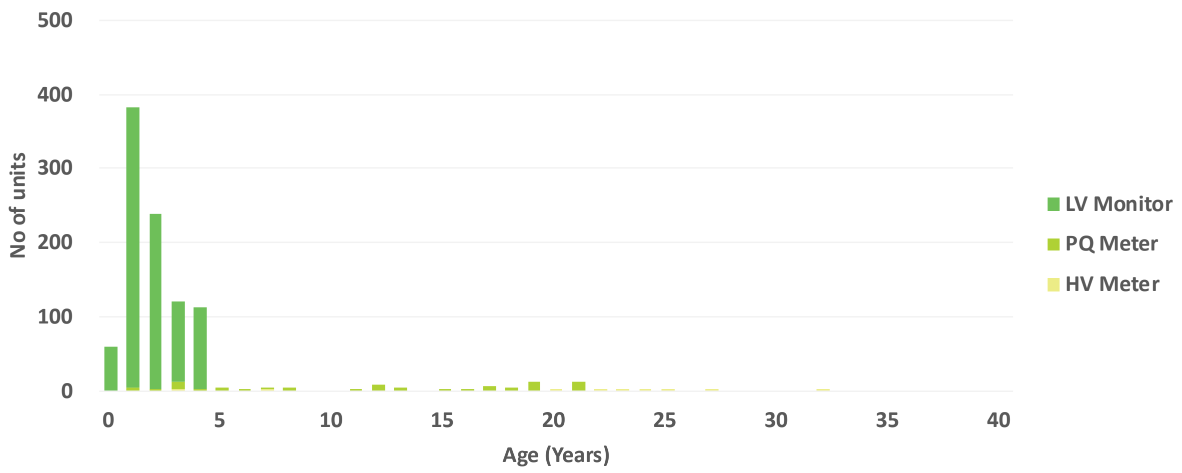
The table below summarises our population of metering assets by type (excluding Transpower owned metering).

Table 14.85 Population – metering

Asset type	Population	Expected Life
HV meter	20	30 years
LV monitor	890	13 years
Power quality meter	80	15 years
Total	**990**	

The figure below shows the age profile of our metering fleet.

Figure 14.84 Age profiles – metering



Many of our power quality meters are at end of life because our approach has been to replace them upon failure as they are quick to replace and non-critical. However, we are moving to a more proactive renewal approach, starting with those that will exceed their expected lives over the AMP period. About half of our HV meters have already reached, or will reach, end of life in the next decade.

14.9.6.3 Asset performance and risk

Metering transformers are extremely reliable standard components of high voltage switchgear. We check our non-revenue metering data against Transpower's data. If there is a significant difference, meter tests may be required to understand where the discrepancy has occurred. Our power quality meters support a proactive approach to improving network performance. They have performed well to date, with many exceeding their expected life.

Table 14.86 Identified risks and mitigations – metering

Risk Area	Description	Mitigations
Compliance or regulatory	GXP revenue metering failure	Reconciliation of data Metering calibration Renewal

14.9.6.4 Renewal strategy

Metering assets are considered non-critical, and typically, a reactive approach is employed to identify necessary replacement work. However, we have implemented a capital expenditure programme to proactively replace our power quality meters, many of which are well past their expected life.

We replace metering transformers as part of our switchgear renewals programme.

Table 14.87 Renewal strategy – metering

Tasks	Description
Renewal trigger	Age
Forecasting approach	We forecast proactive renewal volumes of metering assets using an age-based approach
Cost estimation	Volumetric

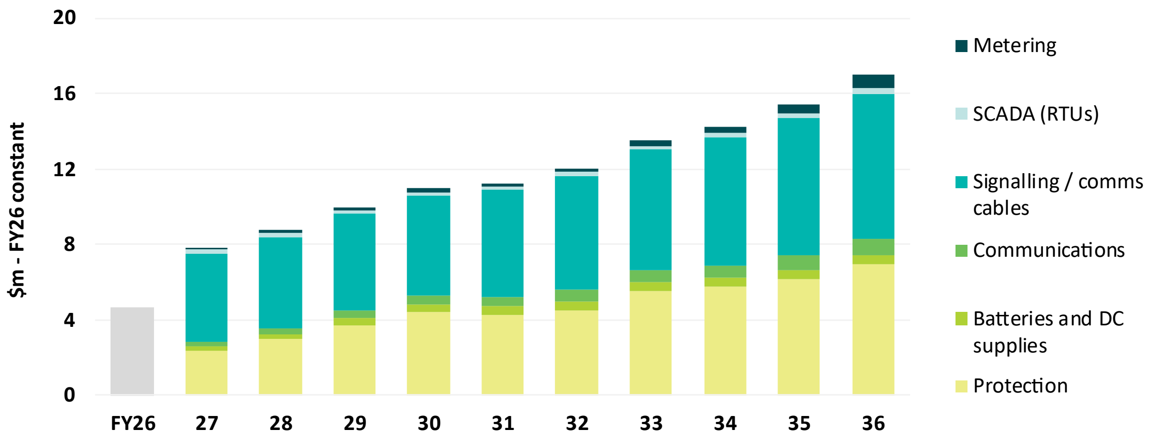
14.9.6.5 Renewal forecasting approach

We use an age-based approach to forecasting metering and monitoring renewals, using expected lives.

14.9.7 Secondary systems forecast capex

The following figure shows our forecast capex for secondary systems.

Figure 14.85 Planned secondary systems renewals capex



We will gradually increase our protection investment over the AMP period as more protection relays become due for replacement. Firstly, focusing on replacing protection schemes in zone substations, then moving onto distribution protection relays later in the AMP period. The main reason for the investment is the aging fleet of relays. Replacement of protection relays is typically done at the same time as primary equipment renewal as this is more cost effective. However, the shorter life of relays means they often need to be replaced independently of other assets. The amounts here exclude protection schemes replaced as part of zone substation primary equipment renewal.

Our SC cables forecast is comprised mainly of replacement of pilot cables. These pilot cables will be replaced with modern fibre optics, which we may install directly through open trenches or blown through third party ducts where available. The latter is more cost effective, however third-party ducts are not always available or do not run near our equipment. We will gradually increase our level of pilot cable replacements over the AMP period, as more of these cables exceed their expected life or run out of spare pairs.

The remaining expenditure for the other fleets are relatively small but necessary to effectively manage the respective fleets.

14.10 Expected benefits

The expected benefits of work over the AMP period are:

- **Risk management**: the planned activities will reduce risk and maintain/improve asset health and performance of the fleets. Examples include:
  - outdoor and indoor switchgear fleets will be less likely to have insulation failures, which can be catastrophic and potentially damage nearby assets, particularly for oil insulated assets where the risk of fire is increased
  - indoor switchgear fleet will have less ageing 11 kV oil-interrupted circuit breakers. Failure of these assets, while rare, could be catastrophic, with the potential to cause injury to operators

- ground mounted switchgear fleet will include fewer RMUs with a safety type issue. Those units have had 10 failures over the past 7 years (of which two were catastrophic) resulting in an abnormally high failure rate compared to other types
- protection relays will be upgraded to current standards, with arc flash detection installed.

- **Ensuring reliability**: a reduced number of unplanned faults and failures on the overhead and underground network due to asset failures will maintain overall reliability. Examples include:
  - reducing likelihood of critical subtransmission conductor failures reduce the risk of large outages
  - protection, longer fault durations, costly asset damage, and larger outages which affect more customers can be avoided
  - enclosures, ensuring safe housing of network assets will improve overall reliability
  - SC cables, lower losses in signal strength, resulting in reduced fault hazards, will at least maintain overall reliability
  - distribution conductor, converting these assets to cables can improve reliability
  - crossarms, a large portion of our crossarms are in poor condition having exceeded their expected life.
- **Improved safety**: a reduced risk of exposing staff, service delivery partners, and members of the public to safety risks associated with failures. Examples include:
  - reducing likelihood of conductors dropping, poles falling, protection systems not being able to isolate the network effectively, arc flash hazards from ground mounted switchgear failures, especially with older oil-filled switchgear, unfused MSUs, and type issue RMUs
  - converting some large pole mounted transformers to ground mounted units will reduce the need for working at heights. Safety risks related to earthquakes will also be reduced
  - designing ground mounted infrastructure (kiosks and distribution boxes) for safe use in public areas, including ensuring they are safe to touch
  - decreasing the number of buildings that are below our seismic standards
  - replacing overhead assets, i.e. distribution conductor, in high density areas, such as around schools or high-density population areas, can improve safety as the consequences of failure are greater.
- **Environmental**: minimising fire risk from fuse operation in pole mounted switchgear, due to the sizable programme of work to replace fuses in rural areas/areas with dry grass with sparkless fuses, and by replacing poles at a high risk of wildfire. These programmes will also improve safety.
- **Greater resilience**: replacing or converting certain assets will have a positive impact on resilience of our network. Examples include:
  - a reduced number of poles, crossarms, and subtransmission, distribution, and LV conductor in poor condition will increase the resilience of the overhead network to extreme weather, i.e. high winds and flooding
  - reduced numbers of wildfire risk poles will improve the resilience of the overhead network to wildfire
  - a reduction in the number of oil-filled subtransmission cables will increase the seismic resilience of the underground network
  - the conversion of outdoor switchgear to indoor will result in a reduced number of assets being exposed to the weather. This will increase the resilience of the overhead network to extreme weather, i.e. high winds and flooding

- increasing the number of buildings that meet 67% of the NBS will increase the seismic resilience of our zone substation buildings
- a new distribution box design will increase the resilience of those boxes to flooding, while increased seismic strength in our distribution substations will increase the resilience of the network to earthquakes, as well as improving safety
- conversion of some large pole mounted transformers to ground mounted transformers will result in a reduced number of assets being at risk during earthquakes, extreme weather, and lightning strikes. This will increase the resilience of the overhead network to these events
- replacing signalling/communications pilot cables with fibre optic cables will improve the resilience of the network to earthquakes
- replacing generators will mean a reduced risk of supply interruptions to our building and other essential infrastructure in the event of an emergency.

• **Improved data**: by collecting more data, and analysing historical data, for the asset health and performance of the overhead fleets we will improve our understanding of these assets, resulting in better decision making.

• **Improved functionality**: Examples include:
  - replacing pilot cable with fibre optic cable, where possible, will result in improved functionality, such as faster transmission speeds and larger bandwidth. Carrying out renewals ahead of a large proportion of the pilot cable population reaching the end of its expected life will also increase the capability of the distribution network
  - replacing older electromechanical devices with modern numerical relays as this will increase discriminant safe isolation of the network and faster protection clearance, by integrating protection, control, and metering into a single numerical relay. This functionality also provides reliability and safety benefits.

• **Improved efficiency/flexibility**: replacing manually operated MSUs with RMUs will increase network control, visibility (as these will become SCADA enabled), and automation. This will also enable faster network restoration following a fault.

• **Compliance**: we will meet our obligations with respect to management of under clearance violations for our subtransmission, distribution, and LV conductor fleets. There will also be a reduced risk of non-compliance with the ESR and EIPC in relation to our SC cables fleet.

• **Cost effective**: planned renewal work is generally more cost effective than reactive works. We will replace some small towers with monopoles at end of life as this will reduce ongoing maintenance/refurbishment costs. Painting towers before significant degradation occurs, is also cost effective. As we phase out our oil-filled switchgear fleet there will be reduced maintenance and servicing costs. We also refurbish power transformers when they exceed half their expected life. Undertaking this work means that their operating life is extended, which defers the need for large renewal capex projects proving a cost and timing benefit.

• **Customer experience**: replacing the RMUs that have a type issue will mean that fewer customers are impacted due to switching restrictions in planned operations.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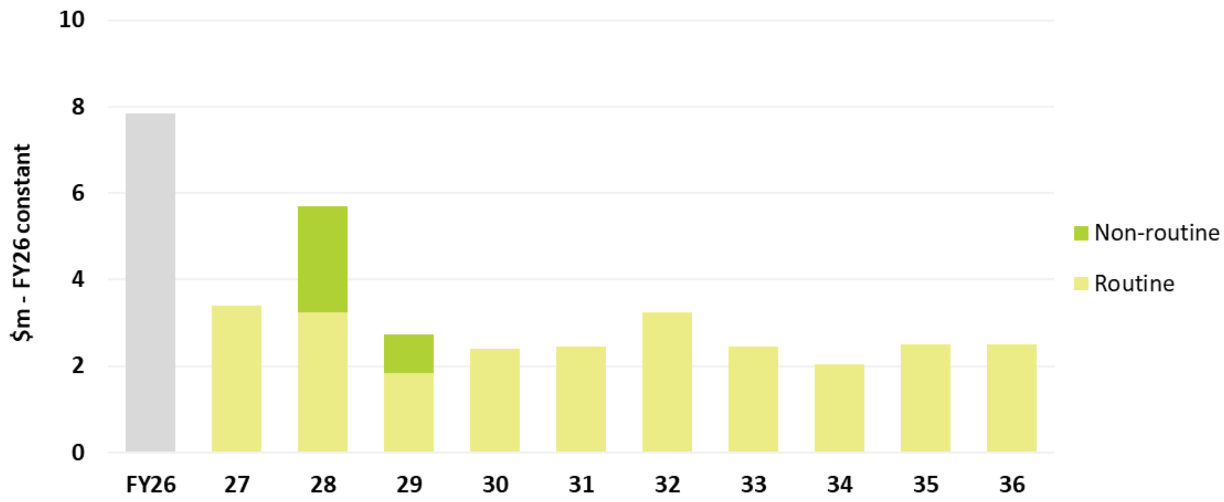
15. Managing our non-network assets

This section describes how we manage our non-network assets, including corporate properties, motor vehicle fleet, and tools and equipment, through their lifecycle.

15.1 Investment overview

Our total non-network capex investment[59] totals $29.4m over the FY27-FY36 period. Figure 15.1 shows the total planned capex expenditure per annum.

Figure 15.1 Orion's total non-network capex per annum



The capex is made up of the following components:

- **Routine corporate capex**: ongoing lifecycle replacement of corporate assets, such as vehicles and tools, and office fit outs that support day-to-day operations.
- **Non-routine corporate capex**: discrete capital projects that enhance our operational infrastructure. This includes establishing a fuel-storage facility and oil refurbishing facility to improve our operational self-sufficiency and environmental management, and expanding our head office capacity to accommodate the additional staff required to deliver our investment programme.

Spending steps up in FY26 and FY27 due to the staged fit-out and refresh of our head office. It increases further in FY28 as we expand our head office capacity and complete planned facilities investments. Expenditure then stabilises over the remainder of the AMP period as these one-off programmes conclude and spending returns to a more routine level.

15.2 Forecasting approach

We have used a bottom-up build approach to forecast non-network capex. This ensures our forecast directly reflects our expected needs over the AMP period, and allows us to test the prudence and efficiency of each expenditure component. Although a 'base-step-trend' forecasting approach can often be used to forecast this type of expenditure, given the expected step up in delivery activity and business scale over the AMP period, we did not consider that trending from historical spend was appropriate.

[59] Excluding ICT and Network Transformation investment. These are captured in Section 8 – People and technology and Section 9 – Transforming our network, respectively.

At a high level this forecasting method involves combining forecasts for each of the following:

- **Corporate buildings and facilities**: forecast spend based on needs assessment and planned works to maximise ongoing utilisation of the existing space, with a business case assessment used for a one-off investment to lease additional office space
- **Fuel storage facility**: based on estimates and quotes provided to establish the facility
- **Oil storage and handling facility**: based on estimates to establish the facility
- **Vehicles**: assumed replaced on like for like basis upon reaching year or mileage thresholds set for vehicle type, including allowance for modest fleet growth over the period to meet the needs of our growing workforce
- **Tools and equipment**: forecast based on historical spend with replacement programmes and some known additions.

15.3 Corporate buildings and facilities

Our corporate properties provide the physical base from which we operate, housing our people, equipment, and contingency capabilities. This section describes the assets that make up this portfolio, how we maintain them, and the material capex investments planned over the next five years.

15.3.1 Asset overview

We own and lease a portfolio of corporate properties that house our people, operations, and equipment across greater Ōtautahi Christchurch. Our portfolio includes our head office, leased satellite office spaces, and a contingency operations centre. We also own an office and depot that is leased to our subsidiary,[60] who is responsible for its upkeep and maintenance under that arrangement.

Our head office building was constructed 12 years ago, following the Canterbury earthquakes. It was constructed to a IL4 standard, designed to remain operational following a 1 in 500-year seismic event.[61] The building includes a standby generator and diesel tank to provide backup power for critical operations during emergencies; refer to Section 14.8.4 – Generators for further detail on these assets.

Our contingency operations centre can be activated if our head office is unavailable. It provides backup capability for continued network operations and the option of separating key personnel during pandemic events. Critical spares for essential equipment, including power transformers, key switchgear components, subtransmission cables and accessories, and communications and SCADA equipment, are held at this facility along with 3.5 MVA of transportable diesel generation.

15.3.2 Maintenance approach and renewal strategy

We manage the corporate properties we are responsible for to ensure they remain safe, functional, and fit for purpose. As mentioned above, our head office has been in service for 12 years. In FY26 our head office had a routine fit-out and refresh programme covering carpets, paint, fixtures and common areas to ensure the building remains functional and that available space is efficiently utilised. We estimate ongoing investment of approximately $150,000 per year for routine upgrades and modernisation.

Our contingency operations facility is maintained as functional operational space within our Papanui zone substation. Upkeep is managed as part of routine substation property maintenance and no material renewal of the facility is anticipated within the AMP period.

No material maintenance or renewal projects beyond this programme are planned for buildings and facilities within the next five years.

[60] Our subsidiary is Connetics Limited, who operate as an arms-length independent business.

[61] IL4 refers to Importance Level 4 which applies to essential buildings, including lifeline infrastructure. As a lifelines utility, under the Civil Defence Emergency Management Act 2002, we are required to remain operational after HILP events.

15.3.3 Material capex projects

Three material capex projects are planned within the next five years for this portfolio, as summarised in Table 15.1. The following sections describe each project in more detail.

Table 15.1 Material capex projects – corporate buildings and facilities ($m, FY26 constant)

Project	Description	Forecast cost	Timing
Head office capacity expansion	Lease satellite office space for up to 50 people	$2.3	FY28
Fuel storage facility	Install new diesel fuel storage facility at Papanui zone substation	$0.6	FY29
Oil storage and handling facility	Install new transformer oil refurbishment and ester oil storage facility	$0.5	FY28 – FY29
Total		**$3.4**	

15.3.3.1 Head office capacity expansion

Our head office is approaching its occupancy capacity as our team grows to deliver our planned work programme. Our preferred solution is to lease satellite office space for up to 50 people by the beginning of FY28. This provides a flexible, low-disruption path to managing near-term capacity constraints while longer-term options are explored.

The preferred option was identified through a structured options assessment and business case that evaluated the costs and benefits of alternative solutions, including a do-nothing option.

15.3.3.2 Fuel storage facility

Diesel supply is an essential part of Orion's operational recovery and mobility and must be prioritised as part of our planning efforts. Recent events on the North Island reinforced how important it is for distribution businesses to ensure their networks can both withstand and respond effectively to major events. To strengthen our emergency readiness, we are establishing a diesel fuel storage facility at our Papanui zone substation site.

The facility will involve the installation of two diesel fuel tanks and a set down area for four fuel cube mobile units, providing a reliable fuel supply for the Papanui site generator, fleet response vehicles, generator trucks, and generators during major outages.

15.3.3.3 Oil storage and handling facility

We are investing in a dedicated oil storage and handling facility to support two operational requirements

First, we will expand our transformer oil refurbishment capability: our existing equipment has limitations that result in approximately 24,000 litres of oil being disposed of each year. A more capable facility will allow us to fully refurbish transformer oil, removing contaminants such as oxidation products, particulates, gases, and moisture, providing a sustainable and cost-effective alternative to replacement oil.

Second, we will provide appropriate storage and handling for ester oil. For some larger ground-mounted transformers located close to combustible structures, we are transitioning to ester-oil compatible units at end of life where appropriate, as described in Section 14.8 – Distribution transformers. Ester oil has significantly lower flammability than mineral oil and is non-toxic and biodegradable within 21 days.

15.4 Motor vehicle fleet

Our vehicle fleet is essential to delivering safe and reliable network operations, enabling our people to maintain and respond to faults and emergencies across our network area around the clock. This section describes the fleet, how we manage and replace it, and our forecast investment over the AMP period.

15.4.1 Asset overview

We own our fleet outright rather than leasing, giving us greater control over vehicle specification, fit-out to our operational standards, and disposal timing. Our fleet comprises 104 vehicles, including:

- 4 heavy vehicles (6 - 14 tonne trucks with generators ranging from 110 kVA to 550 kVA)
- 25 operation utility vehicles (all four-wheel drive diesel with well-side and canopy or service body configuration)
- 50 operation other vehicles (i.e. SUVs, wagons, and sedans)
- 25 other vehicles.

Vehicle selection is guided by fitness for purpose, safety (all vehicles must achieve a minimum five-star ANCAP crash safety rating), reliability, sustainability and fuel economy, whole-of-life value, and fleet diversity to spread operational risk.

Currently, our passenger fleet is 77% electric with a mix of full EV and hybrid EVs. Heavy-duty vehicles, including generator trucks and operational utilities, remain diesel-powered where no fit-for-purpose electric alternative is currently available. We maintain a watching brief on the evolving heavy vehicle market and will continue to progress electrification as viable options emerge.

15.4.2 Maintenance approach and renewal strategy

All vehicles within their warranty period are serviced in accordance with the manufacturer's recommended service schedule by the manufacturer's agent. Vehicles outside their warranty period are maintained in accordance with manufacturer specifications by a contracted service agent. All vehicles are fitted with GPS tracking systems to support safety monitoring and operational performance oversight.

Fleet replacement follows a risk-based approach considering a vehicle’s age, condition, distance travelled, maintenance costs, and fitness-for-purpose. Vehicles are replaced on a like-for-like basis upon reaching their designated age or distance threshold, unless the driver’s operational needs have changed; in which case the vehicle type is adjusted accordingly at the point of replacement.

Vehicles are disposed of via auction to achieve market value at minimum administrative cost.

Replacement cycles by vehicle type are set out in Table 15.2 below.

Table 15.2 Vehicle replacement cycles

Type	Replacement cycle
Operation utility vehicles	5 Years or 200,000 km
Operation other vehicles	6 Years or 140,000 km
Other vehicles	4 Years or 100,000 km
Heavy trucks	10 Years or 200,000 km

15.4.2.1 Material capex projects

Our vehicle fleet is replaced on a rolling, scheduled basis in accordance with the replacement cycles set out in Table 15.2. This programme does not give rise to discrete material projects but does represent our most significant source of routine non-network capex over the AMP period.

We are also planning modest fleet growth of 3 utility service vehicles and 7 operational vehicles across the AMP period, reflecting increased field activity to deliver the CPP programme and the requirements of forecast workforce growth.

There are no material one-off vehicle capex projects planned within the next five years beyond the ongoing replacement programme described above.

15.5 Tools and equipment

Our field operations team relies on a range of tools and specialised equipment to operate and maintain the network, respond to faults and emergencies, and deliver our planned works programme safely and efficiently. This includes operational tools used by our in-house field operators and equipment supporting our service delivery partners.

Tools and equipment are managed on a risk-based replacement approach, with renewal triggered by condition, end of serviceable life, obsolescence, or changes in operational requirements that affect fitness for purpose. An ongoing budget is maintained for unforeseen replacements, supplemented by planned programmes for higher-value or specialised items where replacement needs can be identified in advance. There are no material one-off capital or maintenance projects planned for this portfolio within the next five years.

16

16. Our investment programme

This section begins by reviewing our recent performance against the commitments set out in our previous full AMP in 2024, covering our financial, project, and programme delivery performance for FY25 and how our investment profile has changed.

The remainder of the section sets out the capital expenditure (capex) and operational expenditure (opex) we intend to invest over the next 10 years. The forecasts are grounded in data, modelling, and cost-estimation practices and are supported by business cases for major projects and robust governance challenge ensuring alignment to business strategies and customer insights. We have also captured forecast efficiencies in our non-network expenditure for the implementation of integrated asset management system.

This AMP reflects our best current view based on the information available today; however, we do recognise there are uncertainties that could materially influence future expenditure, such as electrification trends, growth timing, and regulatory changes. These are key drivers that we actively monitor, and our sensitivity analysis for major system growth and renewals projects highlights where shifts in these areas may require future adjustments.

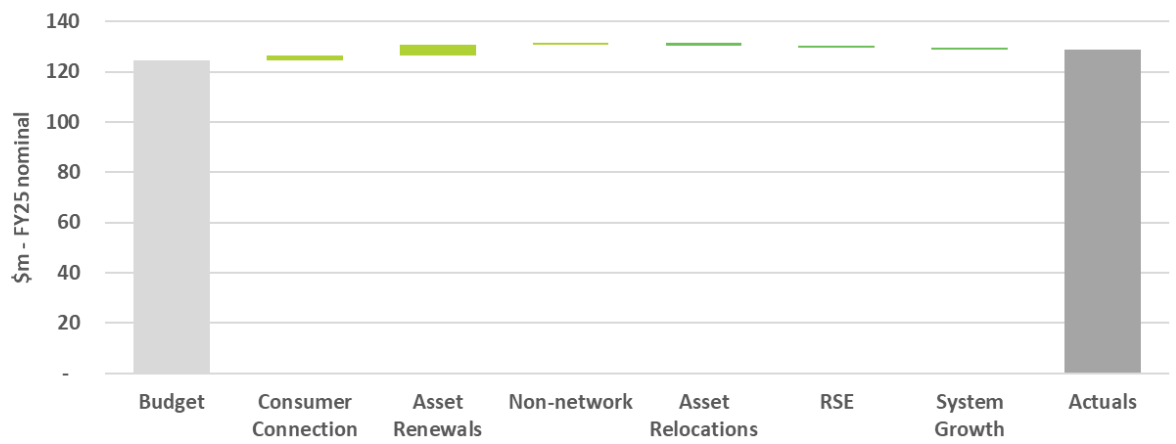
16.1 Performance against FY25 forecast

16.1.1 Capex

Comparing actuals from our FY25 Information Disclosure Schedule 7(ii) against the forecast in AMP 2025 (Schedule 11a), the variance shows an overall overspend of $4.3 million. FY25 finished broadly in line with forecast, with over- and under-spend across categories largely offsetting each other.

Overspend in consumer connections and some renewals was driven by higher customer activity and project-specific scope refinements. Overall, the result reflects active portfolio management and disciplined capital allocation. See Figure 16.1 for the comparison of capex performance against forecast.

Figure 16.1 FY25 capex performance against forecast[62]



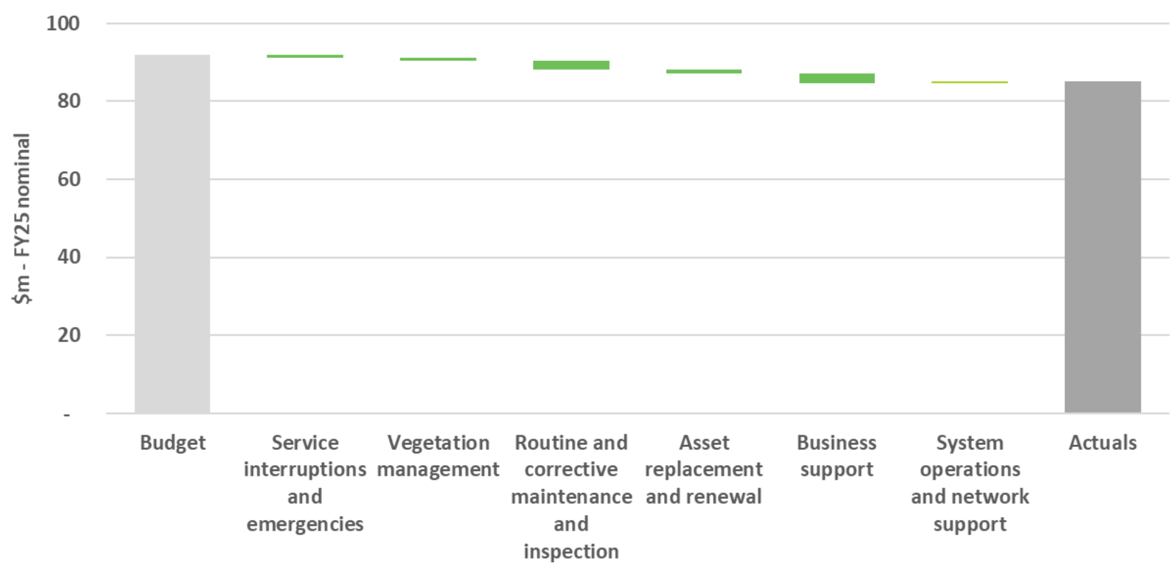
[62] Note: RSE is the reliability, safety, and environment portfolio.

16.1.2 Opex

Comparing actuals from our FY25 ID Schedule 7(ii) against the forecast in the 2025 AMP (Schedule 11b), opex came $6.9 million under forecast. Variances were primarily driven by the timing of maintenance activities and fluctuations in fault and emergency response volumes during the year.

There is also minor over- and under-spend across support categories reflecting the phasing of staff recruitment, training and development programmes, and timing impacts associated with the Integrated Asset Management system implementation, which experienced some delivery fluctuations. See Figure 16.2 for the comparison of opex performance against forecast.

Figure 16.2 Opex performance against forecast



16.1.3 System growth and asset renewals delivery vs forecast

For FY25, we delivered the majority of the large projects in the system growth and asset renewals area as planned, including carryovers, with the remaining work either in close-out or carrying over into FY26 due to unavoidable external delays.

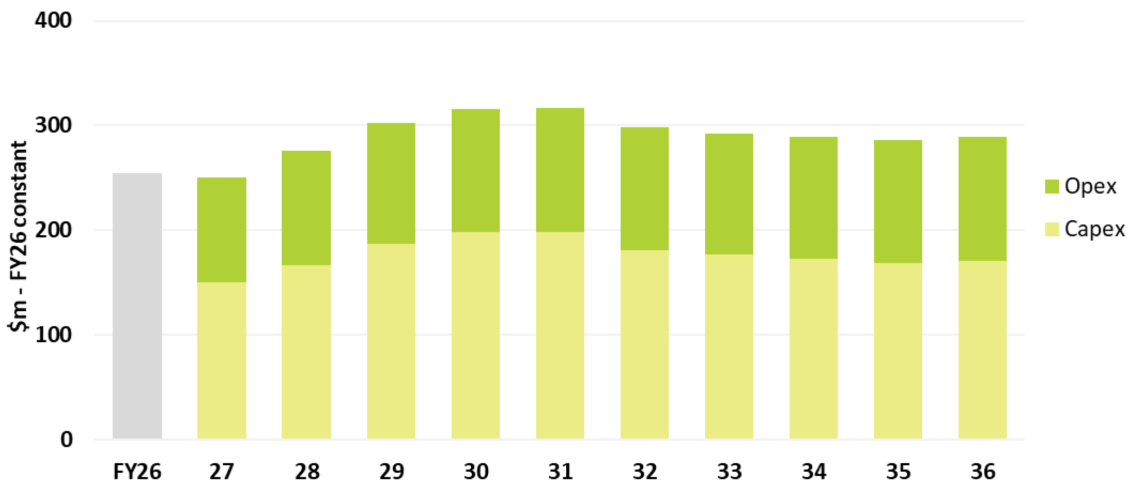
In the system growth area, the majority of projects were commissioned according to plan, with two projects delayed to FY26: procurement for the Burnham zone substation and design for the Halswell zone substation 66 kV upgrade. These timing shifts do not impact customer service levels as the projects were planned with sufficient lead time.

Assets renewals formed the core of our FY25 work programme, reflecting the need to replace ageing assets. We largely delivered what we set out to do. Work on the overhead and underground networks progressed well, with the majority of pole replacements and fuse replacements completed by year end. Several key substation renewals also reached completion, with only the final invoices and as-builts carrying into early FY26.

16.2 Total AMP investment overview

As described in Section 4 – Customers and stakeholders, we have incorporated what matters to customers and based on their priorities, we propose to invest $1.8 billion in capex and $1.1 billion in opex over the next 10-year AMP period. This represents an average annual total expenditure of $290 million.

Figure 16.3 Total AMP expenditure forecast per annum



Over the next ten years, our investment is projected to increase significantly, because the environment in which we operate in is changing. Our network is ageing with assets now approaching the end of their serviceable life. Central Waitaha Canterbury's growth is accelerating and resilience risks from earthquakes and severe weather are rising. At the same time, new technologies such as electric vehicles (EVs), solar and batteries will be changing how customers use and generate electricity and how our core systems need to modernise so we can manage our network efficiently. Together, these pressures require a step-up in investment to maintain the level of service customers expect.

Without that step-up, or if we maintained our historical investment profile, risks would increase and customers would feel the impact. Ageing assets would fail more often, increasing the occurrence of potential safety events and causing more outages and higher long-term costs. For example, the network contains 8 zone substation sites with aged oil-filled 11 kV switchgear that cannot be fitted with arc containment; the probability of failure is increasing, presenting an unacceptable safety risk for staff and service delivery partners working on site, and causing suburb wide outages for customers while switching and repair works are undertaken. Deferring this work further will create a growing backlog of major works, increasing both future cost and complexity. More broadly, growth would be constrained, resilience would not be improved and integrating new technologies would become harder.

Increasing investment now is how we maintain service quality, support a growing region, and prepare our network for future energy needs. Ultimately, we will be delivering better outcomes for customers in the long-term.

16.2.1 Capex overview

Our capex for the AMP period represents a prudent and efficient investment pathway that responds to the condition of our assets, a growing region, and the increasing importance of network resilience. The forecast reflects both the uplift required through the CPP period and a relatively stable level of investment over the remainder of the 10-year planning period. Without sustained capital investment across the various areas listed in Figure 16.4, we would be unable to respond to our five investment priorities, risking declining reliability, constrained growth, slower technology adoption, and reduced resilience.

As shown in Figure 16.4, during the CPP period (FY28-FY32), capex increases from approximately $166 million to $199 million per year. The smooth uplift in this period reflects sequenced work that addresses the most pressing needs while ensuring a manageable transition and delivery by our SDPs.

Beyond FY32, the forecast shows a more stabilised level of capex, averaging around $172 million per year. This is a managed transition to a sustainably paced business and asset lifecycle management. The expenditure breakdown is listed in Table 16.1.

Figure 16.4 Capex by Orion's internal expenditure categories

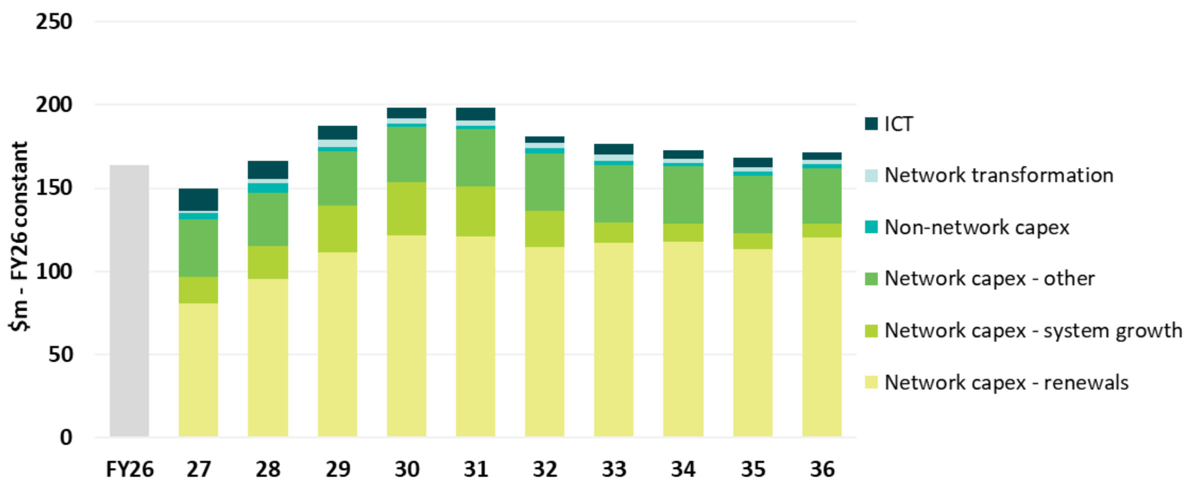


Table 16.1 Capex breakdown by Information Disclosure expenditure type ($m, FY26 constant)[63]

Category	Sub-Category	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Asset renewal capex	Asset replacement and renewal *(Section 14)*	80.4	95.5	111.6	121.6	120.8	114.7	116.9	117.7	113.1	120.4	**1,112.6**
System growth capex	System growth *(Sections 9, 12)*	16.6	20.6	30.8	33.4	31.6	22.7	14.4	12.0	10.6	8.9	**201.6**
Network capex - other	Quality of supply *(Section 12)*	1.1	1.8	1.9	1.9	2.0	2.2	2.1	1.7	1.6	1.5	**17.8**
	Legislative and regulatory *(Section 12)*	-	-	-	-	-	-	-	-	-	-	**-**
	Other reliability, safety and	4.1	1.0	1.1	1.2	1.3	1.2	1.2	1.2	1.2	1.2	**14.9**

[63] Categories reflect Commerce Commission Information Disclosure terminology (Schedule 11a). Where the AMP uses different terms — for example, 'Renewals' rather than 'Asset replacement and renewal'— these refer to the same underlying expenditure. Figures are rounded to one decimal place and may not sum exactly.

	environment *(Section 12)*											
	Consumer connections[64] (*Customer connections - Section 12*)	28.8	28.4	28.5	28.9	30.1	30.1	30.3	30.4	30.5	29.8	**295.8**
	Asset relocations (Section 12)[65]	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	**9.5**
Non-network capex	Other expenditure on non-network assets *(Sections 8, 9, 15)*	18.2	18.2	12.6	10.6	11.3	9.3	10.8	8.9	10.5	8.3	**118.7**
Total												**1770.9**

16.2.2 Opex overview

Our opex for the AMP period reflects what is required to operate, maintain, and support a growing and increasingly complex network. The profile shown in Figure 16.5 includes a lift in investment during the CPP period to a new steady, sustainable level beyond FY32.

Key contributors to the increase in cost during the CPP period include:

- responding to updated tree regulations and shifting to more risk-based vegetation cycles
- corrective, preventive, and reactive maintenance required to support an ageing asset base and higher utilisation across parts of our network
- systems operations and network support (SONS) and business support, covering data systems and operational visibility, and the capability needed to leverage the benefits these investments provide.

The forecast in Figure 16.5 shows opex increasing to an average of $114 million per year during and post the CPP period. The expenditure breakdown is listed in Table 16.2.

The increase in expenditure forecast reflects both the operational uplift required and the transitional activities needed to support delivery of the capex programme. Although capex reduces after the CPP period, opex remains elevated because the network will be larger and more complex, requiring ongoing operational and support activity. We have also built in expected efficiencies as new systems, processes, and ways of working are embedded. See Section 16.5 for more detail.

Delivering on our five investment priorities relies not only on what we build, but on the people, systems, tools, and operational activities funded through opex to run our network safely, respond to faults, manage resilience risks, and operate new technologies.

[64] Net of customer contribution.
[65] Ibid.

Figure 16.5 Opex by Orion's internal expenditure categories

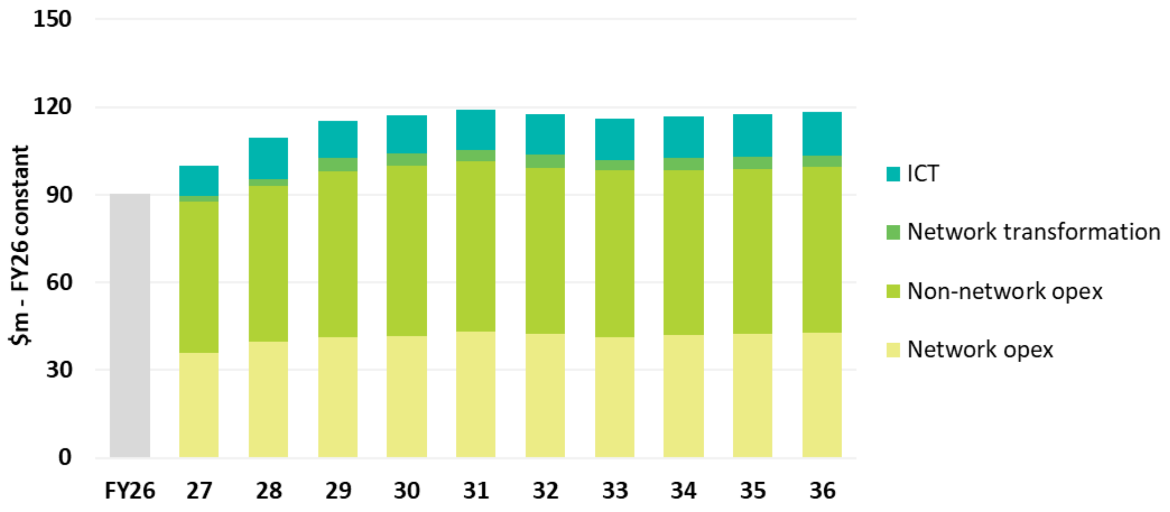


Table 16.2 Opex breakdown by Information Disclosure expenditure type ($m, FY26 constant) [66]

Category	Sub-Category	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	Total
Non-network opex	Business support *(Section 8)*	41.6	46.2	46.9	47.9	48.7	48.0	48.0	48.2	48.4	48.9	472.8
	System Operations and Network Support *(Section 8)*	22.4	23.6	26.7	26.8	26.9	26.4	26.2	26.1	26.0	26.2	257.3
	Non-network solutions provided by a related party or third party *(Section 9)*	-	-	0.4	0.9	0.2	0.9	0.2	0.4	0.6	0.3	3.9
Network opex	Service interruptions and emergencies *(Reactive maintenance - Section 13)*	12.6	12.8	13.0	13.2	13.3	13.5	13.7	13.9	14.1	14.3	134.4
	Routine and corrective maintenance and inspection *(Section 13)*	16.3	18.4	18.6	18.5	19.5	18.2	17.1	17.4	17.6	17.7	179.3
	Vegetation management *(Section 13)*	7.1	8.3	9.6	10.0	10.3	10.5	10.5	10.6	10.7	10.8	98.4
Total												**1,146.2**

[66] Categories reflect Commerce Commission Information Disclosure terminology (Schedule 11b). Where the AMP uses different terms — for example 'Corporate Support' rather than 'Business Support, these refer to the same underlying expenditure. Figures are rounded to one decimal place and may not sum exactly.

16.3 Cost escalation

Our expenditure forecasts are presented in real FY26 dollars (constant prices) throughout this AMP to provide a consistent basis for comparison, unless otherwise noted. To convert these figures to nominal dollars, as used in the Information Disclosure Schedules, we apply a cost escalation methodology that reflects projected inflation and other economic movements specific to electricity distribution work.

We engaged the Sapere Research Group to provide annual percentage forecasts for key cost inputs including materials (aluminium, copper, steel), labour, and other capital goods. These forecasts are then weighted to create escalation indices tailored to our specific expenditure categories.

For capex, we have defined six primary escalator classes (Labour, Cables, Conductor, Transformers, Switchgear, and Other), which are further weighted within 44 capex categories to reflect the unique cost composition of different asset types.

For opex, we applied a similar approach using four key indices (Labour Cost Index (LCI) – All Sectors, Producer Price Index (PPI) – Inputs, Maintenance Labour, and Vegetation Control) weighted across seven opex categories.

To ensure the integrity of this approach, weightings are estimated independently of the Sapere percentage forecasts to avoid potential bias.

16.4 Cost estimation

We use a range of cost estimation approaches depending on the type of work and the quality of data available. Most opex activities and some capex portfolios are costed using a base-step-trend (BST) approach.

In some cases, particularly for investments such as 11 kV and LV network reinforcement projects, alternative estimation methods to forecast the cost and quantity of projects are required. However, for volumetric renewals programmes and zone substation capital projects, we primarily rely on our volumetric and tailored estimation methods respectively.

In this section, we describe the various cost estimation approaches.

16.4.1 Base-step-trend

We used the BST approach to forecast expenditure for work categories where costs are generally stable and repeatable. The approach is widely recognised as industry best practice and is used by the Commerce Commission. BST provides a consistent and efficient estimation approach for routine programmes, such as maintenance and non-network opex.

This approach includes three components:

1. **Base**: represents a typical level of expenditure which is usually taken as the most recent year.
2. **Step**: once the base year is confirmed, we apply a step adjustment to reflect any structural changes that may shift the cost profile, e.g. changes in materials specifications or new compliance obligations that would increase or reduce the baseline cost. We also consider the Commission's factors supporting the need for step change.
3. **Trend**: is applied to reflect forecast movement over the planning period, e.g. increasing network scale leads to more maintenance.

16.4.2 Unit rates

We use a structured P (unit rate) x Q (quantity) methodology to forecast expenditure for most programmes and projects. This ensures costs are reflective of the unique environment and real delivery circumstances for each programme and project.

16.4.2.1 Volumetric estimates

Volumetric estimates are used for high-volume, repetitive work programmes where project scope is reasonably consistent and well defined, e.g. poles and crossarm renewals.

The key determinant of accurate cost estimates for volumetric programmes is the use of historical costs from equivalent work we have completed. Unit rates based on historical outturns effectively capture the impact of past risks and that the aggregate impact of these risks across portfolios is unlikely to vary over time. This feedback is used to derive average unit rates to be applied to future work volumes. These rates reflect typical delivery conditions and are updated to incorporate changes in labour and materials.

Even though individual assets or sites may vary, e.g. a pole replacement may cost more in an urban location than in a rural one, these differences tend to balance out across large volumes of work.

16.4.2.2 Tailored estimates

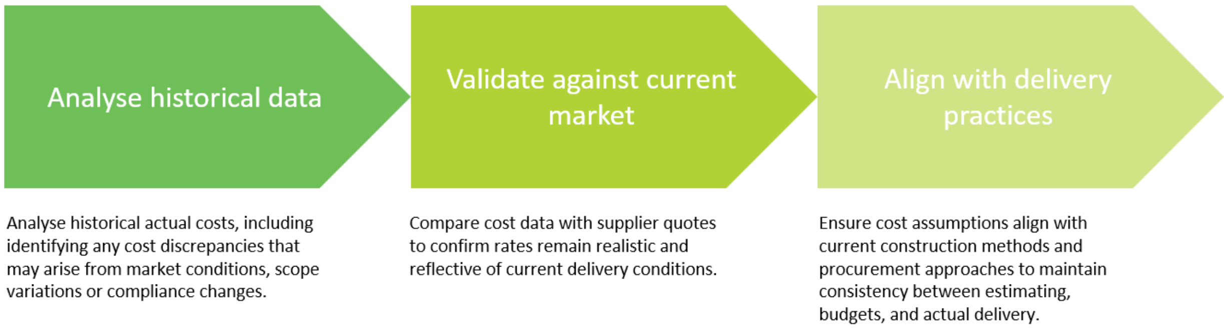
The tailored estimation approach is applied to complex, discrete projects, e.g. zone substation growth or renewal, where project scopes are defined. Project scopes are determined from desktop reviews of asset information, such as aerial photographs, site layout drawings, underground services drawings, and available cable ducts. These assessments provide reasonably accurate estimates for materials and work quantities, e.g. building extensions and cabling.

Based on these project scopes, we then build tailored estimates from 'building blocks'., which include standardised cost items, design allowance and overheads representing the typical scope, and inclusions for each work type. Building block costs are informed by historical costs (where available), service delivery partner rates, quotes, and external reviews. Material costs are determined with reference to supply contracts and historical costs.

16.4.2.3 Unit rates review process

All unit rates are maintained within a central Unit Rate Master Library which is managed by our Cost Engineering team. The library serves as a single source of truth for cost data and underpins the estimation templates used for business cases. Rates are updated through a structured review process as shown in Figure 16.6.

Figure 16.6 Unit cost review process



In FY26, our unit rates were independently reviewed to ensure the rates are reasonable and comparable to expected New Zealand industry averages.

16.4.2.4 Estimate classification

We align our cost estimation practices with AACE International's classification standards which define estimates across various classes, based on project accuracy. Currently, most of our zone substation renewals and growth projects are based on Class 4-5 estimates which are appropriate for providing indicative costs with accuracy ranges suitable for expenditure forecasting across the ten-year planning timeframe. As our projects progress through design and delivery, we develop Class 2-3 estimates to support detailed scoping, procurement and delivery-stage budgeting.

16.4.3 ICT bottom-up forecasting

We have developed a bottom-up forecast of efficient costs to meet the future capabilities required of ICT. Unlike base-step-trend, which extrapolates from historical aggregate expenditure, the bottom-up approach identifies the specific systems, services and capability initiatives required over the AMP period and builds the forecast from the estimated cost of each component.

Our forecasting approach integrates several key components to build a complete picture of future ICT expenditure. We begin with historical spend patterns and current contractual commitments, which provide a baseline reflecting operational requirements and committed financial obligations. We then layer in forward-looking requirements based on our ICT capability roadmap, including system upgrades and replacements, cyber security, infrastructure and cloud services, and digital enablement initiatives.

Cost estimates for individual initiatives are informed by external vendor pricing and proposals, existing contracts, and input from internal subject matter experts. Vendor information provides market-tested pricing, while internal expertise ensures that estimates appropriately reflect organisational requirements, technical constraints and implementation complexity. Where relevant, we distinguish between implementation costs and ongoing licence, hosting and support costs to ensure appropriate capex and opex treatment.

This approach recognises the discrete and fast-evolving nature of ICT investment and allows us to transparently identify key cost drivers. It also enables us to appropriately reflect software-as-a-service (SaaS) and subscription-based arrangements, including recent changes in accounting treatment, which would not be adequately captured using alternative approaches such as base-step-trend.

16.4.4 Non-network solutions

The market for non-network solutions continues to develop, so we do not currently have a set of historic unit rates to reference for future projects.

We have used two methods for establishing the forecast opex cost of non-network solutions:

1. **Neutral cost benefit analysis**: in our economic calculator we adjust the non-network solutions opex cost upwards until the cost benefit ratio equals the traditional capex solution. This sets a ceiling price for the procurement of non-network solutions.
2. **Equivalent capex and opex**: in this approach we set an annual ceiling price for the procurement of non-network solutions at 10% of the capex for traditional network solutions. From a customer line charge perspective, opex is set at 10% p.a. of the capex for the possible traditional network solution, which is approximately equivalent. This ensures that customers will not pay more for non-network solutions but may benefit if non-network solutions can be procured at a lower cost.

16.5 Efficiency

Maintaining and improving efficiency is a core consideration in how we plan, forecast, and deliver our investment programme. As the scale and complexity of our network increases, we are focused on ensuring that consumers continue to receive value for money, both through disciplined cost management today and through targeted investments that reduce the long-term cost of delivering services.

A key contributor to efficiency is our procurement and delivery approach. We seek to maintain competitive tension wherever possible by using open and contestable procurement processes for major works, equipment, and services. This includes competitive tendering for high-value construction, design, and supply contracts, and the use of multi-year arrangements where appropriate to support efficient pricing, resource planning, and innovation by our service delivery partners. At the same time, we balance competition with the need to maintain a sustainable and capable supplier market, recognising that a stable pipeline of work supports productivity and reduces delivery risk over time.

In parallel, we are making deliberate strategic investments that will help improve the efficiency with which we plan, deliver, and operate the network. In particular, our investment in ICT and digital capability is expected to deliver benefits across multiple parts of the business. These investments support better asset data quality, improved workflow automation, enhanced planning and scheduling, and stronger integration between planning, delivery, and operational systems. Over time, these capabilities are expected to reduce manual effort, avoid duplication, improve decision-making, and enable more efficient ways of working. While some of these investments increase expenditure in the short term, they are expected to avoid higher future costs and support productivity improvements as new systems and processes become embedded.

For non-network opex, including SONS and business support, we have explicitly incorporated an allowance of 0.5% per year for ongoing productivity improvement where it is reasonable to expect benefits from enabling investments, particularly in ICT; which equates to 2.5% over the CPP period or 5.1% over the 10-year AMP period. This recognises that, while many areas of network opex are driven by growth in activity and asset volumes, some support functions are well placed to realise efficiency gains over time through technology, process improvement, and scale. Consistent with regulatory precedent, these productivity assumptions are applied at an aggregate level and are intended to reflect achievable improvements rather than relying on speculative or unproven savings.

We will continue to actively monitor efficiency outcomes through our internal governance, benchmarking, and performance management processes. As better information becomes available, and as new systems mature, we will refine our forecasts and delivery approaches to ensure that efficiency gains are realised and shared with consumers over time. This approach supports a prudent balance between investing to meet future needs and maintaining affordability; and it underpins the robustness of the expenditure forecasts set out in this chapter.

16.6 Limitations and key assumptions

In this AMP, we recognise that several factors introduce uncertainty into our long-term forecasts. These uncertainties can lead to difference between the forecasts presented in this AMP and the actual outcomes observed in future years. The limitations and key assumptions set out below help explain the conditions under which the forecasts have been developed, and the areas where variability is most likely to occur.

16.6.1 Limitations

Limitations that may impact on our forecasts include:

- **Data completeness:** this AMP is based on the best information available during AMP drafting stage. We are continuing to improve our asset condition and inspection data, which will further enhance lifecycle modelling and risk assessment over time.
- **External dependencies**: growth related expenditure is influenced by factors outside of our control, e.g. developer decisions, housing policy, and large commercial and industrial investment. These factors can change quickly and may require adjustments to timing or scope through future AMPs or where appropriate, a regulatory mechanism.

16.6.2 Key assumptions

Key assumptions that may impact on our forecasts include:

- **Demand growth**: our system growth forecasts are based on forecast installation control points (ICPs) and electricity demand growth. This reflects our best current view of population growth, electrification trends, and development activity across Central Waitaha Canterbury. However, higher than expected electrification could bring forward the need for earlier network investment.
- **Regulatory settings**: we assume no material change in regulatory obligations beyond those already signalled. We further assume that emerging regulatory workstreams (such as connection process improvements and visibility requirements) are implemented progressively and with reasonable transition timeframes. Significant changes in regulatory settings or funding could influence the timing and scale of investment.
- **Global supply chain and geopolitical risk**: we recognise that geopolitical instability and regional conflicts may impact supply chains, particularly for critical electrical equipment and materials sourced from global markets. Our forecasts assume current lead times and availability remain broadly consistent with recent experience. We will continue to monitor global market conditions and adjust our procurement strategies, supplier arrangements, and contingency plans as needed to maintain programme delivery.
- **Cost escalation**: our expenditure forecasts are presented in real FY26 dollars (constant dollars) throughout this AMP to provide a consistent basis for comparison. To convert these to nominal dollars over the planning period, we apply a cost escalation methodology that reflects projected inflation and other economic movements specific to electricity distribution work.
- **Deliverability**: the forecasts assume that our internal resources and our service delivery partners are able to deliver the planned uplift in work. As with other infrastructure sectors in New Zealand and globally, labour market constraints and competing projects can influence the pace and sequencing of work. We actively manage these delivery risks through planning, contracting approaches, and workforce strategies. See Section 17 – How we deliver for further detail.
- **Energy transition**: we assume no material changes to regulatory obligations beyond those already signalled. For technology adoption, e.g. EV charging, distributed energy resource integration and batteries, we assume these will continue broadly in line with current projections. Significant shifts in regulatory settings, rapid change in technology behaviour, or a change in government priorities and funding could influence the timing and scale of investments. We also assume that changes emerging from regulators workstreams, e.g. connection process improvements and visibility requirements, occur progressively and with reasonable implementation timeframes
- **External dependencies**: our forecasts assume that the timing of housing developments, commercial projects, and third-party infrastructure upgrades broadly aligns with current information provided by councils and developers

- **Unit rates**: our forecasts assume that continued improvements in systems, tools, and delivery approaches will provide better visibility of real-world unit costs.
- **Data completeness**: we assume that ongoing improvements in asset data, including the rollout of Maximo, enhanced inspection processes, and stronger condition information, will continue to improve the quality of our asset intelligence.

To the extent that it is possible, these assumptions are quantified in scenario and options analysis in the models that underpin our expenditure forecasts.

16.7 Areas of investment uncertainty

Our expenditure forecasts reflect the best information available during AMP development, but like all long-term plans, they are shaped by a number of uncertainties due to the limitations and key assumptions described in the previous section. These uncertainties do not undermine the robustness of the forecasts, rather, they highlight where we expect to refine our plans as better data becomes available.

The earlier years of this AMP are based on more detailed analysis of demand forecasts, asset condition information and confirmed investment programmes, resulting in a higher level of certainty.

Forecasts for the later years of this AMP are progressively less certain, as they extend further into the future. These forecasts are suitable for indicative planning purposes and provide direction for our long-term asset management strategy. Through each annual planning cycle, we will update and refine these forecasts as new information becomes available, progressively transitioning them from strategic intent to deliverable programmes.

We only include the work we have a reasonable degree of confidence in, for our forecasts. Areas where timing or scale is less certain are monitored closely and will be incorporated into future AMPs when the need is clearer. This approach ensures our investments remain prudent and we avoid asking customers to pay more than necessary.

To help guide our decision-making, we assign each key assumption a level of uncertainty:

- **High**: influenced by factors largely outside of our control, e.g. policy settings and developer decisions. These factors may materially affect the timing or scale of investment.
- **Medium**: some uncertainty remains, but we can reasonably predict direction and scale.
- **Low**: high confidence based on reliable data.

We manage the various levels of uncertainty that exists in our forecasts by improving the quality of information we use, maintaining flexibility in our delivery programmes, and monitoring signals that may trigger a change in timing or scale of projects.

Table 16.3, on the following page, summarises our key assumptions and the steps we are taking to manage the uncertainty levels.

Table 16.3 Areas of investment uncertainty

Assumption	What the assumption covers	Uncertainty	How we manage this uncertainty
Demand growth	Moderate ICP and energy demand	High	The pace of electrification will influence when additional capacity is needed, and a higher rate of uptake or new industrial activity may bring forward reinforcement requirements. Even though we work closely with our major customers to understand their plans, some variability in timing and scope is inevitable. We rely on regulatory mechanisms, such as reopeners, to accommodate these uncertain projects. Further detail on contingent and nascent projects is provided in Section 12 – Network development programme.

Table 16.3 Areas of investment uncertainty

Assumption	What the assumption covers	Uncertainty	How we manage this uncertainty
Cost escalation	Material and labour inflation	Medium	We track labour and materials inflation through procurement activity, supplier feedback, and market indices. This allows us to continuously update unit rates, identify bundling opportunities, and maintain efficient delivery across renewals, growth and resilience portfolios.
Deliverability	Availability of internal workforce and service delivery partners to deliver planned volumes	Low	We will continue to work closely with our service delivery partners to understand workforce capacity and contractor availability, while supply chain lead times will allow us to sequence work more effectively across all investment categories.
Energy transition	No major changes beyond those already assumed in the forecast input. Assumes stable policy settings with no major shifts impacting demand or funding	Medium	We track uptake of EVs, solar, batteries, and flexible demand services, as well as emerging regulatory requirements. This helps us time investments in hosting capacity, visibility tools, and reinforcement so that we build ahead of need — but not excessively early.
External dependencies	Housing pipelines, commercial developments and third-party investment decisions	High	We maintain close engagement with councils and third parties to understand the timing of new subdivisions, commercial projects, and infrastructure upgrades. This helps us adjust sequencing of system growth and township reinforcement so that we invest where and when it is needed, rather than committing ahead of confirmed demand
Unit rates	No major changes (in addition to cost escalation indices above) to unit rates over the AMP period	Medium	As we continue to embed new systems and tools, better insights into real-world unit costs will help us to refine unit rates.
Data completeness	Improving but incomplete condition or performance data for asset portfolios	Medium	We are continuing to roll out Maximo, improve inspection processes, and strengthen condition data. As data quality improves, we will refine the timing and prioritisation of renewals and maintenance to ensure investment remains well-targeted

16.8 Investment prioritisation

Our 10-year plan continues to adapt as new investment drivers emerge. Before seeking any formal reopener or regulatory mechanisms, we first assess whether our existing investment plan can be reprioritised. This ensures we continue to challenge our plan internally, deferring or reshaping projects where the underlying investment need has shifted.

Reprioritisation is not straightforward. Each decision requires us to weigh customer impact, network risk, long-term value and affordability. Our customers have told us they value safety, reliability, resilience, and an equitable transition to a low-carbon future; but they also recognise that we cannot do everything at once. We apply a structured approach that reflects both customer expectations and our obligations, and reflects our strategic priorities as outlined in section 3.2. Reprioritisation priorities are ordered as described in Table 16.4.

Table 16.4 Investment prioritisation for capex projects and programmes

Priority	Category	Description
1	Customer-driven demand	As the sole electricity distributor in the region, we have an obligation to respond to customer requests for new or upgraded connections. These projects are often time-sensitive and driven by customer growth or development. They include both individual connections and upstream network reinforcements required to support that demand.
2	Safety	We have zero risk appetite for safety-related issues. Our Risk Guideline requires that we take all reasonably practicable steps (AFARP) to eliminate or mitigate risks to our staff, contractors, and the public. Safety is non-negotiable and will always take priority in our planning and delivery.
3	Risk reduction and compliance	Other risks such as those related to compliance, resilience, or environmental impact are prioritised based on our Risk Guideline. Where a risk has been assessed as exceeding our appetite, we aim to resolve it in a timely and proportionate manner. While some flexibility may exist in timing, our preference is to address known risks before they escalate. This includes proactive investments in ageing infrastructure, environmental mitigation, and resilience strengthening.
4	Performance service and optimisation	This includes investments that improve the quality of supply and customer experience. For example, targeted reliability improvements, enhanced communication around outages, or streamlined connection processes. Some of these investments are supported by cost-benefit analysis and can be deferred if necessary to prioritise more urgent customer or risk-based needs. However, they remain important for meeting evolving customer expectations.
5	Environmental sustainability	Our customers expect us to support the transition to a low-carbon energy future. While this is a growing area of importance, and aligns strongly with our long-term strategy, it currently sits lower in the prioritisation hierarchy. This reflects the need to balance sustainability initiatives with our core obligations around safety, reliability, resilience and affordability.

16.8.1 Making informed trade-offs

Balancing these priorities is a core part of our asset management practice. We do not always select the lowest short-term cost option. In some cases, we invest more upfront in solutions that deliver greater long-term value, reduce lifecycle costs, or build flexibility to respond to future needs.

There are also times when we accept conscious trade-offs between outcomes. For example, we may accept a temporary impact on reliability to resolve a higher-priority safety risk. These decisions are guided by our risk framework, economic analysis, and customer insights, to ensure we deliver the greatest net benefit over time.

Customer affordability shapes how far and how fast we can progress. Our Customer Advisory Panel, described in Section 04 – Consumers and stakeholders, helped us test different investment scenarios to help inform the balance between affordability and the pace of improvement across customer, community, and asset management objectives. We will continue to refine our prioritisation approach through ongoing consultation.

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17. How we deliver

This section describes how we will deliver our work programmes safely and efficiently. It outlines our delivery model, resourcing, partnerships, procurement approach, and the key factors influencing our ability to deliver.

17.1 How we deliver our work programmes

To ensure the work programmes in this AMP are realistic and achievable, we conducted a formal deliverability assessment covering field resources, internal capability, supply chain readiness, and design capacity. This assessment included:

- modelling our required field resources by work type and skill category against the planned work programme for the AMP and CPP periods
- engaging with each of our service delivery partners to assess their capacity to support the planned uplift in work volumes, and obtaining confirmation of their ability to deliver
- profiling our internal resource requirements and identifying additional roles needed
- assessing the availability of key materials and long-lead equipment
- reviewing design and specialist resource capacity across our engineering and design partners.

Our assessment confirmed that the work programmes outlined in this AMP can be delivered within the planned timeframes. Deliverability evidence for our CPP Application, including resource modelling and service delivery partner commitments, is provided in our CPP Main Proposal, Chapter 4 – Delivering our CPP plan.

17.1.1 Delivery model

Our delivery model combines internal capability with long-standing partnerships with our service delivery partners across the region. Our Network Portfolio and Procurement teams plan, design, programme, and award work to our service delivery partners, with assistance from other internal support functions where required.

Our Network Delivery team manages execution of work programmes in partnership with our service delivery partners. We also have a designated Customer Connections team who manage new and augmented connections.

Our delivery programme operates within the governance framework described in Section 6 – Asset management system. All network and non-network capex investment is subject to our delegated financial authority policy and investment decision framework, which ensures appropriate challenge and review at each stage from needs identification through to final approval. The Board approves the overall AMP and annual work programme, with individual project approvals delegated according to the scale and complexity of the work.

This governance structure ensures that our planned work programmes are not only deliverable, but also subject to the appropriate level of organisational oversight and approval.

17.1.2 Monitoring and reporting of programmes

To ensure the capex and opex programmes are delivered as planned, we maintain a structured approach to monitoring and reporting across all programmes and projects. We track delivery performance against approved plans across scope, cost and timing. These metrics are updated regularly and provide early visibility of variances across the portfolio.

Monthly programme reviews enable us to assess progress, reallocate resources where needed and take corrective actions. Delivery performance is reported regularly to the ILT and Board, providing governance visibility of progress against the work programme and supporting timely decision-making where variances arise.

Where changes in demand, delivery conditions or external factors occur, we update forecasts and if required, reprioritise our work programme in line with the investment prioritisation approach described in Section 16.8.

17.1.3 Planning and sequencing our work

We manage comprehensive work programmes, from customer connections to subtransmission cable installations, renewal of ageing assets, reinforcement works, and the day-to-day work to keep our network safe and reliable.

Weekly cross-functional check-ins allow us to adjust our work programmes when needed. This cadence is important as it helps us identify risks early, allocate work between service delivery partners and key design partners to balance workloads and keep the overall work programmes on track.

During the planning phase of the work programmes, a comprehensive assessment is undertaken to determine the specific consent requirements relevant to the project. Although Orion possesses a global earthworks consent, additional consents may be required for new buildings or land developments in accordance with local authority regulations. Consent applications are submitted once the design has reached an advanced stage and any due diligence has been performed, ensuring that all design criteria are met to a standard appropriate for submission and approval. Furthermore, these consents necessitate ongoing monitoring and reporting to verify continued compliance with their conditions throughout the lifecycle of the asset.

17.1.4 Building internal capability

To deliver the work uplift we expect over the AMP period, particularly the uplift over the CPP period, we are strengthening our internal capability both in SONS and Business Support. Over the next two years we are focused on lifting capability including building expertise in areas such as LV network management and planning, load forecasting, protection and control engineering and operational technology to support our network transformation. We are also focused on uplifting capabilities within the Business Support function to provide regulatory expertise, data management and strategic planning needs.

Over the past three financial years, we have consistently recruited at speed and scale, successfully increasing our capacity to deliver critical programmes. This demonstrates that our end-to-end recruitment approach, including our sourcing, selection, and hiring practices, has been thoroughly tested under demanding conditions and proven effective. Our employee value proposition also remains strong, reflected in a 95% average offer acceptance rate, which is higher than the New Zealand average and aligns with the performance of leading organisations.

Crucially, the level of recruitment we have already achieved aligns with what we have forecasted is needed for the AMP period. Our turnover has also remained low.

Together, these factors give us confidence in our ability to recruit the internal staff required to support the delivery of our work programmes.

The implementation of Maximo and our wider Integrated Asset Management (IAM) system further strengthen our ability to meet our required work programmes by reducing manual work, improving asset data quality, and enhancing coordination and transparency between planning, procurement, and delivery teams. These improvements will increase our ability to deliver an increased programme of work efficiently.

17.1.5 Working with our service delivery partners

Our service delivery partners, together with a range of specialist providers, such as designers, equipment suppliers, and vegetation contractors, remain at the core of our delivery model.

Our service delivery partners also have a strong track record of attracting and retaining the resources needed to deliver through periods of significant industry pressure. Their longstanding presence in New Zealand has enabled them to maintain stable workforces, including scaling workforce during the Canterbury earthquake recovery, and navigating the severe labour market constraints after the COVID-19 pandemic.

Several service delivery partners highlighted that they were able to retain capability, grow their teams, and scale rapidly during these events due to their established employment pathways, competitive employee value propositions, long-term contractual visibility, and the depth of their regional reputation. These same factors, along with access to domestic and international recruitment channels and structured apprenticeship and training pipelines, underpin their confidence in supporting the increased work programme associated with the CPP period.

17.2 Procurement and contract management

17.2.1 Our procurement approach

Our procurement is fair and transparent. Our procurement policies provide clear guardrails, and our teams follow established governance processes for procurement decisions. Our procurement principles are outlined in Table 17.1.

Table 17.1 Procurement principles

Principles	Key rationale
Competition Wherever Possible	We maintain a managed sustainable competitive market, where possible. Examples include: • Giving our customers a choice for new connections, whereby they can choose which of our service delivery partners they wish to engage for the design and construction of their connections • For large value procurement of supply, design, and construction contracts, such as zone substation design, construction and equipment procurement, we always tender the work to ensure value for money and competition.
Sustainable Workflow for Service Delivery Partners	We continually analyse the internal and external forces acting on the market to ensure our current and future requirements will be met on an ongoing basis. We need to balance this by ensuring that our key service delivery partners have a steady flow of work to keep them sustainable, competitive, and competent.
Sourcing	We use a combination of direct/closed and open procurement methodologies depending on the works value/risk and type to ensure value for money and that wider public value is achieved.
Contract Length to Facilitate Efficient Pricing and Resourcing	We award multi-year contracts to encourage efficient pricing, innovation, and service delivery partner/supplier confidence and sustainability.

Table 17.1 Procurement principles

Principles	Key rationale
Direct Procurement for High-Value Equipment	Larger value and complex equipment such as 66 kV cables, transformers, switchgear, and secondary systems, including protection relays, are procured directly by us. This helps us avoid management and handling fees that another party would incur and pass onto us, and to minimise ordering errors and risks that another party might introduce. It also helps us maximise the technical expertise of our in-house engineering teams and foster innovative and enduring relationships with our manufacturers.
Emergency Preparedness and HILP Response	We contract some of our service delivery partners to respond to emergencies on our network. We also ensure that we retain the right level of spares and stock to respond to major events, including HILP events. We learned first-hand from the Canterbury earthquakes that stock on hand is vital, as is the right level of resource and skillset. We are well prepared, and resiliency focussed for any future major event.
Contract Performance Management	Performance management is undertaken throughout the life of a contract and for all contracts, whether they are straightforward or complex. Along with performance indicators and standards, arrangements for monitoring and assessment are set out in each contract, along with actions that would result from underperformance. Our Contract Compliance Guide outlines the fundamental requirements for monitoring the performance of our service delivery partners in accordance with established contract standards. Contract performance management can take the form of, for example, key performance objectives/indicators, audits, compliance plans, and inspections of works. As a minimum, performance monitoring ensures that the goods or services are safely delivered in a compliant way, on time, at the agreed cost and to the required quality.
Specialist Service Delivery for Vegetation Management	We utilise specialised service delivery partners for maintenance works. Any project work is tendered to a panel, which includes additional vegetation management service delivery partners.

17.2.2 Managing factors affecting project delivery

Delivering a large and complex programme is never risk-free. There is a certain level of risk involved, whether it is labour constraints, supply chain variability, weather, or unexpected field conditions. We focus on understanding these risks early on in a programme and put in practical mitigations so that the residual risk is manageable.

To deliver the uplift in work volume during the AMP period efficiently and at the unit rates specified in our cost estimation processes we will need to create opportunities to improve work practices and customer outcomes. Increased scale allows us to bundle works and make targeted investments in enabling systems, tools, and standardised delivery approaches. These initiatives support effective resource utilisation across our service delivery partners and internal teams.

Based on our internal risk assessment, we believe the delivery risks, outlined in Table 17.2, are manageable. This confidence comes from the strength of our partnerships with our service delivery partners, the maturity of our procurement process, the uplift we are making in internal capability, our planning processes, and our track record of delivering through challenging conditions.

Although the risks listed below are real, they are not beyond what we and our service delivery partners have successfully managed before. Our delivery model has been tested through significant uplift periods, and our service delivery partners have responded to major surges in Orion-related work in recent years. For example, both the Canterbury earthquake recovery (2011–2017) and the Canterbury subdivision boom (2012–present) are where service delivery partners have increased resources to support sustained growth in local development. Our experience, combined with our deliverability assessment for CPP, gives us confidence that our delivery risks are manageable and we are well positioned to deliver our work programmes outlined in this AMP.

Table 17.2 Delivery risks and mitigation strategies

Risk area	Risk description	Mitigations
Recruitment for internal staff	Inability to recruit the required resource due to a lack of available qualified candidates in the market, resulting in delays or additional costs due to consultancy spend.	We have matured our outsourced recruitment partnership model, refined our sourcing strategy, and strengthened workforce planning to ensure agility and scalability. In addition, we have deployed talent pooling functionality to maintain engagement with individuals who express interest in joining Orion, enabling us to source from an inactive pool and leverage our broader talent networks. We have also developed early careers pipelines for trades, engineers to attract diverse talent and build a sustainable workforce for the future.
Internal capability shift	Our employees may not have the skills required for the future of our network.	We have implemented a Learning Management System to capture skill sets and deliver learning. Our learning system is underpinned by our Core Behaviours competency framework, success profiles, career pathways, and future skills matrix. Together these elements drive learning and the development of future skills. Additionally, our graduate and technical trainee development programmes support the building of technical capability.
Retention and turnover	We may not have the ability to retain staff with the skill sets needed for the future	We have developed robust performance and engagement processes, along with a strong employee value proposition that has kept turnover low. To prepare us for the future, individuals with critical skill sets are identified and individual retention plans deployed
Supply chain for equipment	Potential shortages of key assets, such as poles, transformers, cable up to 66 kV, protection relays and switchgear, due to supply chain disruptions, e.g. global instability.	Regular market assessment to identify alternative sources of supply, improve efficiency, and achieve strategic supply chain objectives. Long-lead time items have forward planning for stockholding and long-term supply agreements are in place. We are working to increase minimum stock levels for critical items to at least 6 months, and we are enhancing our forecasting and planning to further improve forward planning and stock-level estimation.
Retention of external specialist designers	External designers may face challenges due to the loss of specialist designers or increased demand both nationally and internationally, which could impact on their availability.	We have recently grown our external design resources to spread this risk. We have a number of engineering and design partners we can call upon.
Delivery systems	Inefficient tools currently used for asset management and works delivery result in multiple manual touchpoints within the works delivery pipeline.	The completion of the Integrated Asset Management (IAM) programme phase one ecosystem of software products and processes is due for completion by FY28. This includes implementing Maximo for asset data and works management, and ESRI as the new GIS platform. Together, these systems will reduce manual handling, improve data quality and visibility, streamline workflows, and support more efficient planning, scheduling and delivery of work.
Unforeseen cost increases	Budget allocation shortfall due to unexpected costs and increases, including equipment and labour supply/demand costs, or unfavourable foreign exchange variations.	Connetics uses hedging for large purchases, such as cables, to stabilise costs and bulk buying to secure better rates. We set unit rates based on average costs, factoring in risk and cost variations through scale, and adjust them based on actual outcomes. For major overseas purchases of equipment, we also hedge foreign exchange (if applicable) and develop contracts that may include metrics linked to metal exchange, labour and PPI indexes.


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18. Asset management improvement

Meeting our asset management objectives requires a step-up in network investment. We know that efficiently delivering our proposed investment programme requires enhancement of our asset management capabilities to further develop our planning, decision-making, delivery coordination, and performance monitoring capabilities, to ensure we can prioritise effectively across competing needs and demonstrate value for customers.

This section outlines our current asset management maturity and establishes an asset management improvement roadmap to ensure long-term operational excellence.

18.1 Current maturity assessment summary

We periodically assess our asset management maturity using the Asset Management Maturity Assessment Tool (AMMAT), to evaluate our practices against industry good practice standards. The AMMAT consists of 31 questions across six assessment areas, with scores ranging from 0 (innocent) to 4 (excellent).

While the AMMAT is designed as a self-assessment tool, we engaged Edison Consulting Group to undertake our AMMAT assessment alongside a comprehensive gap analysis against ISO 55001:2024, the international standard for asset management systems.

Our AMMAT assessment resulted in an overall average score of 2.51 (Developing-Competent level). The context of this result is explained in section 18.1.2.

18.1.1 Recent improvements to our asset management system

We have continued to progressively improve our asset management capabilities over the past year, to ensure we continue to deliver a safe, reliable, and resilient electricity service at the lowest total lifecycle cost. As our network ages and customer expectations evolve, we have strengthened our analytical tools, planning processes and governance frameworks to support better-informed investment decisions. Over the past year, we have strengthened the processes that sit behind our expenditure forecasts through a combination of internal capability building and external scrutiny. The independent verification process as part of our CPP application preparation provided valuable external challenge, including review of whether our major programmes and project proposals are supported by good information and asset management decision-making processes, and whether we can realistically deliver the uplift in activity.

Key improvements completed to date include:

Strategic frameworks and governance

- Developed and implemented our first Strategic Asset Management Plan (SAMP), improving line of sight between business objectives and asset management activities.
- Developed an Asset Management Improvement Plan (AMIP), providing a structured approach to capability development (detailed in Section 18.2).
- Enhanced our Investment Decision Framework by strengthening reporting requirements to ensure consistent application across all capital investment types.
- Developed Procurement Principles that establish a consistent framework for how we engage the market, manage contracts, and sustain the capability of our service delivery partners across the full range of network procurement activity.

Organisational improvements

- Restructured our internal teams in late 2024 to establish clear accountability for works planning, procurement, and delivery, with dedicated network portfolio, procurement, and delivery teams providing line-of-sight from planning through to field execution.
- Established a new Asset Management team structure in April 2025, creating dedicated roles and clear accountabilities for asset strategy, planning, investment decision-making, and continuous improvement.
- Implemented a Learning Management System to capture skill sets and deliver learning, underpinned by our Core Behaviours competency framework, success profiles, career pathways, and future skills matrix, supporting the development of technical capability required for our investment programme.

Asset management practices

- Replaced our Asset Management Reports with comprehensive Asset Class Strategies, documenting our approach to managing our network asset classes and associated asset fleets.
- Improved our business case template to better align to The Treasury New Zealand's Better Business Case framework.
- Developed a good electricity industry practice economic calculator to support consistent cost-benefit analysis.
- Strengthened supply chain planning by establishing long-term supply agreements for critical long-lead time equipment, increasing minimum stock levels for key items, and enhancing forecasting and planning to improve stock-level estimation and resilience to global supply chain disruption.

Analytical and forecasting capabilities

- Improved analytical techniques and modelling, including adoption of replacement expenditure models and survivorship modelling.
- Enhanced demand forecasting modelling and approaches, including weather correction and probability of exceedance (PoE) modelling, leveraging advice from an external consultant, Frontier Economics.

Expenditure modelling

- Consolidated a single 'source-of-truth' for historical expenditure data to support robust forecast modelling, and incorporated learnings from external reviews of unit rates, renewals modelling, and network development planning.
- Refined our costing methodology by introducing new cost building blocks.
- Adopted base-step-trend methodology for opex modelling.

These improvements underpin the investment plans presented in this AMP and represent our commitment to continuous improvement in asset management practice.

18.1.2 Understanding our FY26 assessment results

The FY26 assessment was conducted during a period of significant organisational transformation. We were simultaneously implementing new core information systems through our Integrated Asset Management (IAM) programme, implementing the key asset management improvements identified in Section 18.1, and embedding a new organisational structure implemented in April 2025.

Our FY26 AMMAT score reflects both genuine capability gaps we are actively addressing through our AMIP, and our on-going transformation to new asset management information systems and processes while they are being established and integrated into the business. This "re-baselining" will enable us to transition to a much greater level of asset management maturity in the medium term.

Two factors shape the FY26 assessment:

- **Scoring methodology**: the AMMAT distinguishes clearly between established frameworks (which may score 2.0) versus frameworks which are embedded and demonstrate sustained operational effectiveness (which score 3.0+). Having a process documented and approved is different from that process being consistently embedded in business-as-usual operations and delivering its intended outcomes.
- **Transformation timing**: many results reflect transitional status where frameworks are established and improvements are underway, but operational validation through sustained business cycles remains pending. These changes require time to demonstrate effectiveness through normal business operations before scoring at higher maturity levels.

18.1.3 FY26 assessment results

Many individual question scores decreased from the 3.5-4.0 range to 2.0-2.5, reflecting conservative scoring during the transformation period. As our IAM programme completes, our new organisational structure embeds, and improved processes demonstrate effectiveness through sustained business operations, we expect scores to progress toward 3.0-3.5 within 12-18 months.

Our current maturity level has specific implications for our ability to deliver on our asset management objectives outlined in Section 6 – Asset management system. Table 18.1 summarises how our AMMAT performance affects each objective and how our AMIP addresses identified capability gaps.

Table 18.1 AMMAT performance evaluation against asset management objectives

AM objective	Assessment areas	Current maturity	AMIP response
Safety	Risk management, asset health application, lifecycle decision-making	Inconsistent application of asset health indices and risk-based approaches limits optimisation of safety interventions and proactive hazard management.	Asset health and criticality application, risk-based decision framework, and enhanced inspection programmes.
Reliable Network	Asset health application, performance monitoring, lifecycle activities	Inconsistent use of asset condition data in renewal timing decisions affects ability to optimise lifecycle investments and maintain reliability performance.	Asset health and criticality application, AMS performance monitoring, and enhanced inspection programmes to improve asset health data quality.
Resilient Network	Contingency planning, risk management, emergency response	Strong contingency planning foundations, but systematic integration of resilience considerations into lifecycle decisions requires enhancement.	Risk-based decision framework, enhanced inspection programmes for structural resilience, and integration with Resilience Strategy development.
Operational Excellence	Information management, lifecycle activities, performance monitoring, audit, continual improvement	Current transformation of systems, processes, and data-driven decision-making capabilities provides foundation for enhanced optimisation of asset performance, cost, and risk.	Process mapping, AMS performance monitoring, internal audit programme development, and systematic integration across all AMIP phases.
Powering Today, Enabling Tomorrow	Technology and innovation	Strong capability in seeking and acquiring knowledge about new technology and practices.	See Section 9 – Transforming our network for further details on our network transformation improvement initiatives.
Customers and Community	Communication, participation and consultation	Opportunities exist to enhance systematic two-way	Asset management awareness initiatives and development of forward

Table 18.1 AMMAT performance evaluation against asset management objectives			
AM objective	**Assessment areas**	**Current maturity**	**AMIP response**
		communication with stakeholders and service delivery partners.	works visibility for service delivery partners.
Environmental Sustainability	Continual improvement, lifecycle management	AMMAT assessment has limited focus on environmental-specific capabilities. Our approach to lifecycle management and continual improvement provides the foundation for sustainable investment decisions.	

The detailed question-by-question AMMAT assessment, including evidence and scoring rationale for each of the 31 questions, is provided in *Appendix B.7 – Schedule 13 – Report on asset management maturity*.

18.1.4 ISO 55001 alignment assessment results

At the same time as our AMMAT assessment, Edison Consulting Group undertook a comprehensive gap analysis against ISO 55001:2024. The assessment evaluated our AMS against all seven sections of the standard. The overall picture reflects an organisation with strong operational and leadership foundations, where the primary development need is to move from documented intent to demonstrated embedded practice through process mapping, AMS-specific performance monitoring, and systematic documentation of the management system itself. Key gap themes are summarised in Table 18.2.

Table 18.2 ISO 55001 key gap themes		
Gap theme	**Current state**	**AMIP response**
Asset management system (AMS) performance monitoring and review	Current AMS measures focus on operational outcomes, e.g. reliability, safety, and cost.	Develop AMS performance indicators, evaluating system effectiveness and health. Formalise management review processes.
Process visibility and systematic application	End-to-end process mapping is incomplete; limited visibility of corrective/preventive actions and asset management workflows.	Complete process mapping for key AMS processes as part of the IAM programme. Enhance systematic application and integration with continual improvement.
Asset health and criticality application	Inconsistent application of EEA Asset Health and Criticality Guides across asset classes.	Consistent application of industry-recognised asset health and criticality methodologies; systematic use of asset condition data to drive quantitative lifecycle decisions.
Data and information management	Core systems are operational but data requirements, quality standards, and integration specifications are not formally defined. No integrated data management plan exists.	Define AMS data and information requirements; establish data specifications and quality standards. Develop an integrated plan for data collection, quality improvement, and sharing across core platforms, including both financial and non-financial.
Internal audit programme	Business audit programme provides general assurance.	Develop systematic AMS audit programme focused on system performance and ISO 55001 conformance.

18.2 Asset Management Improvement Plan

Considering the identified continuous improvement opportunities above, we have developed our AMIP to provide a structured approach to developing our asset management capability. This plan is key to delivering our proposed CPP and AMP investment programme. Enhanced capabilities in process visibility, asset health application, and systematic performance monitoring will strengthen our ability to deliver on our asset management objectives

Improved capability will enhance our ability to prioritise investments effectively, manage costs, and deliver our programmes on time and on budget. Our AMIP establishes a systematic approach to building operational excellence through enhanced systems, processes, people, data, and planning.

The AMIP follows a three-phase implementation approach, as set out in Table 18.3 that follows our overall strategy phasing. This approach recognises that effective asset management maturity development is incremental and that foundational capabilities must be established before advanced improvements can be sustained. The initiatives described in each phase reflect our current understanding of priorities; as our asset management practices evolve and we gain further insight through delivery, specific initiatives and their timing may be refined accordingly.

Table 18.3 AMIP phases and key initiatives

Phase	Focus	Key initiatives	Timing	Supports asset management objectives
Match Fit	Establish AMS foundations and culture	ISO 55001:2024 alignment: update terminology in asset management documents to reference ISO 55001:2024; provide standard copies to staff and service delivery partners; develop reference guide for key requirements. Asset management awareness: develop asset management improvement journey communications; distribute messaging through organisational channels; extend awareness to service delivery partners. Define AMS scope: document AMS boundaries and applicability; align with the Asset Management Policy and SAMP; obtain formal governance approval. Knowledge and competence framework: define AMS-specific competencies beyond technical skills; develop knowledge-sharing programmes. AMS performance monitoring: develop AMS-specific KPIs for system effectiveness and health and continuous improvement; establish baseline measurements; integrate with Board/ILT reporting. AMIP: formally designate our AMIP as our AMS continual improvement framework; establish corrective action tracking for AMS nonconformities; define structured review inputs and outputs for AM Excellence Steering Committee.	FY27	Operational excellence
Embed and Deliver	Develop systematic processes and frameworks	Process mapping programme: map key AMS processes (risk management, lifecycle management, audit, management review, continual improvement, change control); establish process visibility and systematic application. Internal audit programme: develop AMS audit programme; define audit scope, frequency, and reporting. Strategic alignment: develop Resilience, Reliability and Community Energy Services strategies aligned to our	FY27 – FY29	Operational Excellence Safety Reliable Network Resilient Network

Table 18.3 AMIP phases and key initiatives

Phase	Focus	Key initiatives	Timing	Supports asset management objectives
		business and asset management objectives and customer preferences. Asset health and criticality application: implement consistent application of EEA Asset Health and Criticality Guides across all asset classes; integrate asset condition data into systematic lifecycle decision-making. Risk-based decision framework: improve risk-based prioritisation and integrate into project/programme decision-making. Investment Prioritisation Framework: develop a formal framework to provide a structured and transparent basis for assessing trade-offs and aligning investment decisions with customer outcomes. Operational capability: to support our risk-based decision making and application of our asset health and criticality improvement, we will make improvements to our inspection standards (see section 18.2.2.) AMMAT/Resilience Management Maturity Assessment Tool reassessments: annual maturity reassessments to track progress and identify emerging priorities.		
Leverage	Embed improvements and demonstrate sustained effectiveness through Operational Excellence	Systematic integration: AMS processes embedded in asset management system software (Maximo) with integrated workflows across asset lifecycle. Multi-year programme management: consistent multi-year forward works programme with coordinated delivery. ISO 55001 certification readiness: pre-certification audit conducted; system maturity demonstrated through business cycles. Continuous improvement culture: improvement opportunities systematically identified, prioritised, and tracked; effectiveness evaluation embedded.	FY30+	All objectives

18.2.1 AMIP outcomes

While our current asset management capabilities are strong, these systematic improvements will enhance them further as we deliver our investment programme. Consistent application of asset health and criticality methodologies, combined with risk-based decision-making, will help ensure we deliver the right investments in our assets at the right time as we look to ramp up our network investment. Enhanced decision frameworks, cost estimation, and prioritisation will further improve efficient work identification and delivery, managing whole-of-life costs.

Systematic forward works planning, multi-year programme management, and improved contractor coordination enable the greater scale of our operations to be delivered consistently against plan. Enhanced process visibility, integrated workflows, and strengthened accountability frameworks will also support delivery of our investment programme at scale. Our delivery model and service delivery partner relationships provide the operational foundation for programme delivery, while these AMIP improvements enhance coordination, transparency, and efficiency across the plan-procure-deliver lifecycle.

Our asset management system provides a solid foundation for managing our network assets over their full lifecycle. Ongoing development of performance monitoring, internal audit programmes, process mapping, and management review will progressively strengthen alignment with ISO55001 and improve our operational excellence capabilities. These continuous improvements build organisational resilience to adapt to evolving network challenges, while enhancing stakeholder confidence through increasingly transparent and defensible decision-making across all asset management activities.

18.2.2 Operational capability improvements

While our AMIP focuses on asset management system improvements, we are also enhancing operational capabilities through expanded inspection and condition assessment programmes. These improvements directly support our asset management objectives by improving asset health data quality and completeness, enabling earlier identification of defects and emerging risks, supporting more accurate lifecycle decision-making, and ensuring compliance with building and safety standards.

Key operational capability improvements include:

- **Overhead structures**: resuming our full pole inspection programme to address current backlogs, implementing enhanced inspection standards, and inspecting telecommunications poles transferred to Orion. We are also introducing earth potential rise testing for steel towers to monitor public safety risks.
- **Overhead conductors**: implementing conductor destructive testing to refine remaining life assumptions and undertaking targeted verification surveys to improve our conductor data accuracy.
- **Zone substations and distribution switchgear**: introducing cyclical New Building Standard (NBS) assessments to monitor seismic risk, implementing routine power transformer bund leak inspections, and conducting fire risk assessments for distribution kiosks to enable targeted remediation.
- **Secondary systems**: undertaking targeted condition assessments of signalling and communications cables and expanding routine SCADA and intelligent electronic device testing to improve reliability.

These expanded inspection regimes provide the asset health data foundation required for the risk-based decision-making and lifecycle optimisation capabilities established through our AMIP.

Together, these strategic system improvements and operational capability enhancements strengthen our ability to deliver on our asset management objectives efficiently and effectively.

Appendices

Appendix A – AMP glossary

A: Ampere; unit of electrical current flow, or rate of flow of electrons.

ABI: Air Break Isolator; a pole mounted isolation switch. Usually manually operated.

AC: Alternating current; a flow of electricity which reaches maximum in one direction, decreases to zero, then reverses itself and reaches maximum in the opposite direction. The cycle is repeated continuously.

ADMS: Advanced Distribution Management System; a software package to control and optimise the operation of an electrical distribution network.

Alpine Fault: a geological fault, specifically a right-lateral strike-slip fault that runs almost the entire length of New Zealand's South Island. It has an average interval for a major earthquake at every 290 years, plus or minus 23 years. The last major Alpine Fault earthquake occurred in 1717. The longest known major Alpine Fault earthquake return rate is believed to be around 350 years and the shortest around 160 years.

AMIP: Asset Management Improvement Plan; Orion's structured programme to address identified asset management capability gaps.

AMMAT: Asset Management Maturity Assessment Tool; a Commerce Commission-prescribed self-assessment tool used by EDBs to evaluate asset management practices, scored 0–4.

AMS: Asset Management System; the integrated set of policies, processes, people, and systems through which Orion plans, delivers, and improves its asset management activities.

AMP: Asset Management Plan.

AMP period: 10-year period from 1 April 2027 to 31 March 2036.

Biofuel / Biomass: Biofuels are any fuel produced from biological matter or 'biomass'. This can include agricultural and forestry crops and residues, organic by-products, and waste such as used cooking oil. Biofuels can help reduce emissions and contribute towards meeting Aotearoa New Zealand's climate targets.

Biodiesel: a renewable, biodegradable fuel manufactured from vegetable oils, animal fats, or recycled restaurant grease.

Bushing: an electrical component that insulates a high voltage conductor passing through a metal enclosure.

Capacitance: the ability of a body to store an electrical charge.

Capacity utilisation: a ratio which measures the utilisation of transformers in the network. Calculated as the maximum demand experienced on an electricity network in a year, divided by the transformer capacity on that network.

CB: Circuit breaker; a device which detects excessive power demands in a circuit and cuts off power when they occur. Nearly all of these excessive demands are caused by a fault on the network. In the urban network, where most of these CBs are, they do not attempt a reclose after a fault as line circuit breakers may do on the rural overhead network.

CCC: Christchurch City Council; the local government authority for Christchurch in New Zealand.

Continuous rating: the constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely effecting it characteristics.

Conductor: the 'wire' that carries the electricity and includes overhead lines which can be covered (insulated) or bare (not insulated) and underground cables which are insulated.

CPP: Customised Price-Quality Path Determination set by the Commerce Commission for Orion.

CPP Application: Orion's application to the Commerce Commission for a customised path, submitted alongside this AMP.

CPP period: five-year period from 1 April 2027 to 31 March 2032.
CRM: a customer relationship management system or software that helps track information and interactions between a company and its customers, with the goal of improving relationships and outcomes. Current: the movement of electricity through a conductor, measured in amperes (A).
Customer Demand Management: shaping the overall customer load profile to obtain maximum mutual benefit to the customer and the network operator.
DC: Direct current.
DER: Distributed energy resources; the capacity for customers to generate and store their own energy from sources including solar and wind will see electricity fed into grids locally, from households and businesses.
DERMS: Distributed Energy Resources Management System; a software platform used to manage a group of distributed energy resources.
DIN: Deutsches Institut für Normung; the German Institute for Standardisation. Equipment manufactured to these standards is often called 'DIN Equipment'.
Distribution substation: is either a building, a kiosk, an outdoor substation or pole substation taking its supply at 11 kV and distributing at 400 V.
DPP: Default Price-Quality Path FY26-FY30; applies to electricity lines businesses that are subject to price-quality regulation and is set by the Commerce Commission. It sets the maximum allowable revenue that the businesses can collect. It also sets standards for the quality of services that each business must meet.
EDB: Electricity Distribution Business; a company that owns and operates an electricity distribution network.
EV: Electric Vehicles; a vehicle that uses electricity for propulsion.
Fault current: the current from the connected power system that flows in a short circuit caused by a fault.
Feeder: a physical grouping of conductors that originate from a zone substation circuit breaker.
Flashover: a disruptive discharge around or over the surface of an insulator.
Flexibility services: are a range of existing and developing solutions that electricity system users can provide to help balance demand and supply in the electricity network and support its efficient use. Flexible technologies such as electric vehicles and solar can provide 'flexibility services' to electricity networks. By releasing power back to the grid at times of high demand, and storing it during times of lower demand, local 'flexibility services' unlock additional capacity and avoid network over-build.
Frequency: on alternating current circuits, the designated number of times per second that polarity alternates from positive to negative and back again, expressed in Hertz (Hz)
Fuse: a device that will heat up, melt and electrically open the circuit after a period of prolonged abnormally high current flow. Gradient, voltage: the voltage drop, or electrical difference, between two given points.
Future Energy Scenarios: Orion's published scenarios modelling plausible energy futures for Central Waitaha Canterbury, used to inform investment planning under uncertainty.
FY: Orion's financial year, from 1 April to 31 March.
GXP: Grid exit point; 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.

HILP: High-Impact-Low-Probability; an event that is not likely to occur but will have significant consequence to an organisation.
HV: High voltage; voltage exceeding 1,000 volts (1 kV), in Orion's case generally 11 kV, 33 kV, or 66 kV.
IAM: integrated asset management, Orion's programme of work to implement new integrated asset management information systems.
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 f lowing 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: the ISO 55000 series; a suite of international standards for asset management published by the International Organization for Standardization. The series comprises ISO 55000 (overview and principles), ISO 55001 (requirements), and ISO 55002 (guidelines for the application of ISO 55001.
Independent Verifier (IV): an independent expert engaged as part of the CPP application process to assess whether Orion's proposed expenditure is prudent and efficient.
kV: Kilovolts; 1,000 volts.
kW: Kilowatt; a unit of electric power, equal to 1000 watts.
kWh: Kilowatt hour; a unit of energy equal to one kilowatt of power sustained for one hour.
kVA: Kilovolt-ampere; an output rating which designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.
LiDAR: Light Detection and Ranging; remote sensing technology using laser pulses to measure distances, used by Orion for vegetation clearance assessment and network inspection.
LCB: Line circuit breaker; a circuit breaker mounted on an overhead line pole which quickly cuts off power after a fault so no permanent damage is caused to any equipment. It switches power back on after a few seconds and, if the cause of the fault has gone, (e.g. a branch has blown off a line) then the power will stay on. If the offending item still exists then power will be cut again. This can happen up to three times before power will stay off until the fault is repaired. Sometimes an LCB is known as a 'recloser'.
Legacy assets: assets installed to meet appropriate standards of the time, but are not compliant with current day safety standards.
Lifelines groups: local collaborations between lifeline utilities. They aim to reduce infrastructure outages, especially if HILP events occur. It was this collaboration that lead us to invest to strengthen our key substations before the Canterbury earthquakes.
LV: Low voltage; a voltage not exceeding 1,000 volts, generally 230 or 400 volts.
Maximum demand: the maximum demand for electricity, at any one time, during the course of a year.
MVA: Mega volt-ampere; a unit of apparent electrical power equal to one million volt-amperes, commonly used to express the capacity of transformers and substations.
MW: Megawatt; a unit of electric power, equal to 1000 kilowatts.
MWh: Megawatt hour; a unit of energy equal to one Megawatt of power sustained for one hour.

N: a network is said to have 'N' security or capability if the network cannot deliver electricity after the failure of 'one' overhead line, cable, or transformer.
N-1: a network is said to have 'N-1' security or capability if the network continues to deliver electricity after the failure of one overhead line, cable, or transformer.
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.
Non-network solutions: alternatives to traditional network infrastructure investment, including demand-side management, flexibility services, distributed generation, and battery storage, that can defer or avoid the need for network capital expenditure.
Ohm: a measure of the opposition to electrical flow, measured in ohms.
Outage: an interruption to electricity supply. Power cut.
PCB: Polychlorinated biphenyls (PCBs) were used as dielectric fluids in transformers and capacitors, coolants, lubricants, stabilising additives in flexible PVC coatings of electrical wiring and electronic components. PCB production was banned in the 1970s due to the high toxicity of most PCB congeners and mixtures. PCBs are classified as persistent organic pollutants which bio-accumulate in animals.
PV: Photovoltaics; panels which convert light into electricity, commonly known as solar panels.
Repex: Replacement Expenditure forecasting approach.
Ripple control system: a system used to control the electrical load on the network by, for example, switching domestic water heaters, or by signalling 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.
SDP: Service Delivery Partners.
SDC: Selwyn District Council; the territorial authority for the Selwyn District of New Zealand.
STATCOM: Static Synchronous Compensator; a power electronic device which regulates voltage by providing or absorbing reactive power.
SAMP: Strategic Asset Management Plan; a document translating organisational objectives into asset management strategy.
Transformer: a device that changes voltage up to a higher voltage or down to a lower voltage.
Transpower: the state owned enterprise that operates New Zealand's transmission network. Transpower delivers electricity from generators to grid exit points (GXPs) on distribution networks throughout the country.
Voltage: electric pressure; the force which causes current to flow through an electrical conductor.
Voltage drop: is the reduction in voltage in an electrical circuit between the source and load.
Voltage regulator: an electrical device that keeps the voltage at which electricity is supplied to customers at a constant level, regardless of load fluctuations.
ZS: Zone substation; a major substation where either; voltage is transformed from 66 or 33 kV to 11 kV, two or more incoming 11 kV.

Appendix B – Schedules 11-15

Schedule 11a Report on forecast capital expenditure

Schedule 11a: Report on forecast capital expenditure

11a(i): Expenditure on Assets Forecast

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		$000 (in nominal dollars)										
	Consumer connection	42,936	39,383	40,274	41,643	43,093	45,373	46,385	47,555	48,641	49,828	50,024
	System growth	36,678	16,998	21,255	32,591	36,001	34,880	25,686	16,758	14,229	12,790	11,069
	Asset replacement and renewal	65,343	82,366	99,238	118,635	132,185	134,394	130,747	136,484	140,645	138,480	150,758
	Asset relocations	4,143	4,298	4,446	4,612	4,782	4,958	5,141	5,331	5,527	5,732	5,944
	Reliability, safety and environment:											
	Quality of supply	3,355	1,102	1,868	2,029	2,132	2,238	2,572	2,491	2,118	1,979	1,954
	Legislative and regulatory	0	0	0	0	0	0	0	0	0	0	0
	Other reliability, safety and environment	6,685	4,166	1,100	1,235	1,376	1,523	1,444	1,420	1,455	1,491	1,528
	Total reliability, safety and environment	10,040	5,268	2,968	3,264	3,508	3,761	4,016	3,912	3,574	3,470	3,482
	Expenditure on network assets	159,139	148,314	168,181	200,745	219,568	223,366	211,975	210,039	212,616	210,300	221,277
	Expenditure on non-network assets	18,256	18,710	19,195	13,695	11,772	12,939	10,883	12,980	10,992	13,323	10,810
	Expenditure on assets	177,395	167,024	187,376	214,440	231,340	236,304	222,858	223,020	223,608	223,624	232,088
plus	Cost of financing	4,814	3,934	4,644	5,111	5,161	4,833	4,180	4,684	4,226	4,299	4,107
less	Value of capital contributions	13,648	13,423	14,647	15,517	16,066	16,626	17,055	17,534	17,994	18,490	18,993
plus	Value of vested assets	0	0	0	0	0	0	0	0	0	0	0
	Capital expenditure forecast	168,561	157,535	177,374	204,034	220,435	224,511	209,983	210,170	209,840	209,433	217,201
	Assets commissioned	160,200	149,233	166,726	187,755	224,266	226,307	228,925	196,177	222,419	204,093	223,160
		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
		$000 (in constant prices)										
	Consumer connection	42,936	38,605	39,308	39,887	40,475	41,787	41,886	42,103	42,221	42,402	41,730
	System growth	36,678	16,630	20,580	30,787	33,391	31,578	22,680	14,402	12,029	10,581	8,915
	Asset replacement and renewal	65,343	80,417	95,459	111,585	121,593	120,777	114,687	116,916	117,680	113,096	120,389
	Asset relocations	4,143	4,201	4,261	4,322	4,383	4,445	4,508	4,572	4,637	4,703	4,770
	Reliability, safety and environment:											
	Quality of supply	3,355	1,074	1,775	1,881	1,929	1,977	2,217	2,096	1,739	1,586	1,528
	Legislative and regulatory	0	0	0	0	0	0	0	0	0	0	0
	Other reliability, safety and environment	6,685	4,059	1,045	1,145	1,245	1,345	1,245	1,195	1,195	1,195	1,195
	Total reliability, safety and environment	10,040	5,134	2,820	3,026	3,174	3,322	3,462	3,291	2,934	2,781	2,723
	Expenditure on network assets	159,139	144,987	162,428	189,606	203,015	201,908	187,223	181,285	179,501	173,563	178,527
	Expenditure on non-network assets	18,256	18,180	18,156	12,617	10,570	11,324	9,285	10,794	8,909	10,524	8,322
	Expenditure on assets	177,395	163,168	180,584	202,224	213,585	213,233	196,508	192,078	188,410	184,088	186,849
	Subcomponents of expenditure on assets (where known)											
	Energy efficiency and demand side management, reduction of energy losses											
	Overhead to underground conversion											
	Research and development											

Difference between nominal and constant price forecasts	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	$000										
Consumer connection	0	779	966	1,757	2,619	3,586	4,499	5,452	6,420	7,427	8,294
System growth	0	368	675	1,804	2,610	3,302	3,006	2,355	2,200	2,209	2,154
Asset replacement and renewal	0	1,949	3,778	7,050	10,592	13,618	16,060	19,569	22,965	25,384	30,369
Asset relocations	0	96	185	290	399	513	633	758	890	1,029	1,174
Reliability, safety and environment:											
Quality of supply	0	28	93	148	203	261	355	395	379	393	426
Legislative and regulatory	0	0	0	0	0	0	0	0	0	0	0
Other reliability, safety and environment	0	107	55	90	131	178	199	225	260	296	333
Total reliability, safety and environment	0	135	147	238	334	439	554	621	639	689	759
Expenditure on network assets	0	3,326	5,752	11,139	16,553	21,458	24,752	28,755	33,115	36,737	42,750
Expenditure on non-network assets	0	530	1,040	1,078	1,202	1,614	1,598	2,187	2,083	2,799	2,488
Expenditure on assets	0	3,856	6,792	12,216	17,755	23,072	26,350	30,941	35,198	39,536	45,238

11a(ii): Consumer Connection

		$000 (in constant prices)					
	*Consumer types defined by EDB**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	Consumer Connection	42,936	38,605	39,308	39,887	40,475	41,787
	[EDB consumer type]						
	[EDB consumer type]						
	[EDB consumer type]						
	[EDB consumer type]						
	**include additional rows if needed*						
	Consumer connection expenditure	42,936	38,605	39,308	39,887	40,475	41,787
less	Capital contributions funding consumer connection	10,385	9,839	10,877	11,382	11,551	11,715
	Consumer connection less capital contributions	32,551	28,766	28,431	28,504	28,923	30,072

11a(iii): System Growth

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	Subtransmission	11,772	711	59	459	459	0
	Zone substations	15,820	4,301	4,783	8,046	11,367	5,271
	Distribution and LV lines	567	740	753	729	734	833
	Distribution and LV cables	6,183	8,550	11,024	14,283	14,805	18,956
	Distribution substations and transformers	743	1,188	2,257	3,816	3,814	3,811
	Distribution switchgear	1,592	1,140	1,703	3,454	2,213	2,706
	Other network assets	0	0	0	0	0	0
	System growth expenditure	36,678	16,630	20,580	30,787	33,391	31,578
less	Capital contributions funding system growth	0	0	0	0	0	0
	System growth less capital contributions	36,678	16,630	20,580	30,787	33,391	31,578

11a(iv): Asset Replacement and Renewal

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
		$000 (in constant prices)					
	Subtransmission	13,788	8,599	18,036	24,007	23,151	22,359
	Zone substations	5,893	16,490	13,589	12,375	16,226	12,799
	Distribution and LV lines	21,654	25,096	26,337	28,289	29,376	30,114
	Distribution and LV cables	2,108	5,897	8,044	10,149	11,171	11,439
	Distribution substations and transformers	1,820	3,094	3,610	4,225	4,148	4,565
	Distribution switchgear	15,413	13,291	17,058	22,518	26,533	28,254
	Other network assets	4,669	7,949	8,787	10,022	10,988	11,248
	Asset replacement and renewal expenditure	65,343	80,417	95,459	111,585	121,593	120,777
less	Capital contributions funding asset replacement and renewal	0	0	0	0	0	0
	Asset replacement and renewal less capital contributions	65,343	80,417	95,459	111,585	121,593	120,777

11a(v): Asset Relocations

	Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		$000 (in constant prices)					
	Asset Relocations	4,143	4,201	4,261	4,322	4,383	4,445
	[Description of material project or programme]						
	[Description of material project or programme]						
	[Description of material project or programme]						
	[Description of material project or programme]						
	*include additional rows if needed						
	All other project or programmes - asset relocations						
	Asset relocations expenditure	4,143	4,201	4,261	4,322	4,383	4,445
less	Capital contributions funding asset relocations	3,264	3,310	3,357	3,405	3,453	3,502
	Asset relocations less capital contributions	879	892	904	917	930	943

11a(vi): Quality of Supply

	Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		$000 (in constant prices)					
	Quality of Supply	3,355	1,074	1,775	1,881	1,929	1,977
	[Description of material project or programme]						
	[Description of material project or programme]						
	[Description of material project or programme]						
	[Description of material project or programme]						
	*include additional rows if needed						
	All other projects or programmes - quality of supply						
	Quality of supply expenditure	3,355	1,074	1,775	1,881	1,929	1,977
less	Capital contributions funding quality of supply	0	0	0	0	0	0
	Quality of supply less capital contributions	3,355	1,074	1,775	1,881	1,929	1,977

11a(vii): Legislative and Regulatory

	Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		$000 (in constant prices)					
	[Description of material project or programme]						
	[Description of material project or programme]						
	[Description of material project or programme]						
	[Description of material project or programme]						
	[Description of material project or programme]						
	*include additional rows if needed						
	All other projects or programmes - legislative and regulatory						
	Legislative and regulatory expenditure	0	0	0	0	0	0
less	Capital contributions funding legislative and regulatory						
	Legislative and regulatory less capital contributions	0	0	0	0	0	0

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

$000 (in constant prices)

Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Other Reliability, Safety and Environment	6,685	4,059	1,045	1,145	1,245	1,345
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
*include additional rows if needed						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	6,685	4,059	1,045	1,145	1,245	1,345
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	6,685	4,059	1,045	1,145	1,245	1,345

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5

11a(ix): Non-Network Assets

Routine expenditure

$000 (in constant prices)

Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Routine ICT	9,567	13,581	11,046	8,554	6,993	7,573
Network Transformation	856	1,211	1,405	1,336	1,180	1,291
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
*include additional rows if needed						
All other projects or programmes - routine expenditure	7,833	3,389	3,245	1,827	2,397	2,460
Routine expenditure	18,256	18,180	15,696	11,717	10,570	11,324

Atypical expenditure

Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Head Office Building Extension	0	0	2,460	900	0	0
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
*include additional rows if needed						
All other projects or programmes - atypical expenditure						
Atypical expenditure	0	0	2,460	900	0	0
Expenditure on non-network assets	18,256	18,180	18,156	12,617	10,570	11,324

Schedule 11b Report on forecast operational expenditure

Schedule 11b: Report on forecast operational expenditure

Operational Expenditure Forecast	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	$000 (in nominal dollars)										
Service interruptions and emergencies	12,754	12,917	13,418	13,938	14,475	15,032	15,611	16,212	16,836	17,484	18,157
Vegetation management	5,184	7,314	8,752	10,369	11,032	11,555	12,087	12,427	12,806	13,232	13,637
Routine and corrective maintenance and inspection	13,574	16,683	19,279	19,907	20,259	21,874	20,876	20,045	20,863	21,531	22,241
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	31,512	36,914	41,449	44,215	45,766	48,460	48,573	48,684	50,504	52,247	54,035
System operations and network support	21,626	22,937	24,606	28,495	29,183	29,970	29,958	30,387	30,915	31,471	32,353
Business support	37,170	42,519	48,331	50,135	52,332	54,449	54,776	56,034	57,505	58,987	60,939
Non-network solutions provided by a related party or third party	-	-	-	406	946	223	1,001	279	508	741	312
Non-network opex	58,796	65,457	72,937	79,036	82,461	84,642	85,735	86,700	88,928	91,200	93,603
Operational expenditure	90,309	102,371	114,386	123,251	128,227	133,103	134,308	135,384	139,432	143,447	147,638

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	$000 (in constant prices)										
Service interruptions and emergencies	12,754	12,607	12,786	12,968	13,152	13,339	13,528	13,720	13,915	14,113	14,313
Vegetation management	5,184	7,132	8,331	9,638	10,017	10,250	10,475	10,522	10,593	10,694	10,767
Routine and corrective maintenance and inspection	13,574	16,303	18,417	18,591	18,498	19,529	18,225	17,111	17,413	17,571	17,748
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	31,512	36,043	39,534	41,197	41,667	43,118	42,228	41,354	41,922	42,378	42,828
System operations and network support	21,626	22,449	23,576	26,727	26,800	26,949	26,375	26,194	26,093	26,008	26,178
Business support	37,170	41,551	46,189	46,866	47,866	48,733	47,974	48,022	48,224	48,404	48,931
Non-network solutions provided by a related party or third party	-	-	-	380	865	200	876	239	426	608	250
Non-network opex	58,796	64,000	69,764	73,972	75,530	75,881	75,225	74,455	74,743	75,020	75,359
Operational expenditure	90,309	100,043	109,298	115,170	117,197	119,000	117,454	115,809	116,665	117,399	118,187

Subcomponents of operational expenditure (where known)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Energy efficiency and demand side management, reduction of energy losses											
Direct billing*											
Research and Development											
Insurance											

** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

Difference between nominal and real forecasts	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	$000										
Service interruptions and emergencies	-	310	632	970	1,323	1,693	2,082	2,491	2,921	3,371	3,844
Vegetation management	-	182	421	731	1,015	1,304	1,611	1,905	2,212	2,538	2,870
Routine and corrective maintenance and inspection	-	380	862	1,317	1,761	2,344	2,651	2,934	3,450	3,959	4,493
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	-	872	1,915	3,017	4,099	5,342	6,345	7,330	8,583	9,869	11,207
System operations and network support	-	488	1,030	1,768	2,383	3,022	3,583	4,193	4,822	5,463	6,175
Business support	-	969	2,143	3,269	4,467	5,716	6,802	8,012	9,281	10,583	12,008
Non-network solutions provided by a related party or third party	-	-	-	27	81	23	124	40	82	133	61
Non-network opex	-	1,457	3,173	5,064	6,931	8,761	10,510	12,245	14,185	16,179	18,244
Operational expenditure	-	2,328	5,088	8,081	11,029	14,103	16,855	19,575	22,768	26,048	29,451

Schedule 11c Cybersecurity expenditure

Provided directly to the Commerce Commission.

Schedule 12a Report on asset condition

SCHEDULE 12a: REPORT ON ASSET CONDITION

Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade) H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
All	Overhead Line	Concrete poles / steel structure	No.	1.13%	0.94%	5.13%	7.20%	85.60%	-	3	3.12%
All	Overhead Line	Wood poles	No.	1.85%	3.21%	11.67%	18.28%	64.99%	-	3	7.61%
All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	-
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.82%	0.57%	3.04%	4.80%	89.78%	-	3	1.47%
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	0.05%	0.16%	2.43%	9.72%	87.64%	-	3	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	13.14%	18.43%	68.43%	-	-	-	3	58.51%
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	3.24%	7.81%	42.29%	35.18%	11.48%	-	3	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	N/A	-
HV	Zone substation Buildings	Zone substations up to 66kV	No.	2.38%	9.52%	38.10%	29.76%	20.24%	-	3	33.33%
HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	56.25%	43.75%	-	3	-
HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	34.62%	7.69%	34.62%	-	23.08%	-	3	61.54%
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	100.00%	-	N/A	-
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	27.66%	0.85%	10.21%	5.53%	55.74%	-	3	34.89%
HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	6.67%	-	0.74%	32.59%	60.00%	-	3	8.89%
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	8.03%	0.88%	14.45%	37.81%	38.83%	-	3	3.65%
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-

Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
				Asset condition at start of planning period (percentage of units by grade)							
HV	Zone Substation Transformer	Zone Substation Transformers	No.	0.06%	0.15%	1.13%	3.28%	95.38%	-	2	1.70%
HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	-	-	-	-	N/A	-
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	0.72%	1.49%	7.89%	14.34%	75.56%	-	2	6.36%
HV	Distribution Line	SWER conductor	km	0.07%	0.16%	1.19%	5.07%	93.51%	-	3	0.41%
HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.90%	1.84%	8.87%	15.67%	72.72%	-	3	3.37%
HV	Distribution Cable	Distribution UG PILC	km	-	-	-	-	-	-	N/A	-
HV	Distribution Cable	Distribution Submarine Cable	km	0.00%	0.01%	0.29%	3.62%	96.08%	-	3	-
HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	5.28%	10.41%	32.58%	22.78%	28.96%	-	3	12.20%
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	0.95%	1.91%	9.15%	20.01%	67.98%	-	3	3.67%
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.72%	1.68%	9.69%	12.78%	75.13%	-	3	3.06%
HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	71.07%	-	-	1.52%	27.41%	-	3	35.53%
HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.86%	1.74%	8.23%	11.85%	77.32%	-	3	4.47%
HV	Distribution Transformer	Pole Mounted Transformer	No.	0.29%	0.72%	4.52%	8.70%	85.77%	-	3	1.87%
HV	Distribution Transformer	Ground Mounted Transformer	No.	33.67%	19.87%	27.90%	15.88%	2.68%	-	3	27.53%
HV	Distribution Transformer	Voltage regulators	No.	0.55%	1.20%	6.80%	11.67%	79.78%	-	3	2.60%
HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.26%	0.62%	3.97%	7.92%	87.23%	-	2	1.71%
LV	LV Line	LV OH Conductor	km	0.01%	0.02%	0.34%	2.12%	97.51%	-	3	0.09%
LV	LV Cable	LV UG Cable	km	0.68%	1.54%	8.76%	15.19%	73.83%	-	2	3.88%
LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.43%	6.85%	13.70%	47.93%	31.09%	-	2	0.43%
LV	Connections	OH/UG consumer service connections	No.	13.15%	3.55%	23.03%	23.66%	36.61%	-	3	11.30%
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	12.06%	6.51%	64.87%	13.96%	2.60%	-	3	24.90%
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	8.39%	14.99%	42.96%	27.29%	6.37%	-	3	22.43%
All	Capacitor Banks	Capacitors including controls	No.	13.33%	-	48.89%	22.22%	15.56%	-	3	15.56%
All	Load Control	Centralised plant	Lot	-	-	-	-	-	-	N/A	-
All	Load Control	Relays	No.	-	-	-	-	-	-	N/A	-
All	Civils	Cable Tunnels	km							[Select one]	

Schedule 12b Report on forecast capacity

12b(i): System Growth - Zone Substations

Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
ADDINGTON #1	19	Winter	37	N-1	No constraint	18	Winter	16	N-1	Winter	12	15	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
ADDINGTON #2	23	Winter	30	N-1	No constraint	7	Winter	5	N-1	Winter	1	5	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
ANNAT	4	Summer	8	N-1 switched	Security	4	Summer	4	N-1 switched	Summer	4	4	N-1 switched	Security	1	Distribution back-up circuit capacity	Other non-traditional solution	Solution confirmed	Not applicable	Project in FY27 to install STATCOM to restore switched N-1 capability
ARMAGH	22	Winter	39	N-1	No constraint	17	Winter	15	N-1	Winter	11	14	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
BANKSIDE	4	Summer	9	N-1 switched	No constraint	6	Summer	6	N-1 switched	Summer	6	6	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
BARNETT PARK	10	Winter	15	N-1 switched	No constraint	5	Winter	6	N-1 switched	Winter	3	5	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
BELFAST	13	Winter	15	N-1 switched	No constraint	2	Winter	2	N-1 switched	Winter	-2	2	N-1 switched	Security	7	Other	Undecided	No active planning	Not applicable	Transformer capacity is 40MVA but operational limit is 15MVA due to switched N-1. Loading to be monitored and offload opportunities to be assessed
BROMLEY	39	Winter	48	N-1	No constraint	9	Winter	5	N-1	Winter	-1	4	N-1	Security	9	Zone substation transformer	Undecided	No active planning	Not applicable	Loading actively monitored to determine solution type required
BROOKSIDE	9	Summer	10	N-1 switched	No constraint	1	Summer	1	N-1 switched	Summer	1	1	N-1 switched	Security	10+	Not applicable	Not required	Not applicable	Not applicable	
DALLINGTON	24	Winter	39	N-1	Security	14	Winter	13	N-1	Winter	9	12	N-1	Security	1	Subtransmission circuit	Not required	No active planning	Not applicable	Security breach due to site loading requiring full N-1 but only switchable N-1 available. Rapid switchable restoration available for 66kV circuit fault so currently uneconomic to resolve security gap
DARFIELD	6	Winter	10	N-1 switched	No constraint	4	Winter	4	N-1 switched	Winter	2	4	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
DIAMOND HARBOUR	3	Winter	9	N-1 switched	No constraint	5	Winter	6	N-1 switched	Winter	5	5	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
DUNSANDEL	19	Summer	24	N-1	No constraint	5	Summer	4	N-1	Summer	-7	2	N-1	Security	6	Zone substation transformer	Undecided	No active planning	Not applicable	Large customer connection causing forecast potential security breach. Timing and scope to be determined of solution to be determined by customer capacity need
DUVAUCHELLE	4	Winter	8	N-1 switched	No constraint	4	Winter	4	N-1 switched	Winter	4	4	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
FENDALTON	37	Winter	42	N-1	No constraint	5	Winter	4	N-1	Winter	-1	2	N-1	No constraint	10+	Zone substation transformer	Divert load to alternative substation	No active planning	Not applicable	Marginal forecast security breach. Opportunities for 11kV load transfer to be assessed.
GREENDALE	7	Summer	10	N-1 switched	No constraint	3	Summer	3	N-1 switched	Summer	3	3	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
HALSWELL	23	Winter	24	N-1	No constraint	1	Winter	1	N-1	Winter	-1	-2	N-1	Security	7	Zone substation transformer	Undecided	Planning stage	1 - 3 years	Investigation and economic analysis required for forecast security breach to determine network and non-network option feasibility.
HAWTHORNDEN	33	Winter	39	N-1	No constraint	6	Winter	2	N-1	Winter	-3	-2	N-1	Security	6	Zone substation transformer	Divert load to alternative substation	Planning stage	Not applicable	Minor project to create post-contingency switching and/or reinforcement options being assessed
HEATHCOTE	29	Winter	39	N-1	No constraint	10	Winter	8	N-1	Winter	-9	7	N-1	Security	7	Zone substation transformer	Undecided	Planning stage	Not applicable	Forecast security breach driven by major customer growth. Timing and solution(s) to be confirmed
HIGHFIELD	9	Summer	10	N-1 switched	No constraint	1	Summer	1	N-1 switched	Summer	-1	0	N-1 switched	Capacity	7	Zone substation transformer	Network upgrade	Solution confirmed	Not applicable	Capacity breach resolved through Malvern industrial growth major project
HILLS RD	8	Summer	10	N-1 switched	No constraint	2	Summer	2	N-1 switched	Summer	2	2	N-1 switched	Security	6	Distribution back-up circuit capacity	Undecided	Planning stage	Not applicable	Forecast security breach with lower voltage threshold exceeded at network extremities during subtransmission or transformer contingencies at peak load times. Load growth being monitored and modelled for contingent outages. Options being developed.
HOON HAY	32	Winter	39	N-1	No constraint	7	Winter	9	N-1	Winter	5	7	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
HORNBY	15	Winter	23	N-1	No constraint	7	Winter	7	N-1	Winter	4	6	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
HORORATA	9	Summer	10	N-1 switched	No constraint	0	Summer	1	N-1 switched	Summer	1	1	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	

ILAM	14	Winter	15	N-1	Security	1	Winter	6	N-1	Winter	3	5	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
KILLINCHY	10	Summer	10	N-1 switched	No constraint	0	Summer	1	N-1 switched	Summer	-1	0	N-1 switched	Capacity	7	Zone substation transformer	Network upgrade	Solution confirmed	Not applicable	Business case developed for a forecast capacity upgrade in FY36. Operational capacity to be lifted to 15MVA
KIMBERLEY	16	Summer	24	N-1	No constraint	8	Summer	9	N-1	Summer	9	9	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
LANCASTER	23	Winter	48	N-1	Security	24	Winter	21	N-1	Winter	16	20	N-1	Security	1	Subtransmission circuit	Network upgrade	Solution confirmed	Not applicable	Rapid switchable N-1 available for a 66kV circuit fault. N-1 to be provided in FY28
LARCOMB	25	Winter	24	N-1	Security	-1	Winter	-1	N-1	Winter	-11	-3	N-1	Security	3	Zone substation transformer	Divert load to alternative substation	Solution confirmed	Not applicable	Security breach to be resolved with new Rolleston (Burnham) zone substation
LINCOLN	11	Winter	15	N-1 switched	No constraint	4	Winter	2	N-1 switched	Winter	-2	-2	N-1	Security	1	Zone substation transformer	Network upgrade	Solution confirmed	Not applicable	Forecast load exceeds 15MVA requiring N-1. Security breach to be resolved with replacement new Greenpark zone substation
LITTLE RIVER	2	Summer	3	N-1	No constraint	1	Summer	2	N-1 switched	Summer	2	2	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
MCFADDENS	35	Winter	39	N-1	No constraint	3	Winter	3	N-1	Winter	-4	2	N-1	Security	7	Zone substation transformer	Divert load to alternative substation	No active planning	Not applicable	If required, load transfer options to be assessed
MIDDLETON	30	Winter	46	N-1	No constraint	16	Winter	10	N-1	Winter	2	9	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
MILTON	37	Winter	42	N-1	No constraint	5	Winter	4	N-1	Winter	-2	3	N-1	Security	9	Zone substation transformer	Undecided	No active planning	Not applicable	Loading actively monitored to determine solution type required
MOFFETT ST	19	Summer	23	N-1	No constraint	3	Summer	2	N-1	Summer	-1	2	N-1	Security	9	Zone substation transformer	Divert load to alternative substation	Solution confirmed	Not applicable	Forecast security breach to be resolved through the transfer of load to the proposed Templeton ZS as part of the Templeton commercial growth business case
MOTUKARARA	3	Summer	15	N-1 switched	No constraint	12	Summer	12	N-1	Summer	11	11	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
OXFORD-TUAM	22	Winter	39	N-1	No constraint	17	Winter	14	N-1	Winter	9	13	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
PAPANUI	36	Winter	50	N-1	No constraint	14	Winter	13	N-1	Winter	8	10	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
PREBBLETON	9	Winter	15	N-1 switched	No constraint	6	Winter	5	N-1 switched	Winter	3	5	N-1 switched	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
RAWHITI	34	Winter	39	N-1	Security	5	Winter	6	N-1	Winter	4	4	N-1	Security	10+	Subtransmission circuit	Not required	Not applicable	Not applicable	Rapid switchable N-1 available for a 66kV circuit fault. Not currently economical to provide full N-1
ROLLESTON	14	Winter	15	N-1 switched	No constraint	1	Winter	-1	N-1 switched	Winter	-6	-5	N-1 switched	Security	1	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	Security breach to be resolved with new Rolleston (Burnham) zone substation replacement. Operational capacity will be lifted to 24MVA providing N-1
SHANDS RD	17	Winter	23	N-1	No constraint	6	Winter	5	N-1	Winter	2	5	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
SOCKBURN	25	Winter	37	N-1	No constraint	12	Winter	9	N-1	Winter	4	8	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
SPRINGSTON	12	Winter	24	N-1	No constraint	11	Winter	6	N-1	Winter	3	5	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
TE PIRITA	9	Summer	10	N-1 switched	No constraint	1	Summer	1	N-1 switched	Summer	0	0	N-1 switched	Security	6	Distribution back-up circuit capacity	Undecided	No active planning	Not applicable	Forecast security breach with lower voltage threshold exceeded at network extremities during subtranmission or transformer contingencies at peak load times. Load growth being monitored and modelled for contingent outages.
WAIMAKARIRI	24	Winter	48	N-1	Security	24	Winter	22	N-1 switched	Winter	17	21	N-1	Security	10+	Subtransmission circuit	Not required	No active planning	Not applicable	Security breach due to site loading requiring full N-1 but only switchable N-1 available. Rapid switchable restoration available for 66kV circuit fault so currently uneconomic to resolve security gap
WEEDONS	16	Winter	24	N-1	No constraint	7	Winter	4	N-1	Winter	-1	3	N-1	Security	9	Zone substation transformer	Divert load to alternative substation	Implementation stage	Not applicable	Security breach forecast due to distribution network configuration. Loading to be reduced with new Rolleston ZS project

Schedule 12c Report on forecast network demand

Schedule 12c: Report on forecast network demand

12c(i): Consumer Connections

Number of ICPs connected during year by consumer type

*Consumer types defined by EDB**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	Number of connections					
Streetlighting	16	5	5	5	5	5
General	6,700	6,034	6,107	6,198	6,290	6,379
Irrigation	5	5	5	5	5	5
Major Customer	20	20	20	20	20	20
Large Capacity	3	3	3	3	3	3
Connections total	6,744	6,067	6,140	6,231	6,323	6,412

**include additional rows if needed*

Distributed generation	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Number of connections made in year	1,532	1,176	1,191	1,145	1,029	907
Capacity of distributed generation installed in year (MVA)	13	16	156	6	6	5

12c(ii): System Demand

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	Maximum coincident system demand (MW)						
	GXP demand	697	718	740	756	780	807
plus	Distributed generation output at HV and above			0.14	2	2	3
	Maximum coincident system demand	697	718	740	758	782	810
less	Net transfers to (from) other EDBs at HV and above						
	Demand on system for supply to consumers' connection points	697	718	740	758	782	810
	Electricity volumes carried (GWh)						
	Electricity supplied from GXPs	3,632	3,847	4,034	4,198	4,445	4,662
less	Electricity exports to GXPs						
plus	Electricity supplied from distributed generation	82	67	73	78	81	83
less	Net electricity supplied to (from) other EDBs						
	Electricity entering system for supply to ICPs	3,714	3,914	4,107	4,275	4,525	4,746
less	Total energy delivered to ICPs	3,475	3,680	3,860	4,016	4,253	4,461
	Losses	239	234	248	259	273	285
	Load factor	61%	62%	63%	64%	66%	67%
	Loss ratio	6.4%	6.0%	6.0%	6.1%	6.0%	6.0%

Schedule 12d Report forecast interruptions and duration

Schedule 12d Report forecast interruptions and duration						
	Current Year CY	**CY+1**	**CY+2**	**CY+3**	**CY+4**	**CY+5**
SAIDI						
Class B (planned interruptions on the network)	29.55	26.31	26.31	26.31	26.31	26.31
Class C (unplanned interruptions on the network)	73.61	51.81	51.81	51.81	51.81	51.81
SAIFI						
Class B (planned interruptions on the network)	0.123	0.087	0.087	0.087	0.087	0.087
Class C (unplanned interruptions on the network)	0.570	0.621	0.621	0.621	0.621	0.621

Schedule 13 Report on asset management maturity

Schedule 13: Report on asset management maturity

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3.5	Asset Management Policy is available and has recently been updated. AM Policy is aligned with the latest Statement of Intent document. Orion has a well-structured Asset Management Policy document. It covers off all the required focus areas and is aligned with current Orion business strategies and objectives. The AM Policy document is reference consistently in many asset related documents. The policy document is aligned with current business objectives, and explicitly seeks alignment with ISO 55000 and ISO 31000. Upon review against the CPP preparatory materials, no fundamental policy-level weaknesses are apparent. Policy documentation is sound with clear articulation of asset management principles. While organisational restructuring affects implementation, this does not diminish the quality of the policy framework itself.	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?	2.5	Orion have recently created a separate SAMP document. It is well structured and aligned with the AM Policy. The SAMP's interaction with other AM processes is well illustrated in the document. This is a document which many of Orion's key staff and stakeholders will soon be able to reference as required, to gain insights into Orion's AMS. The SAMP represents strategic direction setting rather than demonstrated strategic management capability. The CPP-driven development timeline indicates this is foundational work awaiting validation through implementation cycles. Currently, only network development and lifecycle strategies are directly linked to the SAMP. Other organisational strategies and policies in ICT, Network Transformation, and business support (people) are not yet connected to the SAMP, representing gaps in demonstrating consistency across Orion. Although the AMP provides a solid foundation, and key staff and stakeholders can reference it for insights into the AMS, the incomplete linkages mean Orion cannot demonstrate that the AM Strategy is fully consistent with all appropriate policies and strategies as Level 3 requires. They recognise this gap, and will be working to establish the remaining linkages via first developing and documenting the AMS Scope.	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.
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	Orion's new SAMP is structured well and highlights strategies and key objectives for all of their asset classes. It provides insights into how assets will be managed throughout their lifecycle. We also note that while Orion report on Non-Network lifecycle strategies in their AMP regulatory disclosure, they do not have specific, and documented, Asset Class Strategies for all non-network asset types.	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?	3.25	Orion have comprehensive Asset Management Plans (AMPs). The latest AMP 2025 is an update AMP as is approved by the Commerce Commission. The last full AMP was published in 2024 While the AMP 2024 is comprehensive, the necessity of a significant value CPP application to address deferred maintenance warrants consideration of the scoring of this section. An AMP that has allowed accumulation of renewal deferrals requiring exceptional funding mechanisms does not support "Optimising" level scoring. The acknowledged need for significant AMP 2026 revision further supports this adjustment.	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).

Schedule 13: Report on asset management maturity (cont'd)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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.

Schedule 13: Report on asset management maturity

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
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?	3.25	The Orion AMP's are published on their web page for all to access. They also undertake specific consultation both before and post final AMP publication with key Stakeholders. There is always room for improvement here.	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?	3.25	Yes the specific responsibility for the development of the next Amps documented for the Network Strategy and Investment Manager role. As Orion now have a specific asset management team, many of this team will provide focused input into the next AMP for 2026. The establishment of the AM Team surpasses the requirements of PAS 55. Orion have established excellent processes for the updating on both Full and Update AMPs as required by the regulator.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2.5	Orion actively updates it's vast array of asset class and portfolio documentation and process instructions. These link directly with the latest AMP. The AMP is developed after all of the higher hierarchy documents (Business Plans, SOI and AM Policy etc.) have been updated and approved by top management. The AMP brings all of that strategy and direction together to provide even more detail and specific direction. As well as reporting on past asset performance. While Orion have arrangements in place for AMP implementation, these arrangements do not yet meet the level 3 standard for efficient & cost-effective implementation. Their current process is resource-intensive, requiring excessive iterations through forecasts, reviews, and approvals, meaning that implementation is not efficient nor cost-effective. Changes to functional policies, standards, processes and AMIS drive changes to the AMP, rather than the AMP driving necessary organisational changes; this reactive approach, means Orion cannot claim to "fully cover all requirements". Orion acknowledge these weaknesses and are actively working to resolve them through a comprehensive review of how AMP2026 and future AMPs will be produced.	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?	3.25	Orion are very focused on effective contingency planning, due to the nature of their business and as a result of the past events such as the Christchurch earthquakes and other natural events in the area. Orion has continued to improve their resilience to business interruption by targeting three main focus areas and ensuring that they have the right systems, people and processes in place to quickly and effectively respond to all types of events. They have also recently completed Resilience Management Maturity Assessment Tool (RMMAT) process which benchmarked them highly against peer EDB's. We have previously recognised strong contingency planning capability due to Canterbury earthquakes experience (RMMAT score 3.01 exceeds sector average 2.55). Upon review of CPP documentation, "Building network resilience to reduce major outage risk" is identified as a core driver, specifically citing high earthquake risk requiring substantial investment to strengthen the 66kV network. The requirement for significant capital investment to close resilience gaps warrants reconsideration of the "Optimising" score. Historical contingency planning excellence is acknowledged. However, the CPP explicitly identifies continuing resilience vulnerabilities requiring substantial investment (66kV network strengthening). Outstanding resilience gaps requiring a significant investment programme indicate remaining development opportunities rather than fully optimised capability. Orion have not updated our contingency plans over the last two years They have only just started looking at infrastructure resilience, taking into account risks and consequences of climate impact.	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.

Schedule 13: Report on asset management maturity (cont'd)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
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	The Orion AMP 2024 – section 2.10 Asset management roles and accountabilities, provides details on how the organisation's governance/management structure is arranged. SAMP provides updated information. The org chart has changed within the last 9 months with the creation of a new Asset Management team which mostly incorporates the old Future Network team, but with some adjustments and realignment of people.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2.5	Orion now has an Asset Management Improvement Plan in place. This document acknowledges that additional roles are required within the AM team. This is being addressed. Unfilled key positions within the AM Team and acknowledged capacity constraints affect organisational structure effectiveness. The challenge in maintaining core AM process improvement momentum while managing CPP workload indicates structural capacity limitations under current demand. A restructured system requiring operational validation appropriately scores at "Competent" threshold pending demonstrated effectiveness under normal business conditions. Orion's restructure in early 2025 is the foundation of the resources Orion needs for their asset management activities as they improve on their journey. However, the current structure may potentially need new roles. For example, they currently do not have any reliability engineers in the organisation. The AMIP will support the development of a process to assess future resource needs, but it is still in a draft state.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Orion undertakes regulate communications both internally and externally to ensure all affect parties are aware of the content of the latest AMPs. E.g. Internally - Staff meetings, asset class focus group meetings. Externally - Customer Advisory Panel, "Powerful Conversations" workshops	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.5	In the past year Orion has made a change to the way they have structured their outsourcing model with their key service delivery partners. They now have a relationship with the "Tight Five" contractors, with Connetics being their designated Primary Service Delivery Partner (PSDP) and the other four contracted companies designated as Service Delivery Partner (SDP). Orion's Procurement team maintains the contract and service level measures for the "Tight Five". Orion's Network Delivery team is responsible for the works programming and delivery of their annual work plan, supported as appropriate by their other teams. The new work flow processes need time to bed in and mature. The model has not been tested against CPP-scale delivery volumes, supporting cautious scoring pending operational validation. Orion have made changes to the way they have structured their outsourcing model, and have continued to focus on improving their relationship with their key contractors, they have not yet implemented controls systematically into the asset management system to ensure outsourced activities are delivered in compliance with the organisational strategy, AM Policy or SAMP. For example, their service delivery partners operate under Master Service Agreements; the conditions (controls) for these contracts are adopted from NZS 3910:2023. While elements of alignment exists, controls are not fully aligned to their organisational strategy, AM Policy or SAMP.	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 (cont'd)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
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)?	3.5	The AMP section 4.2 Planning for changing workforce needs, provides good insights into Orion's future training focuses. Their workforce plan focuses on developing and embedding key processes and systems, and creating an environment for our current and future workforce to thrive by 2028.	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	Competencies of all personnel working on the Orion network is managed by the training Team and updates are uploaded into the PowerOn system. The PowerOn system holds staff and contractors network competency information. Without the correct competencies, work management permits are not issued if competences are not up to date. Orion's training systems and competency management processes ensures that all people working on their network assets are fully competent and appropriately skilled. Orion has well-developed processes to manage the competencies of all personnel (service providers and Orion operators) who work on the physical network. They also have clear competency requirements for operators, and have developed a competency pathway to ensure career and skill progression. However, there are no structured training requirements or processes for general employees - these are at the discretion of the employee and their manager. They have implemented LinkedIn Learning to allow for additional upskilling and cross-training, but no formal learning requirements are in place.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
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?	2.5	Orion continues to strengthen their Talent Programs by ensuring depth in their succession plans and enabling talent mobility via development and growth of their people. Roles have not been formally mapped against a matrix of training and competency requirements. There are internal training courses (Network Access competencies) required to work on specific aspects of the network (HV, LV, Underground, Above ground) and practical training on operating assets but there are some inconsistencies in course content, quality and delivery and a lack of formal training matrix to capture ALL training required and monitor records/ refreshers. Leadership development training is not currently being delivered.	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 (cont'd)

Question 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).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
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?	2.5	Overall Orion is a good communicator and has many processes in place for both internal and external communications. As a community owned organisation, their focus is always on the communities they serve. The following are a few references from the AMP 2024: 3.2 Stakeholder interests: 3.3.1 Customer Advisory Panel 3.3.2 Customer satisfaction research 3.3.3 "Powerful Conversations" workshops Orion see opportunities to improve how they have two-way communication between all relevant parties. For example, currently: - They don't provide the information service delivery partners need in AMP, e.g., quantity of increase - AMP info is not effectively communicated to match the requirements of asset management strategy, plan(s) and process(es) to customers. To close this gap, they are developing a forward works viewer for their service delivery partners, to help them understand Orion's anticipated programme of work and resource appropriately.	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?	2	Orion has detailed asset management documents which are constantly being updated to stay up with new development initiatives. The Orion AMP 2024 – section 2.6 Asset Management Framework, onwards, provides extensive details on how the asset management system exists to ensure all assets within the Orion network are appropriately managed. SAMP is referenced for more up to date information given it's the latest work and has been peer reviewed. Variable documentation maturity across the asset management system prevents higher scoring. Orion are in the process of establishing documentation that comprehensively describes all of the main elements of their AM System and the interactions between them.	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?	2	Orion is transforming their operating model to become an increasingly digital business, modernising their core platforms and leveraging digital services, automation and data intelligence to drive business performance and improve customer outcomes. Edison notes that the selection of the IBM Maximo application for the CMMS function is an extremely good move. Maximo is a long-standing asset management focused tool used by many high achieving infrastructure organizations Many of the key asset management related systems are currently being implemented so it will be a couple of years before these are fully While Orion are transforming their operating model to become an increasingly digital business, they are still in the process of implementing Maximo and ESRI. They have not yet developed requirements relating to the whole life cycle and cover information originating from both internal and external sources for all asset fleets.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	Orion is transforming their operating model to become an increasingly digital business, modernising their core platforms and leveraging digital services, automation and data intelligence to drive business performance and improve customer outcomes. They are in the process of developing effective controls for all asset fleets. Maximo, when fully implemented, will assist with this consistency and ensure that controls are regularly reviewed and improved where necessary. Orion have areas of strength, but they do not have consistent evidence of "effective" controls that are regularly reviewed and improved across all asset fleets, where necessary.	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.

Schedule 13: Report on asset management maturity (cont'd)

Question 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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	Many of Orion's current systems supporting their asset management processes are end of life. Their goal is to modernise the systems supporting the management of their network and uplift their asset management capabilities. It is noted that the selection of the IBM Maximo application for the CMMS function is an extremely good move. Maximo is a long-standing asset management focused tool used by many high achieving infrastructure organizations. Orion are in the process of implementing a process to ensure their asset management information system is relevant to their needs by implementing Maximo. Until this is completed, many of their asset management information systems are at end of life (as outlined in their 2024 AMP), and there are gaps between what the information systems provide and what their organisation needs.	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?	2.5	Due to the nature of Orion's business, risk management is a key focus in everything they do. They are currently further developing their Enterprise Risk Management (ERM) processes and systems. We have previously noted Enterprise Risk Management (ERM) framework development aligned to ISO 31000 principles, and that "A large amount of improvement work is currently being undertaken in the ERM. These processes and integrations need time to mature to see how they perform and deliver benefits to the business. Orion are stronger in some asset fleets and asset lifecycle stages than others. For example, identification and assessment of asset related risk across the asset lifecycle is done but not fully documented. They document some in ACS, business cases and PODs, however, they are not consistently applied across all lifecycle phases, e.g., maintenance, procurement, delivery and etc.	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.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Operational key risks have been identified. Risk information is a key asset decision making tool and is being improved as the new Enterprise Risk Management process is improved and developed. We have previously noted Asset Health and Criticality measures are used "to varying degrees on various asset classes" and that "More work is intended to be done on these measures to help gain more awareness of their benefits." While significant CPP investment is substantially justified by failure risks posed by ageing assets, the ability to effectively use and maintain asset risk information is currently constrained by incomplete systems and acknowledged legacy data limitations. The area is "undergoing a huge amount of improvement." Inconsistent application across asset classes, acknowledged need for enhanced understanding of risk measures, and explicit improvement requirements indicate this capability is developing rather than systematically embedded. Orion's approach to risk assessments feeding into standards/procedures and subsequently training and monitoring activity is not formally mapped and inconsistently applied. There is no central location for risk assessments to be stored and no system to map that these or any controls identified have been captured in new designs/ specifications. The audit process to verify standards are being applied correctly is ad hoc and there is no formal reporting mechanism to demonstrate these are done or corrective actions/ risk reduction activities are being undertaken. Orion do risk assessments, but they don't see a specific link between a risk assessment and a standard change, and the standard change officially happening - no document/change management; they sometimes have a risk assessment and do nothing from it - need to have a mechanism to have risk assessment feed into change (i.e. investigate if change is possible, then move into doing it).	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?	2	Orion currently use an external consultancy to monitor and report on regulatory, and compliance matters so that they can ensure active compliance within the whole of their business. They are aware that there are currently many new statutory requirements being forced onto their industry. They actively provide submissions during consultation period for many of these process reviews by government agencies. They have procedures to identify legal, regulatory, statutory and other asset management requirements, including external consultancy for regulatory monitoring, active participation in government consultation processes, and established relationships with third-party advisors for financial and technical compliance. However, their approach is not adequately systematic or consistently managed across the organisation. For example, while their Engineering Standards contain requirements they must meet, they lack explicit linkages to the underlying legal and regulatory sources (e.g. Transpower, Electricity Industry Participation Code 2010, NZ/AUS Engineering Standards), making it difficult to demonstrate why specific requirements exist and how they connect back to Orion's statutory obligations. Orion's information management is fragmented; they have no integrated view or holistic reporting system to track their compliance positioning across Orion. They rely heavily on SME knowledge and external advisors, rather than systematic controls and documented processes, with no formal mechanism to track and monitor changing requirements beyond individual monitoring and internal education. Orion's AM information system (Maximo) does not yet have the systematic processes needed to store and report on compliance requirements against assets. These gaps mean their requirements are inconsistently managed, despite having foundational procedures in place. They are evaluating the use of a compliance software (e.g. Comply With) to provide a holistic overview and reporting mechanism.	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

Schedule 13: Report on asset management maturity (cont'd)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
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?	2	With the creation of new roles within the Asset Management Team, Asset Class Strategy documents have recently been created or are being created to look at everything relating to the asset class, including asset lifecycle management, maintenance, renewals and continuous improvement. Orion are in the process of implementing or improving processes and procedures to manage and control the implementation of their AMP. For example, while they have a process to show how a project is implemented, they do not have evidence to show the process is effective.	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?	2	Orion's new Asset Management team has developed a whole new group of strategic documents for all of their main asset classes. These cover the whole life cycle of the asset and everything to do with that asset. We have previously noted Asset Class Strategy documents have been recently created or are in development. Past deferral of asset renewal activities during the post-earthquake recovery period has been noted. This historical deferred maintenance accumulation indicates past lifecycle management did not prevent asset deterioration. New strategies have not been tested through complete asset lifecycle implementation cycles, and effectiveness relies substantially on accurate Maximo Job Plan implementation. The accumulation of deferred maintenance necessitating additional future funding mechanisms indicates historical lifecycle management did not prevent asset deterioration. Orion do not carry out preventative (inspections, etc) and corrective (triage/prioritisation) consistently on all asset fleets. While they have pockets of excellence, such as their renewals, some areas are being discussed as part of their CPP application and IAM implementation.	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.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	Orion is currently developing a sweet of new systems to replace outdated legacy systems used to collect and manage asset performance and condition monitoring data. They intend to continue to collect the best possible up to date data, ensure it's quality and make all data available within one data storage source. As more new systems are integrated with each other and share timely clean data, Orion aims to make a step change in it's asset management performance and condition monitoring outputs. This is intended to improve asset management decision making. Orion has traditional collected a lot of asset data, but they are now clear that some of this historic data is not as sound and accurate as it could be, so they are planning to improve these situations over the next few years. We have previously acknowledged plans to replace outdated legacy systems with new platforms (Maximo, GIS). Our assessment has assessment explicitly noted "some data is not of high quality currently, but plans are in place to improve these data sets as new systems are implemented" and that "historic data is not as sound and accurate as it could be." The CPP application is predicated on achieving a "step change" in decision-making through new systems, indicating current monitoring systems require enhancement. Acknowledged current data quality limitations affect performance and condition monitoring effectiveness. Plans for future improvement do not constitute current capability. The necessity to implement comprehensive new systems to achieve adequate monitoring capability indicates current state is at a level 2 scoring currently. Orion are stronger in some asset fleets (especially those that support our 11kV+ network), than others. For example, on their LV network, they are just starting to get more visibility into our network; they are not yet conducting consistent asset performance monitoring and consistent approaches across this fleet. Until Maximo is implemented, they do not yet meet the criteria for level 3.	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?	2	When an asset failure is reported, a specialist team undertakes the investigation, reporting and improvement processes as required. If required processes will be changed, following a rigorous change management process. Orion have a well established process, responsibility and authority for investigation of incidents that result in zone sub / sub transmission outages which are low in probability. However, they do not apply these across the business consistently. For example, other incidents or asset failures e.g., crossarm or insulators, 11kV distribution assets do not trigger an investigation.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Schedule 13: Report on asset management maturity (cont'd)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Business internal audit programme exists and are reported on at high levels of the organisation. Most asset management related activities full within these audits. Asset management processes have their own cycle of review and updates as mentioned earlier in this report. We have noted business internal audit programme exists at senior organisational levels. However, recommendations in the assessment included "More visibility in this area is required," "end-to-end process mapping" should be undertaken using Flowingly, and "more visibility should be available to show how and when audits are undertaken on the asset management system and core processes." The emphasis on ISO 55001 alignment highlights opportunities to enhance audit documentation and visibility. Explicit recommendations for enhanced visibility and systematic process mapping indicate current audit processes provide limited asset management system assurance. While basic audit programmes exist, the systematic, comprehensive AM system auditing required for certification readiness is not yet established. while Orion have an extensive business assurance programme, they cannot demonstrate that their audit procedures cover all appropriate asset-related activities and associated reporting of audit results. For example, various AM related audits took place over the last 3-6 years and there are still a number of action items that have not been closed out. We expect this score to improve in the future as Orion work to implement their AM Improvement Plan and improve their internal audit function capability and scope.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2.5	All asset classes now have strategy documents which outline the required preventative and corrective actions that are required. With the implementation of the new Maximo and GIS systems, more information and data related to specific asset will be available to staff and contractors. Maximo will allow improved planning and scheduling of preventative maintenance (PM) tasks and also enable collection of more detailed corrective information following work on an asset fault or defect (DM) activities. The reliance on future system implementation for process effectiveness, combined with historical renewal deferrals, indicates current corrective and preventative action processes were insufficient to prevent asset deterioration. Enhanced visibility requirements and pending Maximo-enabled improvements indicate current state is at a "Developing" level requiring systematic enhancement. While Maximo will drive future improvement, they do not yet have mechanisms consistently in place across all asset fleets that are effective for the systematic instigation of P & C actions to address root causes of non-compliance or incidents. Orion's focus has historically been on high-risk activities and assets. Maximo will help them drive improvements in this area, when it is fully implemented.	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?	2.5	Orion is developing improved systems to ensure they can better manage their continual improvement activities. In the past they have strived for improvements in these areas but have been constrained by outdated systems and poor data collection and quality. We have previously acknowledged Orion demonstrates commitment to asset management enhancement through multiple initiatives. However, the assessment noted Orion "have been constrained by outdated systems and poor data collection and quality," that "documentation maturity remains variable," "Risk quantification and predictive action flagged as areas requiring continued development," and "Improvement roadmap required to align current practices with ISO 55001:2024 requirements." System improvement is only part of the equation and Orion haven't fully implemented it yet. Risk assessment and performance e.g., reliability etc are all areas they need to uplift.	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 is developing improved systems to ensure they can better manage their continual improvement activities. In the past they have strived for improvements in these areas but have been constrained by outdated systems and poor data collection and quality. We have previously acknowledged Orion demonstrates commitment to asset management enhancement through multiple initiatives. However, the assessment noted Orion "have been constrained by outdated systems and poor data collection and quality," that "documentation maturity remains variable," "Risk quantification and predictive action flagged as areas requiring continued development," and "Improvement roadmap required to align current practices with ISO 55001:2024 requirements." System improvement is only part of the equation and Orion haven't fully implemented it yet. Risk assessment and performance e.g., reliability etc are all areas they need to uplift.	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 (cont'd)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 14a Mandatory explanatory notes on forecast information

Company name: Orion NZ Ltd

For year ended: 31 March 2027

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Our expenditure forecasts are presented in real FY26 dollars (constant prices) throughout this AMP to provide a consistent basis for comparison, unless otherwise noted. To convert these figures to nominal dollars, as used in some of the Schedules, we apply a cost escalation methodology that reflects projected inflation and other economic movements specific to electricity distribution work.

We engaged the Sapere Research Group to provide annual percentage forecasts for key cost inputs including materials (aluminium, copper, steel), labour, and other capital goods. These forecasts are then weighted to create escalation indices tailored to our specific expenditure categories.

For capex, we have defined six primary escalator classes (Labour, Cables, Conductor, Transformers, Switchgear, and Other), which are further weighted within 44 capex categories to reflect the unique cost composition of different asset types.

To ensure the integrity of this approach, weightings are estimated independently of the Sapere percentage forecasts to avoid potential bias.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Our expenditure forecasts are presented in real FY26 dollars (constant prices) throughout this AMP to provide a consistent basis for comparison, unless otherwise noted. To convert these figures to nominal dollars, as used in some of the Schedules, we apply a cost escalation methodology that reflects projected inflation and other economic movements specific to electricity distribution work.

For opex, we applied a similar approach to capex, using four key indices (LCI – All Sectors, PPI – Inputs, Maintenance Labour, and Vegetation Control) weighted across seven opex categories.

To ensure the integrity of this approach, weightings are estimated independently of the Sapere percentage forecasts to avoid potential bias.

Schedule 15 Voluntary explanatory notes

1. This schedule enables EDBs to provide, should they wish to,

   1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1 and 2.5.2;

   1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Orion has no voluntary explanatory notes or additional disclosures to provide under this schedule.

Appendix C – Compliance checklist

Table C.1 Attachment A Asset Management Plan					
ID Clause	**Description**	**Location**	**Section**	**Sub-section**	**Notes**
AMP Design					
This attachment sets out the mandatory disclosure requirements with respect to ***AMPs****. The text in italics provides a commentary on those requirements. The purpose of the commentary is to provide guidance on the expected content of disclosed* ***AMPs****. The commentary has been prepared on the basis that* ***EDBs*** *will implement best practice asset management processes.*					
1.	The core elements of asset management—				
1.1	A focus on measuring **network** performance, and managing the assets to achieve service targets;	2026 AMP	Chapter 5 Chapter 6	Section 5.1 Sections 6.1.1, 6.3, 6.6	
1.2	Monitoring and continuously improving asset management practices;	2026 AMP	Chapter 6 Chapter 7 Chapter 18	Sections 6.1, 6.3-6.6 Section 7.1-7.3 Sections 18.1-18.2	
1.3	Close alignment with corporate vision and strategy;	2026 AMP	Chapter 6	Sections 6.1-6.3	
1.4	That asset management is driven by clearly defined strategies, business objectives and service level targets;	2026 AMP	Chapter 5 Chapter 6	Section 5.1 Section 6.1-6.3	
1.5	That responsibilities and accountabilities for asset management are clearly assigned;	2026 AMP	Chapter 6	Section 6.4	
1.6	An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets;	2026 AMP	Chapter 3 Chapter 8 Chapter 13 Chapter 14 Chapter 15	Sections 3.1 & 3.3 Section 8.4 Sections 13.1-13.5 Sections 14.1-14.9 Sections 15.1-15.5	
1.7	An emphasis on optimising asset utilisation and performance;	2026 AMP	Chapter 5 Chapter 10 Chapter 11 Chapter 12	Section 5.1 Sections 10.1-10.5 Sections 11.1-11.3 Section 12.1-12.7	

1.8	That a total life cycle approach should be taken to asset management;	2026 AMP	Chapter 6	Section 6.6	
1.9	That the use of **non-network solutions** and demand management techniques as alternatives to asset acquisition is considered.	2026 AMP	Chapter 6 Chapter 9 Chapter 10	Section 6.6.1.2 Sections 9.2-9.4 Sections 10.1, 10.3-10.4	
2.	The disclosure requirements are designed to produce **AMPs** that—				
2.1	Are based on, but are not limited to, the core elements of asset management identified in clause 1;				
2.2	Are clearly documented and made available to all stakeholders;				
2.3	Contain sufficient information to allow interested **persons** to make an informed judgement about the extent to which the **EDB's** asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets;				
2.4	Specifically support the achievement of disclosed service level targets;				
2.5	Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment;				
2.6	Consider the mechanics of delivery including resourcing;				
2.7	Consider the organisational structure and capability necessary to deliver the **AMP**;				
2.8	Consider the organisational and contractor competencies and any training requirements;				
2.9	Consider the systems, integration and information management necessary to deliver the plans;				

2.10	To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between **EDBs**; and				
2.11	Promote continual improvements to asset management practices.				
	*Disclosing an **AMP** does not constrain an **EDB** from managing its assets in a way that differs from the **AMP** if its circumstances change after preparing the plan or if the **EDB** adopts improved asset management practices.*				
Contents of the AMP					
3.	The **AMP** must include the following-	2026 AMP			
3.1	A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	2026 AMP	Chapter 1		Executive summary
3.2	Details of the background and objectives of the EDB's asset management and planning processes;	2026 AMP	Chapter 6	Sections 6.1-6.6	
3.3	A purpose statement which-	2026 AMP	Chapter 2	Section 2.2	
3.3.1	makes clear the purpose and status of the **AMP** in the **EDB's** asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes;				
3.3.2	states the corporate mission or vision as it relates to asset management;				
3.3.3	identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB**;				
3.3.4	states how the different documented plans relate to one another, - with particular reference to any plans specifically dealing with asset management; and				
3.3.5	includes a description of the interaction between the objectives of the **AMP** and other corporate goals, business planning processes, and plans;				

	*The purpose statement should be consistent with the **EDB's** vision and mission statements, and show a clear recognition of stakeholder interest.*				
3.4	Details of the **AMP planning period**, which must cover at least a projected period of 10 years commencing with the **disclosure year** following the date on which the **AMP** is disclosed; *Good asset management practice recognises the greater accuracy of short-to-medium term planning, and will allow for this in the **AMP**. The asset management planning information for the second 5 years of the **AMP planning period** need not be presented in the same detail as the first 5 years.*	2026 AMP	Chapter 2		Introductory paragraphs
3.5	The date that it was approved by the **directors**;	2026 AMP	Appendix H		Directors' Certificate (Sch 17)
3.6	A description of stakeholder interests (owners, **consumers** etc) which identifies important stakeholders and indicates-				
3.6.1	how the interests of stakeholders are identified	2026 AMP	Chapter 4	Sections 4.2-4.3	
3.6.2	what these interests are;	2026 AMP	Chapter 4	Sections 4.2 & 4.6	
3.6.3	how these interests are accommodated in asset management practices; and	2026 AMP	Chapter 4	Sections 4.7-4.8	
3.6.4	how conflicting interests are managed;	2026 AMP	Chapter 4	Sections 4.4.9	
3.7	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-				
3.7.1	governance—a description of the extent of **director** approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to **directors**;	2026 AMP	Chapter 6	Section 6.4	
3.7.2	executive—an indication of how the in-house asset management and planning organisation is structured; and	2026 AMP	Chapter 6	Section 6.4	
3.7.3	field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	2026 AMP	Chapter 6 Chapter 17	Section 6.4.2 Sections 17.1-17.3	

3.8	All significant assumptions-				
3.8.1	quantified where possible;	2026 AMP	Chapter 16	Section 16.6	
3.8.2	clearly identified in a manner that makes their significance understandable to interested **persons**, including-	2026 AMP	Chapter 16	Section 16.6	
3.8.3	a description of changes proposed where the information is not based on the **EDB's** existing business;	2026 AMP	Chapter 16	Section 16.6	Some of Orion's forecasts have external dependencies (e.g., population growth forecasts)
3.8.4	the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	2026 AMP	Chapter 16	Section 16.6	
3.8.5	the price inflator assumptions used to prepare the financial information disclosed in **nominal New Zealand dollars** in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b;	2026 AMP	Chapter 16	Section 16.3	
3.9	A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;	2026 AMP	Chapter 16	Sections 16.6-16.7	
3.10	An overview of asset management strategy and delivery; *To support the Report on Asset Management Maturity disclosure and assist interested* **persons** *to assess the maturity of asset management strategy and delivery, the* **AMP** *should identify-* • *how the asset management strategy is consistent with the* ***EDB's*** *other strategy and policies;* • *how the asset strategy takes into account the life cycle of the assets;* • *the link between the asset management strategy and the* ***AMP****; and* • *processes that ensure costs, risks and system performance will be effectively controlled when the* ***AMP*** *is implemented.*	2026 AMP	Chapter 6	Chapters 6.1-6.6	
3.11	An overview of systems and information management data;	2026 AMP			

3.11.1	To support the Report on Asset Management Maturity disclosure and assist interested **persons** to assess the maturity of systems and information management, the **AMP** should describe-	2026 AMP			
3.11.1(a)	the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;	2026 AMP	Chapter 8	Section 8.5.7	
3.11.1(b)	the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;	2026 AMP	Chapter 8	Section 8.5.7	
3.11.1(c)	the systems and controls to ensure the quality and accuracy of asset management information;	2026 AMP	Chapter 8	Sections 8.5.7.3 & 8.5.9	
3.11.1(d)	the extent to which these systems, processes and controls are integrated;	2026 AMP	Chapter 8	Section 8.5.7.4	
3.11.1(e)	how asset management data informs the models that an EDB develops and uses to assess asset health; and	2026 AMP	Chapter 14	Section 14.2-14.9	
3.11.1(f)	how the outputs of these models are used in developing capital expenditure projections.	2026 AMP	Chapter 14	Section 14.2	
3.12	A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data; *Discussion of the limitations of asset management data is intended to enhance the transparency of the* ***AMP*** *and identify gaps in the asset management system.*	2026 AMP	Chapter 8 Chapter 16	Section 8.6.6 Section 16.6	
3.13	A description of the processes used within the **EDB** for-				
3.13.1	managing routine asset inspections and **network** maintenance;	2026 AMP	Chapter 13	Sections 13.1-13.3	
3.13.2	planning and implementing **network** development projects; and	2026 AMP	Chapter 10	Sections 10.1-10.5	
3.13.3	measuring **network** performance;	2026 AMP	Chapter 5	Section 5.1	
3.14	An overview of asset management documentation, controls and review processes.	2026 AMP	Chapter 6	Section 6.1-6.6	

	*To support the Report on Asset Management Maturity disclosure and assist interested **persons** to assess the maturity of asset management documentation, controls and review processes, the **AMP** should-* *(i) identify the documentation that describes the key components of the asset management system and the links between the key components;* *(ii) describe the processes developed around documentation, control and review of key components of the asset management system;* *(iii) where the **EDB** outsources components of the asset management system, the processes and controls that the **EDB** uses to ensure efficient and cost effective delivery of its asset management strategy;* *(iv) where the **EDB** outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and* *(v) audit or review procedures undertaken in respect of the asset management system.*				
3.15	An overview of communication and participation processes; *To support the Report on Asset Management Maturity disclosure and assist interested **persons** to assess the maturity of asset management documentation, controls and review processes, the **AMP** should-* (i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and (ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.	2026 AMP	Chapter 6	Section 6.5	
3.16	The **AMP** must present all financial values in **constant price** New Zealand dollars except where specified otherwise; and	2026 AMP	Throughout		
3.17	The **AMP** must be structured and presented in a way that the **EDB** considers will support the purposes of **AMP** disclosure set out in clause 2.6.2 of the determination.	2026 AMP	Throughout		
Assets covered					

4.	The **AMP** must provide details of the assets covered and **non-network solutions**, including-				
4.1	a high-level description of the service areas covered by the **EDB** and the degree to which these are interlinked, including-				
4.1.1	the region(s) covered	2026 AMP	Chapter 3	Section 3.1	
4.1.2	identification of large **consumers** that have a significant impact on **network** operations or asset management priorities;	2026 AMP	Chapter 3	Section 3.3.4	
4.1.3	description of the load characteristics for different parts of the **network**;	2026 AMP	Chapter 11	Section 11.2	
4.1.4	peak demand and total energy delivered in the previous year, broken down by **sub-network**, if any.	2026 AMP	Chapter 3 Chapter 11	Section 3.3 Section 11.2	
4.2	a description of the **network** configuration, including				
4.2.1	identifying bulk electricity supply points and any **distributed generation** with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	2026 AMP	Chapter 3 Chapter 11	Section 3.3 Section 11.2.1	
4.2.2	a description of the **subtransmission** system fed from the bulk electricity supply points, including the capacity of **zone substations** and the voltage(s) of the **subtransmission network**(s). The **AMP** must identify the supply security provided at individual **zone substations**, by describing the extent to which each has n-x **subtransmission** security or by providing alternative security class ratings;	2026 AMP	Chapter 3 Chapter 11 Appendix B	Section 3.3.1 Section 11.2 Schedule 12b	
4.2.3	a description of the distribution system, including the extent to which it is underground;	2026 AMP	Chapter 11 Chapter 12 Chapter 14	Section 11.2.3 Section 12.3 Section 14.4.2 Section 14.5.2	
4.2.4	a brief description of the network's **distribution** substation arrangements;	2026 AMP	Chapter 14	Sections 14.7.4 & 14.8	

4.2.5	a description of the **low voltage network** including the extent to which it is underground;	2026 AMP	Chapter 11 Chapter 12 Chapter 14	Section 11.2.4 Section 12.4 Section 14.4.3 Section 14.5.3	
4.2.6	an overview of **secondary assets** such as protection relays, ripple injection systems, SCADA and telecommunications systems; and	2026 AMP	Chapter 14	Section 14.9	
4.2.7	a quantification of the contribution each **non-network solution** makes towards solving a **network** risk or constraint, and a description of the extent to which those **non-network solutions** are provided by a **related party** or third party. *To help clarify the **network** descriptions, **network** maps and a single line diagram of the **subtransmission network** should be made available to interested **persons**. These may be provided in the **AMP** or, alternatively, made available upon request with a statement to this effect made in the **AMP**.*	2026 AMP	Chapter 10 Chapter 12 Appendix B Appendix D	Section 10.4.6 Sections 12.1, 12.3-12.4 Schedule 11b	Non-network solutions are factored into a number of projects, but cannot be quantified with certainty and remain subject to market availability. All are expected to be procured from 3rd-party providers.
4.3	If **sub-networks** exist, the **network** configuration information referred to in clause 4.2 must be disclosed for each **sub-network**.				N/A - Orion does not have subnetworks
Network assets by category					
4.4	The **AMP** must describe the **network** assets by providing the following information for each asset category-	2026 AMP	Chapter 14	Sections 14.1-14.10	
4.4.1	voltage levels;				
4.4.2	description and quantity of assets;				
4.4.3	age profiles; and				
4.4.4	a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.				
4.5	The asset categories discussed in clause 4.4 should include at least the following-				

4.5.1	the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	2026 AMP	Chapter 14	Sections 14.1-14.10	
4.5.2	assets owned by the **EDB** but installed at bulk electricity supply points owned by others;	2026 AMP	Chapter 14	Section 14.9.6	
4.5.3	**EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	2026 AMP	Chapter 14	Section 14.8.4	
4.5.4	other generation plant owned by the **EDB**.	2026 AMP	Chapter 14	Section 14.8.4	
Service levels					
5.	The **AMP** must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the **AMP planning period**. The targets should reflect what is practically achievable given the current **network** configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the **AMP planning period**.	2026 AMP	Chapter 5	Section 5.1	
6.	Performance indicators for which targets have been defined in clause 5 must include **SAIDI values** and **SAIFI values** for the next 5 **disclosure years**.	2026 AMP	Chapter 5	Section 5.1.3.	
7.	Performance indicators for which targets have been defined in clause 5 should also include-				
7.1	**Consumer** oriented indicators that preferably differentiate between different consumer types; and	2026 AMP	Chapter 5	Section 5.1.3-5.1.4, 5.1.6-5.1.8, 5.2	
7.2	Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	2026 AMP	Chapter 5	Sections 5.1.3 & 5.1.5	
8.	The **AMP** must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes **consumer** expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The **AMP** should demonstrate how stakeholder needs were ascertained and translated into service level targets.	2026 AMP	Chapter 5	Section 5.1	

9.	Targets should be compared to historic values where available to provide context and scale to the reader.	2026 AMP	Chapter 5	Section 5.1.1	
10.	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance. *Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent **AMP***	2026 AMP	Chapter 5	Section 5.1	A number of service levels are new, aligning to current investment priorities.
Network Development Planning					
11.	**AMPs** must provide a detailed description of network development plans, including-				
11.1	A description of the planning criteria and assumptions for **network** development;	2026 AMP	Chapter 10	Sections 10.2.2.3, 10.2.3.2, 10.3.1 & 10.4	
11.2	Planning criteria for **network** developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	2026 AMP	Chapter 10	Sections 10.1-10.3	
11.3	A description of strategies or processes (if any) used by the **EDB** that promote cost efficiency including through the use of standardised assets and designs;	2026 AMP	Chapter 6 Chapter 16	Section 6.6.1.3 Section 16.5	
11.4	The use of standardised designs may lead to improved cost efficiencies. This section should discuss-				
11.4.1	the categories of assets and designs that are standardised; and	2026 AMP	Chapter 6	Section 6.6.1.3	
11.4.2	the approach used to identify standard designs;	2026 AMP	Chapter 6	Section 6.6.1.3	
11.5	A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**; *The energy efficient operation of the **network** could be promoted, for example, though **network** design strategies, demand side management strategies and asset purchasing strategies.*	2026 AMP	Chapter 9	Sections 9.1-9.4	
11.6	A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the **network**;	2026 AMP	Chapter 10	Sections 10.3.1 & 10.4	

	*The criteria described should relate to the **EDB's** philosophy in managing planning risks.*				
11.7	A description of the process and criteria used to prioritise **network** development projects and how these processes and criteria align with the overall corporate goals and vision;	2026 AMP	Chapter 16	Section 16.8	
11.8	Details of demand forecasts, the basis on which they are derived, and the specific **network** locations where constraints are expected due to forecast increases in demand;				
11.8.1	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	2026 AMP	Chapter 10 Chapter 11	Section 10.2 Section 11.1-11.3	
11.8.2	provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	2026 AMP	Chapter 10 Chapter 11	Section 10.2 Sections 11.1-11.3	
11.8.3	identify any **network** or equipment constraints that may arise due to the anticipated growth in demand during the **AMP planning period**; and	2026 AMP	Chapter 11 Chapter 12	Sections 11.2-11.3 Sections 12.1-12.4	
11.8.4	discuss the impact on the load forecasts of any anticipated levels of **non-network solutions** in a **network**;	2026 AMP	Chapter 10 Chapter 12 Appendix D	Sections 10.2-10.4 Sections 12.1, 12.3-12.4	
11.9	Analysis of the significant **network** level development options identified and details of the decisions made to satisfy and meet target levels of service, including-				
11.9.1	the reasons for choosing a selected option for projects where decisions have been made;	2026 AMP	Appendix D		
11.9.2	the alternative options considered for projects that are planned to start in the next five years and the potential for **non-network solutions** described; and	2026 AMP	Appendix D		

11.9.3	consideration of planned innovations that improve efficiencies within the **network**, such as improved utilisation, extended asset lives, and deferred investment;	2026 AMP	Chapter 9 Chapter 16	Sections 9.1-9.5 Section 16.5	
11.10	A description and identification of the network development programme including **non-network solutions** and actions to be taken, including associated expenditure projections. The **network** development plan must include-				
11.10.1	a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	2026 AMP	Chapter 12 Appendix D	Sections 12.1-12.7	
11.10.2	a summary description of the programmes and projects planned for the following four years (where known); and	2026 AMP	Chapter 12 Appendix D	Sections 12.1-12.7	
11.10.3	an overview of the material projects being considered for the remainder of the **AMP planning period**; *For projects included in the **AMP** where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including a detailed description of the investigations undertaken in respect of the potential for **non-network solutions** to be more cost effective than **network** augmentations and vice versa. This should specify if any third parties were approached in relation to **non-network solutions**, and if so, whether those third parties are **related parties**. For the purposes of disclosing the information described in clause 11.10.3, an **EDB** is not required to include commercially sensitive or confidential information.*	2026 AMP	Chapter 12 Appendix D	Sections 12.1-12.2	
11.11	A description of the **EDB's** policies on **distributed generation**, including the policies for connecting **distributed generation**. The impact of such generation on network development plans must also be stated; and	2026 AMP	Chapter 10	Sections 10.4, 10.5.4.2	Web link to published DG policies and on-line application forms available in this section
11.12	A description of the EDB's policies on non-network solutions, including-				

11.12.1	economically feasible and practical alternatives to conventional **network** augmentation. These are typically approaches that would reduce **network** demand and/or improve asset utilisation;	2026 AMP	Chapter 9 Chapter 10	Section 9.4 Section 10.4	
11.12.2	the potential for **non-network solutions** to address **network** problems or constraints; and	2026 AMP	Chapter 9 Chapter 10 Chapter 11 Chapter 12	Section 9.4 Section 10.4 Sections 11.2 Sections 12.3-12.4	
11.12.3	how information on current and forecast constraints (both load and injection) is shared with potential providers of **non-network solutions**. This must include any information on **low voltage network** constraints, including the constraint information the **EDB** derives from the data specified under clause 17.2.2 of Attachment A.	2026 AMP	Chapter 10	Section 10.4.6	
Lifecycle Asset Management Planning (Maintenance and Renewal)					
12.	The AMP must provide a detailed description of the lifecycle asset management processes, including-				
12.1	The key drivers for maintenance planning and assumptions;	2026 AMP	Chapter 13 Chapter 14 Chapter 16	Sections 13.1, 13.2.2, 13.3.2, 13.4.2, 13.5.2 Sections 14.2-14.9 Section 16.6	
12.2	Identification of **routine and corrective maintenance and inspection** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-				
12.2.1	the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	2026 AMP	Chapter 13 Appendix G	Sections 13.1-13.3	
12.2.2	any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	2026 AMP	Chapter 14	Sections 14.3-14.9	Each relevant sub-section contains a table detailing asset risks and mitigations where type issues (if any) are noted.

12.2.3	budgets for maintenance activities broken down by asset category for the **AMP planning period**;	2026 AMP	Appendix G	Section G1	
12.3	Identification of **asset replacement and renewal** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-				
12.3.1	the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the **network** and the optimum use of existing **network** assets;	2026 AMP	Chapter 6 Chapter 10 Chapter 14	Section 6.6.4 Section 10.3.3 Section 14.2	
12.3.2	a description of innovations that have deferred asset replacements;	2026 AMP	Chapter 6	Section 6.6.4.1	
12.3.3	a description of the projects currently underway or planned for the next 12 months;	2026 AMP	Appendix E		
12.3.4	a summary of the projects planned for the following four years (where known); and	2026 AMP	Appendix E		
12.3.5	an overview of other work being considered for the remainder of the **AMP** planning period; and	2026 AMP	Chapter 14 Appendix E	Sections 14.3-14.9	
12.4	The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	2026 AMP	Chapter 14	Section 14.2.3	Orion performs some additional disaggregation; however the categories described in clause 4.5 are addressed.
12.5	Identification of the approach used for developing **capital expenditure** projections for lifecycle asset management. This must include an explanation of:	2026 AMP	Chapter 6 Chapter 14	Section 6.6.1.4 Sections 14.2-14.9	
12.5.1	the approach that the **EDB** uses to inform its **capital expenditure** projections for lifecycle asset management; and				
12.5.2	the rationale for using the approach for each asset category.				
12.6	Identification of **vegetation management** related maintenance. This must include an explanation of the approach and assumptions that the **EDB** uses to inform its **vegetation management** related maintenance.	2026 AMP	Chapter 13 Chapter 16	Section 13.5 Section 16.6	

12.7	The **EDB's** consideration of **non-network solutions** to inform its **capital and operational expenditure** projections for lifecycle asset management. This must include an explanation of the approach and assumptions the **EDB** used to inform these expenditure projections;	2026 AMP	Chapter 6	Section 6.6.1.2	
Non-Network Development, Maintenance and Renewal					
13.	**AMPs** must provide a summary description of material non-network development, maintenance and renewal plans, including-				
13.1	a description of **non-network assets**;	2026 AMP	Chapter 8 Chapter 15	Sections 8.4-8.6 Section 15.2	
13.2	development, maintenance and renewal policies that cover them;	2026 AMP	Chapter 8 Chapter 15	Sections 8.4-8.6 Sections 15.3, 15.4	
13.3	a description of material **capital expenditure** projects (where known) planned for the next five years; and	2026 AMP	Chapter 8 Chapter 15	Section 8.4 Sections 15.3-15.5	
13.4	a description of material maintenance and renewal projects (where known) planned for the next five years.	2026 AMP	Chapter 8 Chapter 15	Section 8.4 Sections 15.3-15.5	
Risk Management					
14.	**AMPs** must provide details of risk policies, assessment, and mitigation, including-				
14.1	Methods, details and conclusions of risk analysis;	2026 AMP	Chapter 7	Section 7.1	
14.2	Strategies used to identify areas of the **network** that are vulnerable to high impact low probability events and a description of the resilience of the **network** and asset management systems to such events;	2026 AMP	Chapter 7	Section 7.4	
14.3	A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	2026 AMP	Chapter 7	Section 7.1 & 7.4	
14.4	Details of emergency response and contingency plans.	2026 AMP	Chapter 7	Section 7.4	

	*Asset risk management forms a component of an **EDB's** overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. **AMPs** should demonstrate how the **EDB** identifies and assesses asset related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.*				
Evaluation of performance					
15.	**AMPs** must provide details of performance measurement, evaluation, and improvement, including-				
15.1	A review of progress against plan, both physical and financial; • *referring to the most recent disclosures made under clause 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances;* • *commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced; and* • *commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.*	2026 AMP	Chater 16	Section 16.1	
15.2	An evaluation and comparison of actual service level performance against targeted performance; • *in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the **AMP** in the previous **AMP** and explain any significant variances.*	2026 AMP	Chapter 5	Section 5.1	
15.3	An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the **EDB's** asset management and planning processes.	2026 AMP	Chapter 18	Section 18.1	

15.4	An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the **AMP** must describe any planned initiatives to address the situation.	2026 AMP	Chapter 18	Section 18.2	
Capability to deliver					
16.	**AMPs** must describe the processes used by the EDB to ensure that-				
16.1	The **AMP** is realistic and the objectives set out in the plan can be achieved; and	2026 AMP	Chapter 17	Sections 17.1-17.2	
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the **AMP**.	2026 AMP	Chapter 6	Section 6.4	
Requirements to provide qualitative information in narrative form					
17.	**AMPs** must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:				
Notice of planned and unplanned interruptions					
17.1	a description of how the **EDB** provides notice to and communicates with **consumers** regarding **planned interruptions** and **unplanned interruptions**, including any changes to the **EDB's** processes and communications in respect of **planned interruptions** and **unplanned interruptions**;	2026 AMP	Chapter 5	Section 5.2.1	
Voltage quality and constraints					
17.2	a description of the **EDB's** practices for:				
17.2.1	monitoring voltage, including:				
17.2.1(a)	the **EDB's** practices for monitoring voltage quality on its **low voltage network**;	2026 AMP	Chapter 9 Chapter 5	Section 9.3.1 Section 5.1.4	
17.2.1(b)	work the **EDB** is doing on its **low voltage network** to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010;	2026 AMP	Chapter 5 Chapter 9 Chapter 12	Section 5.1.4 Section 9.3.1 Section 12.4	
17.2.1(c)	how the **EDB** responds to and reports on voltage quality issues when the **EDB** identifies them, or when they are raised by a stakeholder;	2026 AMP	Chapter 9 Chapter 5	Section 9.3.1 Sections 5.1.4, 5.2.2	

17.2.1(d)	how the **EDB** communicates with affected **consumers** regarding the voltage quality work it is carrying out on its **low voltage network**; and	2026 AMP	Chapter 4 Chapter 5	Section 4.5 Sections 5.1.4, 5.2.2	
17.2.1(e)	any plans for improvements to any of the practices outlined at clauses (a)-(d) above;	2026 AMP	Chapter 5 Chapter 9	Section 5.1.4 Section 9.3.1	
17.2.2	monitoring load and injection constraints, including:				
17.2.2(a)	any challenges, and progress, towards collecting or procuring data required to inform the **EDB** of current and forecast constraints on its **low voltage network**, including historical consumption data; and	2026 AMP	Chapter 9	Section 9.3	
17.2.2(b)	any analysis and modelling (including any assumptions and limitations) the **EDB** undertakes, or intends to undertake, with the data described in clause 17.2.2(a).	2026 AMP	Chapter 9	Section 9.3	
Customer service practices					
	There may be a degree of overlap between the information required under this clause and the information required in respect of customer charters under clause 2.5.3. For the avoidance of doubt, if there is overlap, EDBs should disclose the information in both places.				
17.3	a description of the **EDB's** customer service practices, including:				
17.3.1	the **EDB's** customer engagement protocols and customer service measures – including customer satisfaction with the **EDB's** supply of **electricity distribution services**;	2026 AMP	Chapter 4	Sections 4.1-4.8	
17.3.2	the **EDB's** approach to planning and managing customer **complaint** resolution;	2026 AMP	Chapter 5	Section 5.2	
Practices for connecting new consumers and altering existing connections					
17.4	a description of the **EDB's** practices for connecting **consumers**, including	2026 AMP	Chapter 10	Section 10.5	
17.4.1	the **EDB's** approach to planning and management of-				
17.4.1(a)	connecting new **consumers** (offtake and injection connections), and overcoming commonly encountered issues; and				
17.4.1(b)	alterations to existing connections (offtake and injection connections);				

17.4.2	how the **EDB** is seeking to minimise the cost to **consumers** of new or altered connections;				
17.4.3	the **EDB's** approach to planning and managing communication with **consumers** about new or altered connections;				
17.4.4	commonly encountered delays and potential timeframes for different connections; and				
17.4.5	the **EDB's** approach to sharing information on current and forecast constraints (both load and injection) with potential new **consumers**. This must include any information on **low voltage network** constraints, including the constraint information the **EDB** derives from the data specified under clause 17.2.2(a) of Attachment A.				
New connections likely to have a significant impact on network operations or asset management priorities					
	*The following requirements focus on the **EDB's** capability and risk management regarding demand, generation, or storage capacity that the **EDB** considers are likely to have a significant impact on its network operations or asset management priorities. The **EDB** may consider voltage, network location, or other factors in making this assessment.*	2026 AMP	Chapter 10 Chapter 11	10.1-10.5 11.1-11.3	
17.5	A description of the following:				
17.5.1	how the **EDB** assesses the impact that new demand, generation, or storage capacity will have on the **EDB's network**, including:				
17.5.1(a)	how the **EDB** measures the scale and impact of new demand, generation, or storage capacity;				
17.5.1(b)	how the **EDB** takes the timing and uncertainty of new demand, generation, or storage capacity into account;				
17.5.1(c)	how the **EDB** takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and				
17.5.2	how the **EDB** assesses and manages the risk to the **network** posed by uncertainty regarding new demand, generation, or storage capacity;				

Innovation practices					
17.6 17.6.1 17.6.2 17.6.3 17.6.4 17.6.5	a description of the following: any **innovation practices** the **EDB** has planned or undertaken since the last **AMP** or **AMP update** was **publicly disclosed**, including case studies and trials; the **EDB's** desired outcomes of any **innovation practices**, and how they may improve outcomes for **consumers**; how the **EDB** measures success and makes decisions regarding any **innovation practices**, including how the **EDB** decides whether to commence, commercially adopt, or discontinue these practices; how the **EDB's** decision-making and **innovation practices** depend on the work of other companies, including other EDBs and providers of **non-network solutions**; and the types of information the **EDB** uses to inform or enable any **innovation practices**, and the **EDB's** approach to seeking that information.	2026 AMP	Chapter 6 Chapter 9	Section 6.3.1 Section 9.5	
17.7	For the purpose of disclosing the information required under clauses 17.6.1- 17.6.5 above, an **EDB** is not required to include commercially sensitive or confidential information.				

Appendix D – Major system growth projects portfolio

This appendix provides detailed information on our major system growth projects portfolio planned during the AMP period. Where non-network solutions are selected following investment decisions, associated operating expenditure and pricing details are released on our flexibility opportunities webpage.

Table D.1 Orion's major system growth projects portfolio ($m, FY26 constant)

Project	Investment need	Shortlist options	Identified solution and benefits	From	To	Capex
Lincoln Township growth	Capacity limitations at Lincoln zone substation with undersized, aged primary assets on space-constrained site. Substation firm capacity breached over several winter days. Peak demand forecast to increase 30% over next decade driven by large mixed-use subdivisions, such as the 2,000 residential dwellings at Earlsbrook. Risk of cascade blackout outage increases as aging transformers operate beyond firm capacity. Township fringe spreading makes existing substation location suboptimal for serving growth.	**Option 1**: Do nothing. Constraint leads to load shedding and inability to connect new load. Does not meet security criteria or customer needs. **Option 4**: Install 3 3kV Greenpark substation on eastern fringe to increase capacity and fully replace Lincoln ZS. Utilises 33 kV subtransmission network. **Option 6**: Same as Option 4 but with 66kV supply. Requires 33 kV system bypass to maintain supply. **Option 8**: Same as Option 4 with non-network flexibility solution deferring network investment by one year.	**Selected Option 8**: Establish new 33 kV Greenpark zone substation (23MVA) on eastern fringe of Lincoln township to increase capacity and fully replace Lincoln zone substation, supplemented by non-network solution enabling one-year deferment (FY28 to FY29). This solution addresses both capacity and asset renewal issues, provides highest net benefit while derisking timing sensitivity through supplementary non-network solution. Location supports long-term Network Development Strategy transition from 33 kV to 66 kV. Solution enables forecast 30% demand growth including Earlsbrook subdivision and transport electrification. **Benefits include**: maintaining current reliability levels for Lincoln township; enabling regional growth and electrification; retiring aging transformers reducing failure probability; providing adequate 20-year capacity; and incorporating cost-effective flexibility services demonstrating integrated planning.	FY28	FY30	13.9

Lincoln township growth

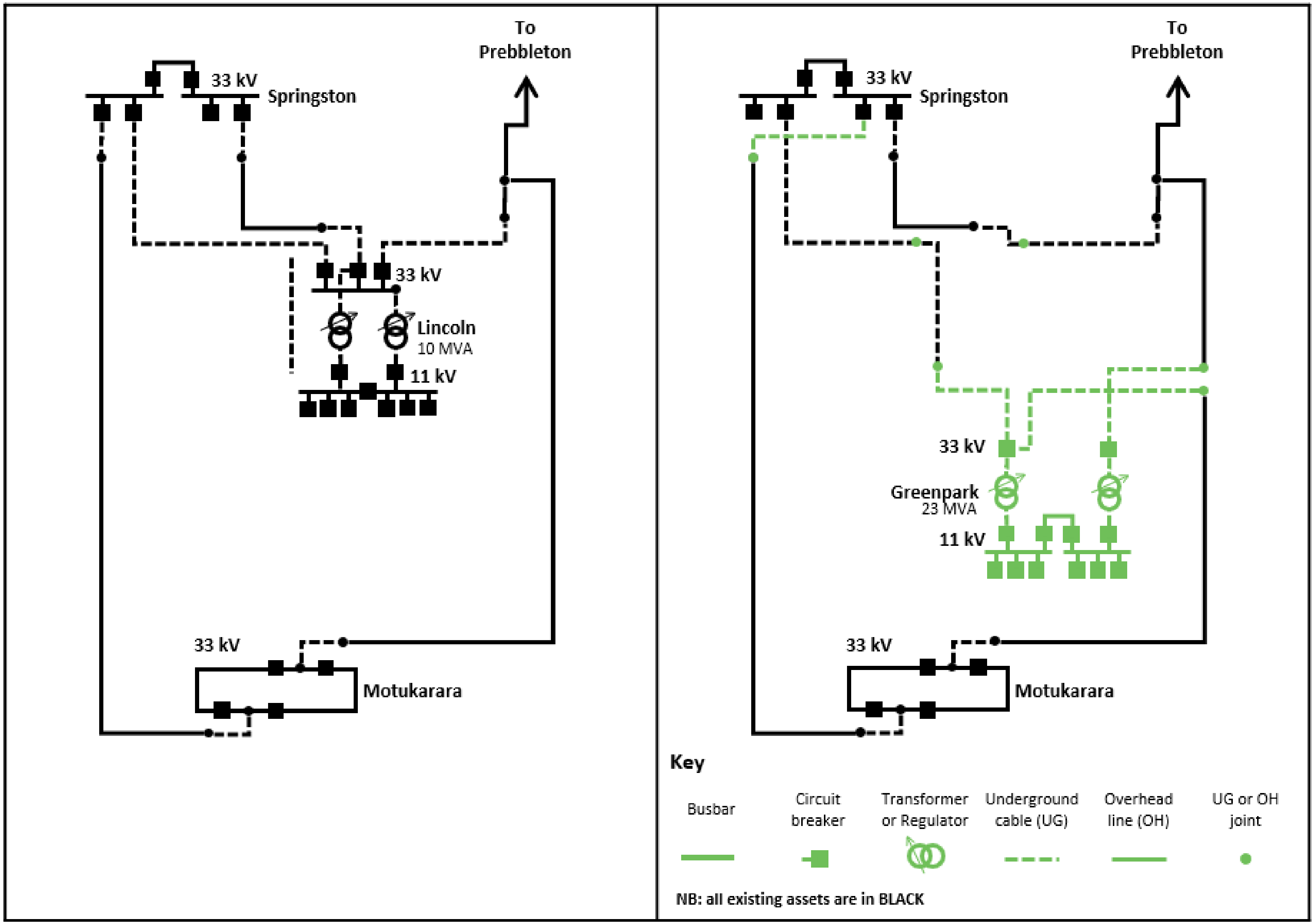

Table D.1 Orion's major system growth projects portfolio ($m, FY26 constant)

Project	Investment need	Shortlist options	Identified solution and benefits	From	To	Capex
Templeton commercial growth	Department of Corrections facilities (Christchurch Men's and Women's Prisons (CMP and CWP)) and proposed new vertical farm are supplied by a lengthy, sparse 11 kV overhead feeder (CB115) from Moffett St zone substation. Feeder extends 9km with few interconnections and experiences significantly higher fault rate than expected (10 faults/year vs 5.7 expected). CMP and CWP intend to decarbonise heating demand and expand facilities, with proposed vertical farm also connecting to same feeder. Combined new demand will breach Moffett St zone substation firm capacity by FY33 (brought forward from FY36). Existing 11 kV feeder has insufficient capacity for increased demand and inadequate reliability for critical facilities.	**Option 1**: Do nothing. Does not enable CMP/CWP electrification or proposed vertical farm connection. **Option 2**: 11 kV network reinforcement. Addresses capacity but not reliability concerns on sparse feeder. **Option 4**: Single 66 kV tee-off substation with one 23 MVA transformer. Lower cost but less network flexibility. **Option 5**: Two bay 66 kV substation with one 23 MVA transformer and in-and-out connection into Islington GXP - Weedons zone substation 66 kV line. Provides better reliability and network benefits. **Option 6**: Same as Option 5 with supplementary non-network flexibility solution.	**Selected Option 5**: Construct new 66/11 kV single 23 MVA transformer rated substation with in-and-out connection into Islington GXP - Weedons zone substation 66 kV line. New substation provides capacity direct to customer premises, removing demand from sparse 11 kV feeder with superior reliability being only susceptible to low probability events (transformer or busbar faults). Has wider network benefits beyond directly supplying nominal customers including ability to support adjacent substations under outage and enable capacity management. Department of Corrections owns significant adjacent land holdings streamlining potential site acquisition. Although the selected option is a full capex solution we will work with the Department of Corrections prior to determine whether a non-network solution that incorporates solar photovoltaics and battery energy storage system could be used as a more cost efficient alternative. **Benefits include**: enabling CMP/CWP decarbonisation removing barrier to sustainability goals; providing significantly improved reliability for critical facilities; supporting new vertical farm development; creating broader network benefits for adjacent substations; and balancing risk, reliability and affordability through staged approach.	FY29	FY31	11.2

Templeton commercial growth

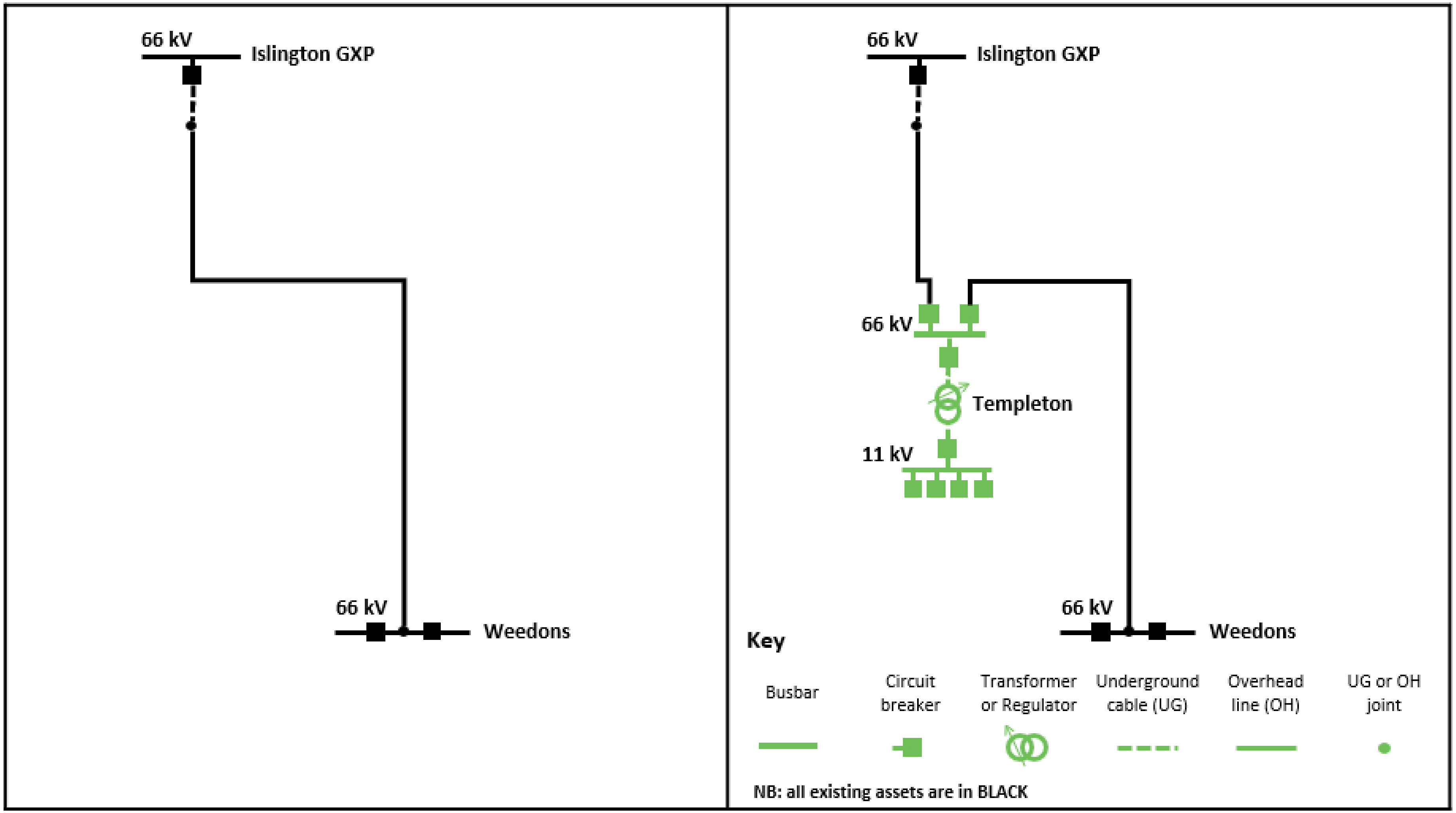

Table D.1 Orion's major system growth projects portfolio ($m, FY26 constant)

Project	Investment need	Shortlist options	Identified solution and benefits	From	To	Capex
Lyttelton Port Company Growth	Capacity limitations of supply to Lyttelton suburb and Lyttelton Port Company (LPC). LPC is a lifelines provider with forecast demand growth of +20 MW over next 20 years driven by port expansion and shore-to-ship electrification. Current firm capacity will be breached by FY31 (brought forward from FY46 without LPC growth). The Heathcote zone substation – Lyttelton 11 kV network has no resupply options once firm capacity is breached due to geographic isolation created by Port Hills.	**Option 1**: Do nothing. Constraint leads to load shedding and inability to connect new load. Does not meet security criteria, or customer needs. **Option 3**: Install fourth 11 kV circuit from Heathcote zone substation to Lyttelton plus reinforce one existing circuit. Utilises second cable allocation in Lyttelton road tunnel from 2019 installation. Upgrades available capacity to meet 20-year forecast. **Option 7**: Same as Option 3 but with non-network flexibility solution deferring network investment by one year.	**Selected Option 7**: Install fourth 11 kV circuit utilising existing tunnel infrastructure plus reinforcement of one circuit, with non-network flexibility solution deferring investment by one year (FY29 to FY30). This solution provides adequate capacity for 20-year forecast, leverages existing tunnel investment, incorporates cost-effective non-network solution demonstrating integrated planning approach, and maintains security of supply to lifelines provider. **Benefits include**: enabling LPC decarbonisation strategy; maintaining security of supply to both the Lyttelton area and to a critical lifelines provider; supporting regional economic development; demonstrating integration of flexibility services; and incorporating cost-effective flexibility services demonstrating integrated planning.	FY30	FY32	9.1

Lyttelton Port Company (LPC) growth

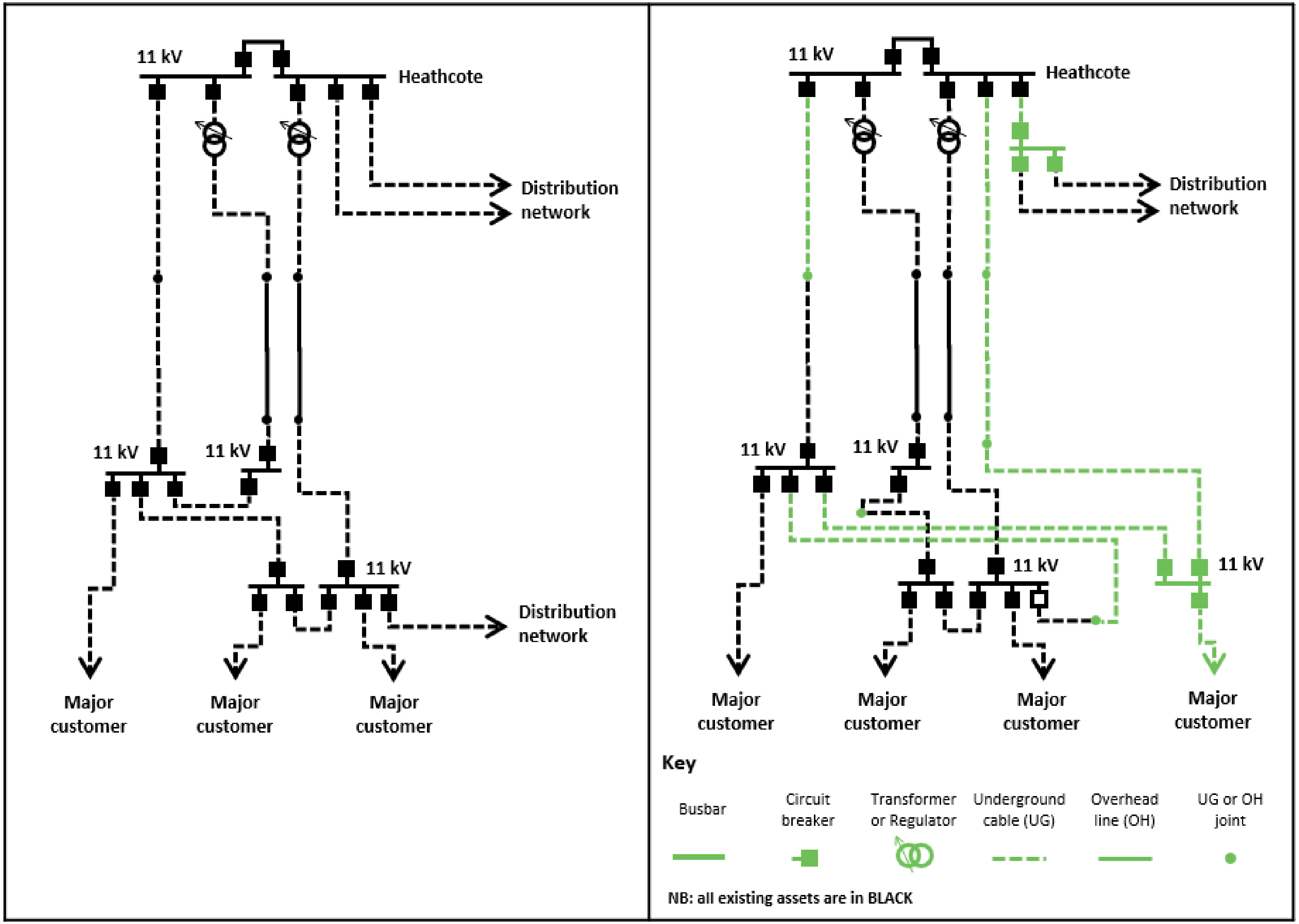

Table D.1 Orion's major system growth projects portfolio ($m, FY26 constant)

Project	Investment need	Shortlist options	Identified solution and benefits	From	To	Capex
Lower Selwyn growth – Stage 1	Emerging capacity and security of supply constraints around areas supplied by Killinchy, Brookside and Hills Road zone substations. All three sites have single power transformers requiring customer flexibility services (irrigation interruptibility) to restore power following summer outages. Long network distances already driven voltage support installation. Issues compounded if ANZCO (south of Killinchy zone substation) decarbonises as per North Canterbury Regional Energy Transition Accelerator report. Current 10MVA capacity limit at Killinchy restricts growth and makes contingency plans increasingly difficult.	**Option 1**: Do nothing. Continues reliance on irrigation interruptibility for contingency restoration. Limits growth potential and increases vulnerability. **Option 3**: Install second 10 MVA power transformer at Killinchy zone substation plus associated switchgear. Allows peak demand to exceed 10 MVA and simplifies contingency plans across three zone substations. **Option 6**: Same as Option 3 but with non-network flexibility solution deferring network investment by up to two years.	**Selected Option 6**: Install second 10 MVA transformer at Killinchy zone substation along with associated switchgear. Installation can potentially be deferred up to two years by procuring non-network solution. This solution provides highest NPV of all options meeting the investment need. Tactical upgrade makes contingency plans for Killinchy, Brookside and Hills Road significantly easier. Relatively low-cost solution in context of future substation requirements in area. Killinchy was originally designed to be upgradable to dual transformer site. Scope may expand to include 66 kV/11 kV switchgear replacement if appropriate at construction time. **Benefits include**: maintaining security of supply across three single-transformer substations; enabling potential ANZCO decarbonisation supporting regional sustainability goals; reducing reliance on irrigation interruptibility for contingency restoration; providing capacity for continued area growth; and two-year capex deferral reducing NPV impact.	FY33	FY35	3.6

Lower Selwyn growth – Stage 1

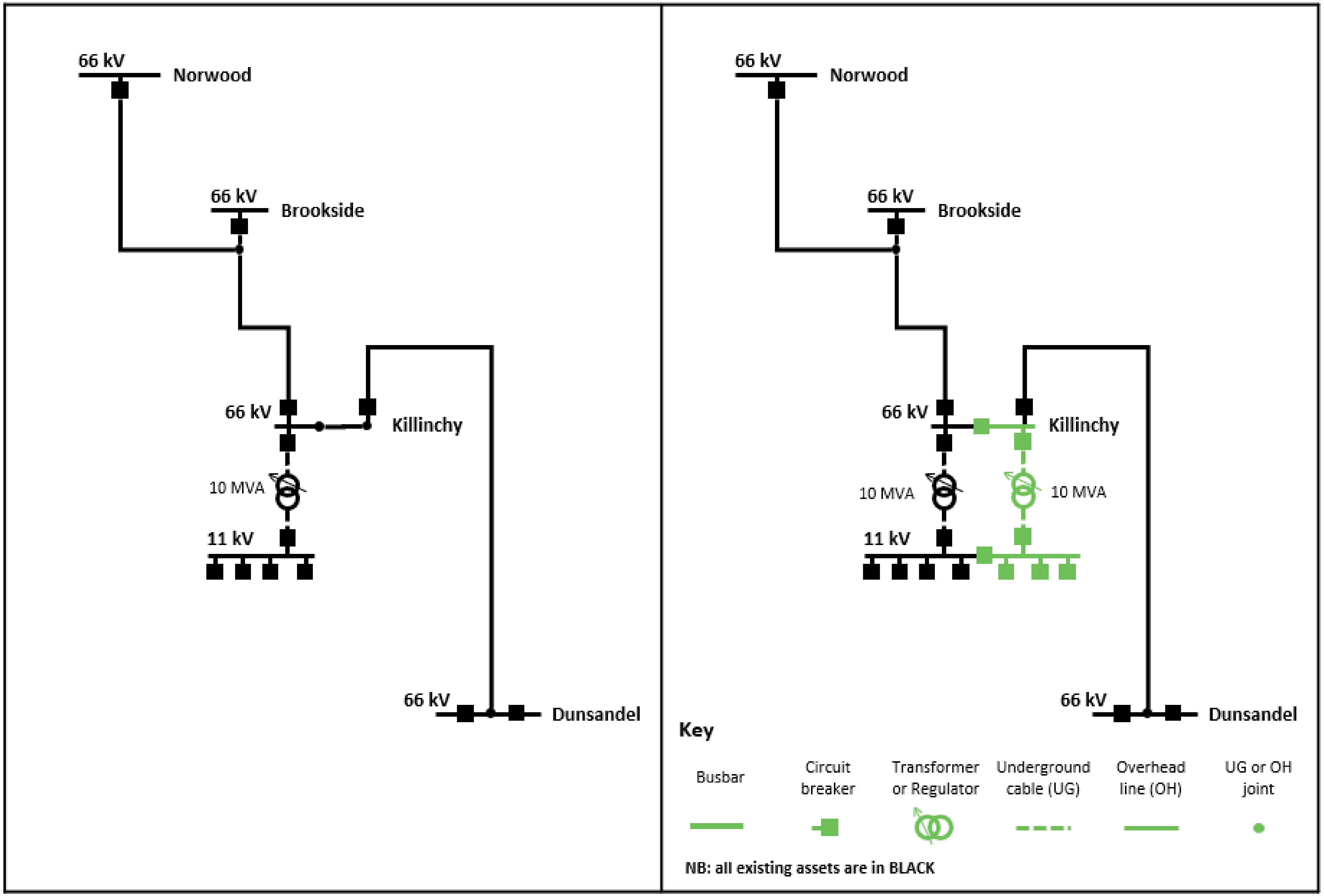

Table D.1 Orion's major system growth projects portfolio ($m, FY26 constant)

Project	Investment need	Shortlist options	Identified solution and benefits	From	To	Capex
Malvern industrial growth	An abattoir in Malvern is proposing a 3.7 MW staged upgrade to its operation between CY26 and CY29. This additional demand will breach Highfield zone substation firm capacity by FY28 (FY33 on base forecast) and will cause excessive voltage drop on the 11 kV overhead conductor supplying the abattoir. Without investment, connection of this load growth cannot proceed and voltage quality will not meet regulatory requirements.	**Option 1**: Do nothing. Stop connecting new load when firm capacity exceeded. Does not meet security criteria or enable customer growth. **Option 2**: Establish 66/11 kV at Norwood ZS. Liven existing transformer on pad, install switchgear. Supplies abattoir from Norwood (4km away) instead of Highfield (9km away). **Option 3**: Upgrade Highfield ZS to 23MVA. Replace transformer, install 9km cable feeder to address voltage drop. **Option 4**: Establish new ZS at abattoir site. Build entire 66/11 kV substation adjacent to load with new 66 kV overhead circuit connection.	**Selected Option 2**: Establish 66/11 kV supply at Norwood zone substation by installing switchgear and livening existing 10 MVA transformer already on pad. Leverages existing infrastructure, as Norwood was designed as upgradable dual-transformer site supporting future growth. This also shortens distribution network from 9 km to 4 km, reducing voltage drop and requiring minimal 11 kV reinforcement. Allows part of Highfield load to shift to new supply point, providing headroom for both committed industrial expansion and continued organic growth in the area. **Benefits include**: enabling abattoir growth plans supporting regional industrial development, meeting Security of Supply Guide, providing switchable N-1 for full abattoir capacity for 11 kV faults, enabling continued organic load growth in Highfield area, and cost-effective solution utilizing existing assets and design features.	FY27	FY29	2.4

Malvern industrial growth

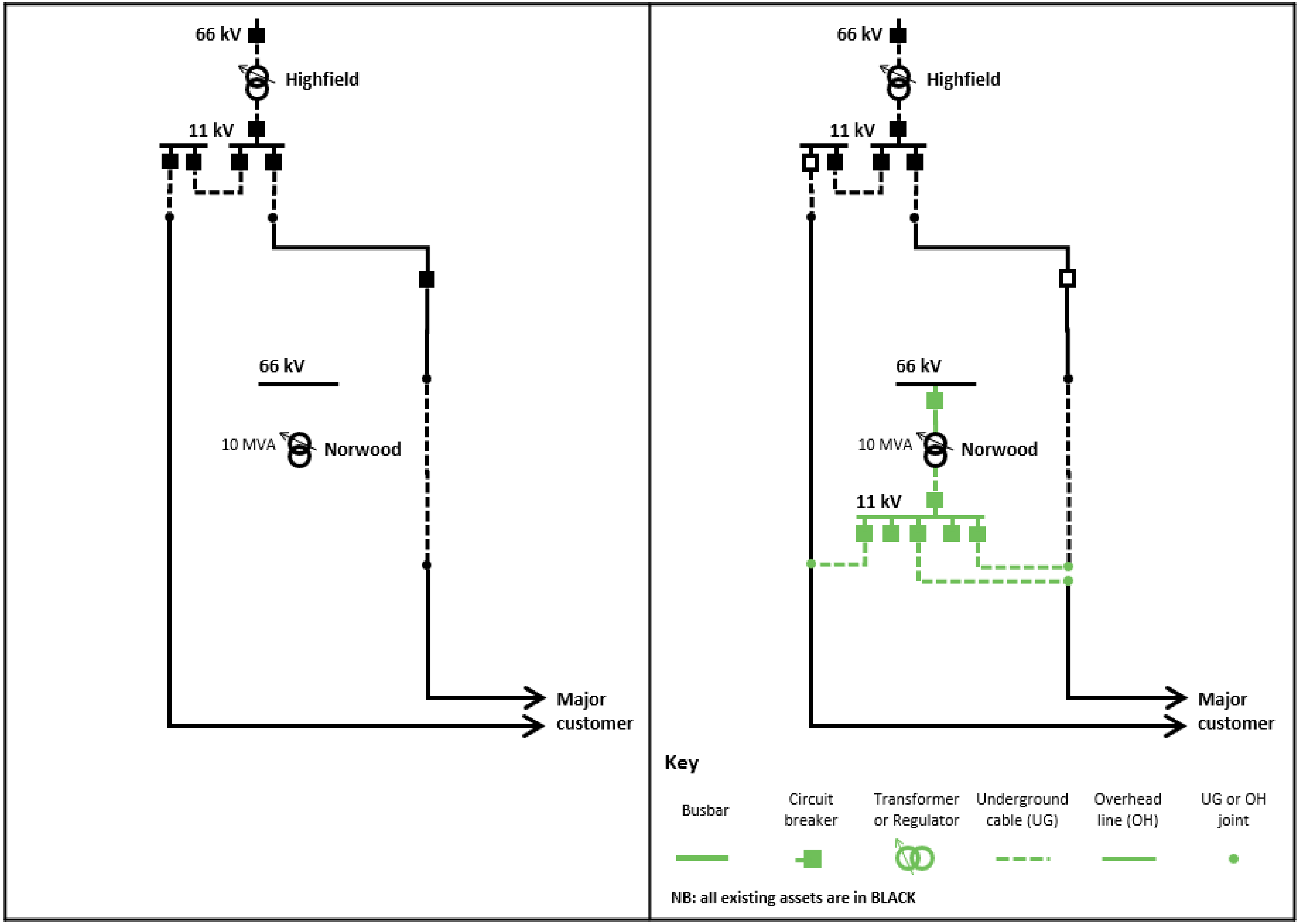

Table D.1 Orion's major system growth projects portfolio ($m, FY26 constant)

Project	Investment need	Shortlist options	Identified solution and benefits	From	To	Capex
New Burnham Zone Substation	This is a continuation of a project identified in prior AMPs to develop a new 66/11 kV 23 MVA capacity zone substation at Burnham.	N/A	N/A	FY27	FY27	3.8

New Burnham zone substation

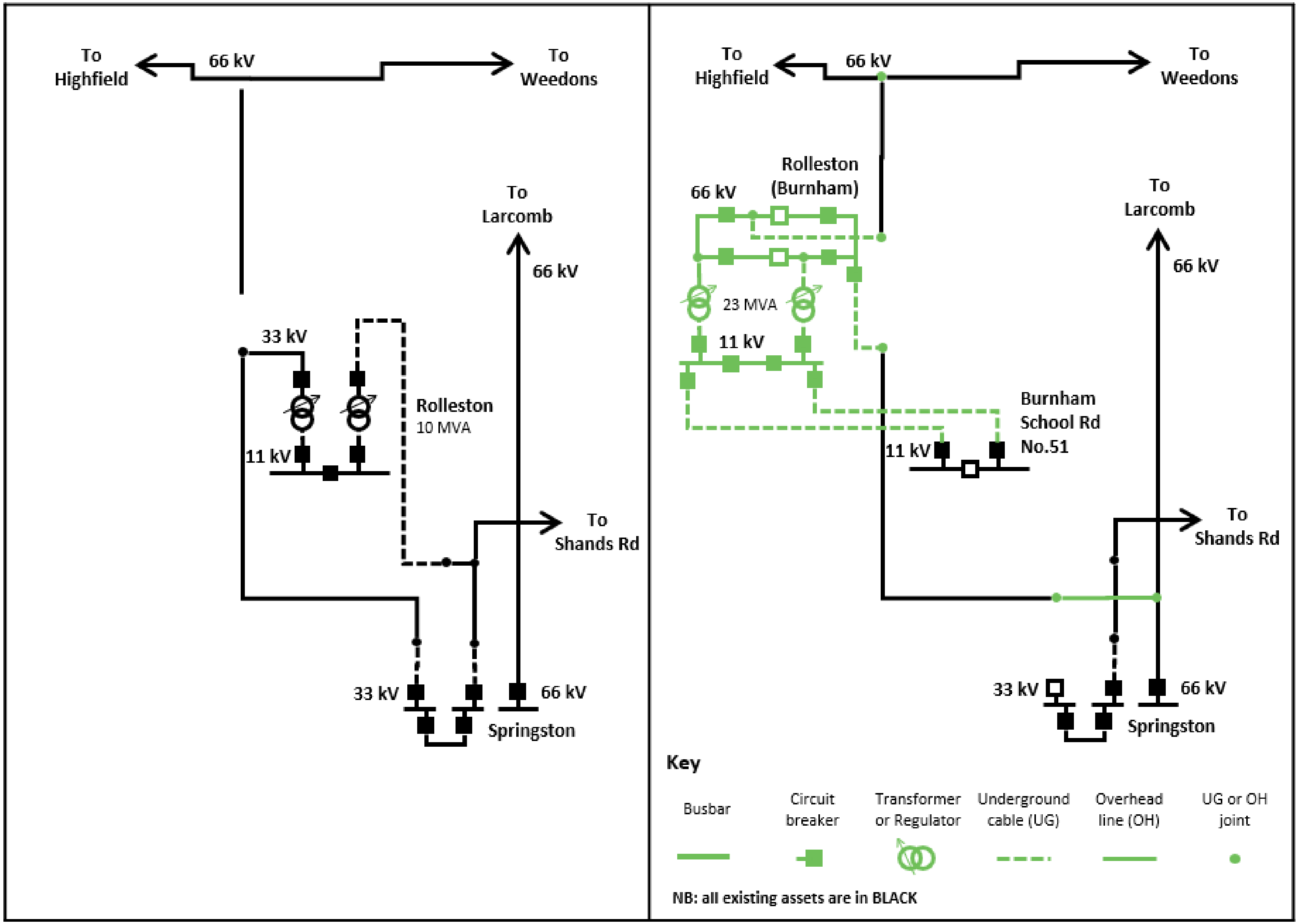

Table D.1 Orion's major system growth projects portfolio ($m, FY26 constant)

Project	Investment need	Shortlist options	Identified solution and benefits	From	To	Capex
Milton Hoon Hay cables + switchroom	This is a continuation of a project identified in prior AMPs to enable connection of the new 66kV cable circuits from Halswell zone substation and Milton zone substation.	N/A	N/A	FY27	FY27	1.0

Milton Hoon Hay cables + switchroom

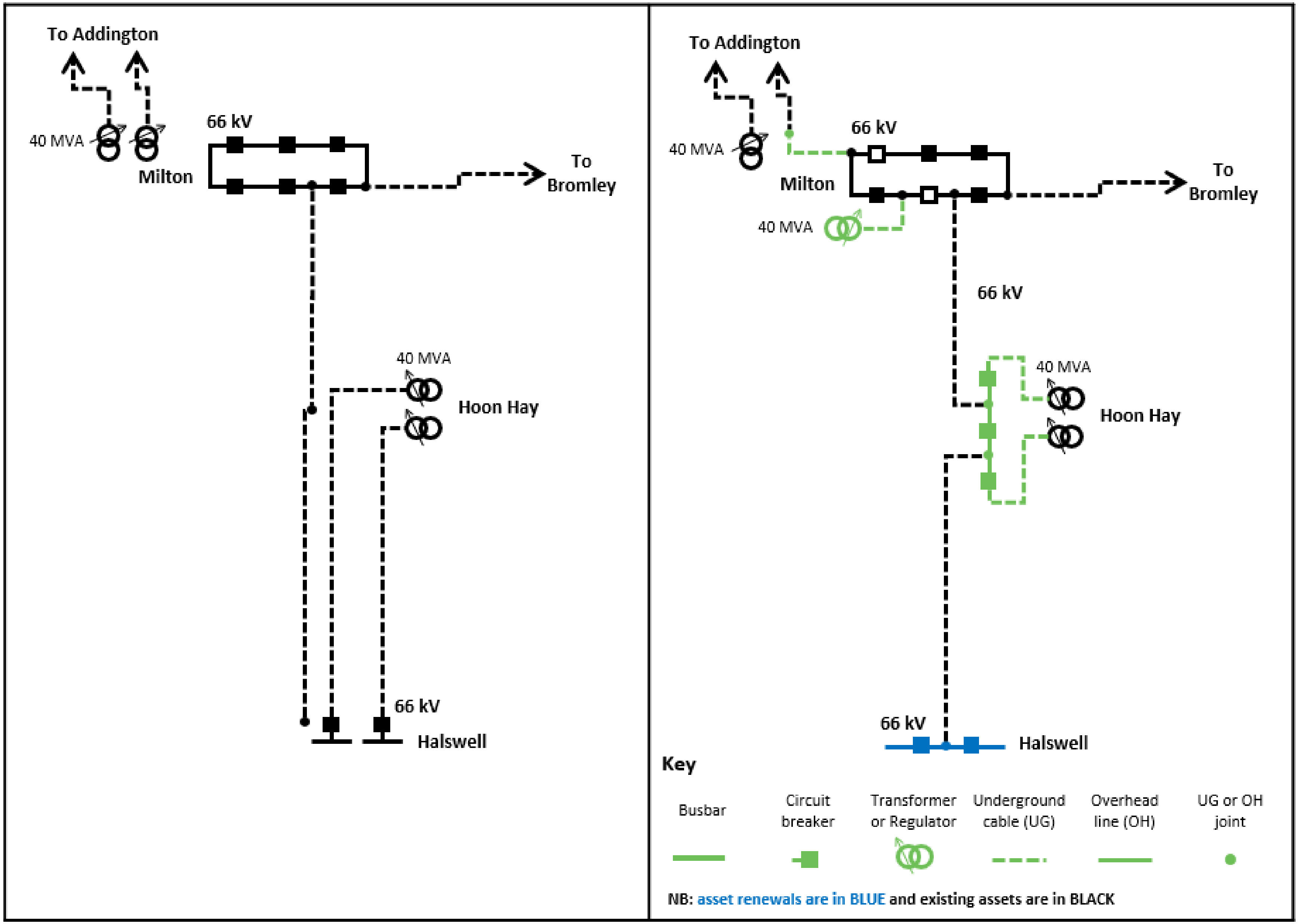

Table D.1 Orion's major system growth projects portfolio ($m, FY26 constant)

Project	Investment need	Shortlist options	Identified solution and benefits	From	To	Capex
Emergency spare transformers	Insufficient spare power transformer coverage to enable timely power restoration following catastrophic failures. Significant proportion of transformer fleet approaching end of life. Natural hazard risk (earthquakes, climate-driven fires/floods/storms) and Alpine Fault event expectation. Lead times for replacement transformers now 12-18 months.	**Option 1**: Do nothing. Maintains existing spare transformer coverage with aging spares. **Option 2**: Procure one 23 MVA 66/11 kV spare. Covers dual transformer substations without 11kV back-up but leaves 10MVA single transformer substations at risk. **Option 3**: Procure one 7.5/10 MVA 33/11 kV spare. Covers all single transformer substations but leaves 23 MVA dual transformer substations without 11 kV back-up at risk. **Option 4**: Procure both one 23 MVA 66/11 kV spare and one 7.5/10 MVA 33/11 kV spare.	**Selected Option 4**: Procure one 11.5/23 MVA 66/11 kV transformer and one 7.5/10 MVA 33/11 kV transformer. The 23MVA three-winding transformer reduces total spare count as it covers both 66 kV and 33 kV primary winding transformers and aligns with transformers being purchased for new Greenpark substation in Lincoln (initially 33 kV, future 66 kV upgrade). **Benefits include**: Ensures spare coverage for every voltage, rating, and vector group in transformer fleet; reduces extended outage risk following transformer failures; maintains reliability at N-1 secure substations by not requiring temporary spare relocation; supports resilience alignment with EEA Resilience Guide; enables power restoration within acceptable timeframes following catastrophic failures or natural hazard events.	FY28	FY29	3.0

Appendix E – Major asset renewal projects

This appendix provides detailed information on our major asset renewal projects planned during the AMP period.

Table E.1 Orion's major asset renewal projects ($m, FY26 constant)

Category	Major Renewal Projects	From	To	Capex
Subtransmission conductors	**Bromley to Heathcote 66kV conductor replacement** Replacement of deteriorating aluminium conductors on the Bromley–Heathcote 66 kV double circuit subtransmission line due to corrosion-related area loss exceeding Orion's replacement criteria.	FY30	FY31	4.6
	Halswell to Heathcote 66 kV conductor replacement Replacement of deteriorating aluminium conductors on the Halswell–Heathcote 66 kV double circuit subtransmission line due to corrosion-related area loss exceeding Orion's replacement criteria.	FY34	FY36	10.2
Subtransmission cables	**Halswell to Hoon Hay cable replacement** Continuation of project begun in FY26 to renew the aging 66 kV SCOF cable circuits with XLPE cables as part of the transition to a meshed Central City 66 kV network architecture, to improve resilience to seismic events.	FY27	FY27	0.3
	Milton to Oxford-Tuam cable installation and Oxford-Tuam 66 kV switchroom Installation of a new 66 kV XLPE cable circuit from Milton zone substation to a new 66 kV switching station adjacent to Oxford-Tuam zone substation, improving resilience to seismic events.	FY27	FY29	20.1
	Addington to Fendalton cable replacement Replacement of aging 66 kV SCOF cable circuits with XLPE cables as part of the transition from a radial to a meshed Central City 66 kV network architecture, improving resilience to seismic events.	FY28	FY30	23.6
	Oxford-Tuam to Lancaster cable installation Installation of a new 66 kV XLPE cable circuit linking Oxford-Tuam and Lancaster zone substations, extending the Central City 66 kV ring and providing an additional diverse supply path into the CBD.	FY29	FY31	10.9
	Papanui to McFaddens cable replacement Replacement of aging 66 kV SCOF cable circuits with XLPE cables as part of the transition from a radial to a meshed Central City 66 kV network architecture, improving resilience to seismic events.	FY30	FY32	16.5
	Addington to Armagh cable replacement Replacement of aging 66 kV SCOF cable circuits between Addington and Armagh zone substations with XLPE cables, as part of the transition from a radial to a meshed Central City 66 kV network architecture, improving resilience to seismic events.	FY32	FY34	27.7
	Addington to Milton cable replacement Replacement of the remaining 66 kV SCOF cable circuits between Addington and Milton zone substations with XLPE cables, as part of the transition from a radial to a meshed Central City 66 kV network architecture, improving resilience to seismic events.	FY35	FY36	10.0

Table E.1 Orion's major asset renewal projects ($m, FY26 constant)

Category	Major Renewal Projects	From	To	Capex
Zone substations	**Middleton ZS switchgear and building replacement** Continuation of a project begun in FY26 to replace end-of-life bulk oil 11 kV switchgear and switchroom buildings rated below Orion's 67% minimum new building standard seismic rating and which pose increasing health and safety risks due to arc flash exposure and structural vulnerability in a seismic event.	FY27	FY28	6.4
	Halswell ZS 66 kV outdoor switchgear replacement The multi-phase Milton–Halswell resilience programme is designed to improve route and supply diversity for Milton and Hoon Hay ZS. The programme includes the installation of two new 66 kV cables between Halswell and Milton ZS, along with new 66 kV switchgear at both Hoon Hay and Halswell to enable utilisation of the new cables. At Halswell ZS, the 66 kV switchgear installation is being coordinated with the replacement of existing 11 kV switchgear that has poor asset health and is due for renewal. This project relates specifically to the Halswell ZS switchgear installation and replacement component, which commenced in FY26.	FY27	FY28	8.3
	Little River ZS switchgear and transformer replacement Continuation of a project begun in FY26 to replace aging oil switchgear posing arc flash and fire risks, and a deteriorating transformer showing oil leaks and elevated gas levels.	FY27	FY27	0.3
	Diamond Harbour ZS 33kV switchgear replacement The 33kV switchgear and associated infrastructure at Diamond Harbour ZS presents several safety and operational concerns. The 11 kV and transformer secondary systems are also at the end of their expected life. Continuation of project begun in FY26 to install of new 33 kV indoor switchgear and extension of 11 kV control building.	FY27	FY28	1.9
	Darfield ZS asset replacement Full replacement of end-of-life 11 kV and 33 kV oil switchgear, a 59-year-old power transformer, and switchroom buildings rated below Orion's 67% minimum standard seismic rating and which pose increasing health and safety risks due to arc flash exposure and structural vulnerability in a seismic event.	FY27	FY28	3.5
	Addington ZS outdoor switchgear and transformer replacement Renewal of aging 66 kV outdoor switchgear, gantry structure, and transformer banks T6 and T7. This project includes installation of a new bus coupler to improve fault clearance and network resilience.	FY28	FY30	11.4
	Hororata ZS switchgear and transformer replacement Replacement of end-of-life oil switchgear, disconnectors, and power transformer, removing health and safety risks.	FY27	FY29	4.7
	Shands Road ZS rebuild Full rebuild of zone substation to address end-of-life switchgear, a transformer with a collapsed winding, and switchroom buildings rated below Orion's 67% minimum new building standard seismic rating and which pose increasing health and safety risks due to arc flash exposure and structural vulnerability in a seismic event, while accommodating forecast load growth.	FY29	FY31	10.7

Table E.1 Orion's major asset renewal projects ($m, FY26 constant)				
Category	**Major Renewal Projects**	**From**	**To**	**Capex**
	Dallington ZS switchgear replacement Replacement of end-of-life bulk oil 11 kV switchgear, which is beyond expected service life and poses increasing health and safety risks due to arc flash exposure and oil fire hazard.	FY29	FY30	6.1
	Bankside ZS switchgear replacement Replacement of end-of-life bulk oil switchgear and switchroom buildings rated below Orion's 67% minimum standard seismic rating and which pose increasing health and safety risks due to arc flash exposure and structural vulnerability in a seismic event.	FY31	FY32	2.4
	Portman ZS switchgear replacement Replacement of end-of-life bulk oil switchgear and a switchroom building rated below Orion's 67% minimum standard seismic rating and which pose increasing health and safety risks due to arc flash exposure and structural vulnerability in a seismic event.	FY31	FY32	3.5
	McFaddens ZS switchgear replacement Replacement of end-of-life bulk oil 11 kV switchgear and switchroom buildings rated below Orion's 67% minimum standard seismic rating and which pose increasing health and safety risks due to arc flash exposure and structural vulnerability in a seismic event.	FY31	FY32	6.3
	Papanui ZS disconnector replacement 8 of the 20 disconnectors on the 66kV busbars are at end-of-life which requires renewal towards the end of the forecast period.	FY33	FY33	0.3
	Annat ZS switchgear and transformer replacement 11 kV circuit breakers are approaching their average expected lifespan. The oil switchgear poses a higher risk to contractors and our staff than modern switchgear. There is also provision in the budget to renew modular building which is prone to issues such as moisture ingress.	FY33	FY34	2.1
	Moffett Street ZS switchgear replacement Replacement of end-of-life bulk oil switchgear and switchroom buildings rated below Orion's 67% minimum standard seismic rating and which pose increasing health and safety risks due to arc flash exposure and structural vulnerability in a seismic event.	FY30	FY31	3.9

Appendix F – Security of supply guide

Table F.1 Orion's security of supply guide					
Security Standard Class	**Description of area or customer type**	**Size of load (MW)**	**Single cable, line or transformer fault, N-1**	**Double cable, line or transformer fault, N-2**	**Bus or switchgear fault**
Transpower GXPs					
A1	GXPs supplying CBD, commercial or special industrial customers	15-600	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
B1	GXPs supplying predominantly metropolitan areas (suburbs or townships)	15-600	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
C1	GXPs supplying rural and semi- rural areas (Region B)	15-60	No interruption	Restore within 4 hours *(note 1)*	No interruption for 50% and restore rest within 4 hours *(note 1)*
D1	GXPs in remote areas	0-1	Restore in repair time	Restore in repair time	Restore in repair time
Orion 66 kV and 33 kV subtransmission network					
A2 (note 2)	Supplying CBD, commercial or special industrial customers	15-200	No interruption	Restore within 1 hour	No interruption for 50% and restore rest within 2 hours
A3	Supplying CBD, commercial or special industrial customers	2-15	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
B2 (note 2)	Supplying predominantly metropolitan areas (suburbs or townships)	15-200	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
B3	Supplying predominantly metropolitan areas (suburbs or townships)	1-15	Restore within 2 hours	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours

C2 (note 2)	Supplying predominantly rural and semi-rural areas (Region B)	15-200	No interruption	Restore within 4 hours *(note 1)*	No interruption for 50% and restore rest within 4 hours *(note 1)*
C3	Supplying predominantly rural and semi-rural areas (Region B)	4-15	Restore within 4 hours *(note 1)*	Restore 50% within 4 hours and the rest in repair time *(note 1)*	Restore within 4 hours *(note 1)*
C4	Supplying predominantly rural and semi-rural areas (Region B)	1-4	Restore within 4 hours *(note 1)*	Restore in repair time	Restore 75% within 4 hours and the rest in repair time *(note 1)*
Orion 11kV network					
A4	Supplying CBD, commercial or special industrial customers	2-4	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
A5	Supplying CBD, commercial or special industrial customers	0.5-2	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours (use generator)
A6	Supplying CBD, commercial or special industrial customers	0-0.5	Use generator to restore within 4 hours	Restore in repair time	Use generator to restore within 4 hours
B4	Supplying predominantly metropolitan areas (suburbs or townships)	0.5-4	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours use generator)
B5	Supplying predominantly metropolitan areas (suburbs or townships)	0-0.5	Use generator to restore within 4 hours	Restore in repair time	Use generator to restore within 4 hours
C5	Supplying predominantly rural and semi-rural areas (Region B)	1-4	Restore within 4 hours *(note 1)*	Restore in repair time	Restore 75% within 4 hours and the rest in repair time *(note 1)*
C6	Supplying predominantly rural and semi-rural areas (Region B)	0-1	Restore in repair time	Restore in repair time	Restore in repair time

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

Appendix G – Network maintenance approaches

This appendix provides an overview of our main maintenance activities. Given the large range of assets and types and the multiple interventions used, this summary is not intended to be exhaustive.

G1. Asset class maintenance forecasts

Our routine, corrective maintenance and inspections (RCI) forecast by asset class is set out in the following table.

Table G.1 RCI maintenance forecast by asset class ($m, FY26 constant)

Asset Class	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Overhead structures	4.32	5.30	6.42	6.56	6.85	7.75	6.71	6.53	6.81	6.84
Overhead conductors	1.30	1.65	2.57	2.59	2.60	2.62	2.35	1.58	1.60	1.62
Underground cables	1.40	1.51	1.29	1.30	1.32	1.34	1.36	1.38	1.40	1.41
Zone substations	2.60	2.95	3.19	3.22	3.03	3.07	3.04	2.96	3.00	3.03
Distribution switchgear	2.00	2.38	2.46	2.44	2.40	2.43	2.42	2.39	2.41	2.44
Distribution transformers	1.40	1.52	1.38	1.36	1.38	1.40	1.42	1.44	1.46	1.47
Secondary systems	0.56	0.99	1.11	1.11	0.92	0.92	0.93	0.84	0.74	0.75

G2. Overhead structures

G2.1 Poles

We inspect poles and undertake condition assessments on a periodic basis. It is critical to regularly inspect all poles because they may be damaged or compromised by third parties, land movement, deteriorating condition, or extreme weather events. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** (routine maintenance) tasks are set out in the table below. Preventive maintenance involves a combination of time-based inspections, preventive maintenance, and condition-based maintenance. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.2 Preventive maintenance schedule – poles

Tasks	Description	Frequency
Pole inspections	Visual inspection of poles and line components for defects, hammer sounding tests for timber poles. Condition assessment scores of 0-10: Below 0: red tag, immediate replacement 0-1: orange tag, replace within 3 months 2-3: plan for replacement within 24 months 4-9: continue periodic inspection/monitoring 10: new, defect free.	5 yearly.

Increased preventive maintenance activity is planned for:

- pole inspections, to bring all poles within their 5-year inspection cycle by FY29.
- pole top inspections (ground and drone), particularly to improve crossarm information.
- inspections of local telecommunications poles that carry our assets. We need to inspect the poles, in alignment with our standard, to better understand the implications of accepting ownership of the poles, which are expected to be divested to us.

Corrective maintenance includes work such as replacement of guy wires, bolts, signs and guards that are missing or in poor condition.

Additional corrective maintenance will be required during the AMP period, from FY27, to remediate the additional defects that will be identified due to the increased focus on preventive maintenance. Many of them do not comply with our standard pole specification.

Reactive maintenance includes responding to a pole top hardware failure or a car versus pole incident.

G2.2 Crossarms

We inspect and test crossarms and undertake condition assessments on a periodic basis, as part of the pole inspection regime and supplemented by drone inspections. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** tasks are set out in the table below.

Table G.3 Preventive maintenance schedule – crossarms

Task	Description	Frequency
Pole-top inspections	Visual inspection of crossarms for defects.	5 yearly, as part of pole inspection programme.
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.	When requested.

Increased preventive maintenance activity is planned to provide for increased pole top inspections (ground and drone), particularly to improve crossarm information.

Corrective maintenance includes work such as repair or replacement of minor components of the crossarm assembly.

Additional corrective maintenance will be required during the AMP period, from FY27, to remediate the additional defects that will be identified due to the increased focus on preventive maintenance.

We are resuming our full overhead line defects programme during the AMP period. As well as retightening conductor hardware, this will include replacing degraded or problematic conductors, crossarm components and full crossarm assemblies. This programme has been on hold for several years due to budgetary constraints.

Reactive maintenance on crossarms is conducted when an in-service failure occurs or a defect is identified that presents an immediate risk to supply or safety, with the objective of returning assets safely to service to minimise disruption to supply. Examples include responding to a pole top hardware failure or when vegetation damages pole-top equipment.

G2.3 Steel Structures

We inspect and test steel structures and undertake condition assessments on a periodic basis. It is critical to regularly inspect all towers because they may be damaged or compromised by external parties, land movement, deteriorating condition, or extreme weather events. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** task is set out in the table below. Preventive maintenance involves a combination of time-based inspections, preventive maintenance, and condition-based maintenance. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.4 Preventive maintenance schedule – steel structures

Task	Description	Frequency
Tower inspections and condition assessment	Visual and lifting inspections (inspect below conductor fixtures) provide condition assessment of the tower steel, bolts, attachment points, insulators, hardware, and conductors. Condition assessment scores range from 100 (new galvanised coating, bright shiny or slightly dull grey appearance) to 0 (structural failure under 'everyday conditions' possible). The scores are used to forecast an intervention point, taking in account the corrosion zone the tower is located in.	5 years for visual inspection. 20 years each circuit (10 years each line) for lifting inspection.

Increased preventive maintenance activity to prioritise testing of steel towers on public land and/or near residential properties or schools for earth potential rise and transferred voltages, through current injection and step touch potential tests.

Corrective maintenance includes work such as replacement of individual steel members and signage.

Reactive maintenance on steel structures is conducted when an in-service failure occurs or a defect is identified that presents an immediate risk to supply or safety, with the objective of returning assets safely to service to minimise disruption to supply. Examples include fixing failed insulators or attachment points.

G3. Overhead conductors

G3.1 Subtransmission conductors

We inspect and test overhead conductors and undertake condition assessments on a periodic basis. It is critical to regularly inspect conductors because they may be damaged by extreme weather events or show deteriorating condition. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.5 Preventive maintenance schedule – subtransmission conductors

Tasks	Description	Frequency
Pole conductor inspection	Carried out with pole inspections, this is a visual inspection of lines for defects.	5 years
Tower conductor inspection	Visual condition assessment of conductors, carried out with tower inspections.	8 years
Conductor testing	Non-destructive in situ testing.	As required
Subtransmission thermographic survey	Detect localised temperature rise on components which can be due to a defect.	2 years

Increased preventive maintenance activity is planned for:

- undertaking a conductor verification survey, from FY28, to improve our data and give us better confidence when developing and prioritising our conductor replacement programmes. Currently, there is scope to improve our conductor type/material/size data
- using drones to identify bird cages, strand breakages, and corrosion to improve subtransmission conductor condition assessment
- sending crews out to confirm some conductor types, sizes, and materials to ensure our asset data is correct in that regard
- performing forensic destructive sampling of distribution and LV conductors and using the results to validate Cormon test results on our subtransmission lines
- undertaking additional Cormon testing of our 66 kV conductors.

Corrective maintenance includes resuming our full overhead line defects programme during the AMP period. This involves retightening of hardware and the replacement of degraded or problematic components (if needed) including insulators, dissimilar metal joints, HV fuses, binders, and crossarms.

Reactive maintenance on overhead conductors includes responding to faults when conductor or fittings fail, or when vegetation falls on the lines due to storms.

G3.2 Distribution conductors

We inspect and test overhead conductors and undertake condition assessments on a periodic basis. It is critical to regularly inspect conductors because they may be damaged by extreme weather events or show deteriorating condition. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.6 Preventive maintenance schedule – distribution conductors

Tasks	Description	Frequency
Pole conductor inspections	Carried out with pole inspections, this is a visual inspection of lines for defects.	5 years

Increased preventive maintenance activity is planned for:

- undertaking a conductor verification survey, from FY28, to improve our data and give us better confidence when developing and prioritising our conductor replacement programmes. Currently, there is scope to improve our conductor type, material, and size data
- forensic destructive sampling of distribution (and LV) conductors to better understand their expected lives (from FY26).

Corrective maintenance includes resuming our overhead line defects programme during the AMP period, as outlined in the subtransmission conductors section.

Reactive maintenance includes our response to defects or faults to ensure we can safely return assets to service to minimise disruption to customers. Examples include emergency hardware repairs or restoring a fallen conductor.

G3.3 Low voltage conductors

Our approach for LV conductors is the same as for distribution conductors as set out in Section 2.2 of this Appendix.

G4. Underground cables

G4.1 Subtransmission cables

We inspect and test underground cable assets to the extent practicable. However, as our cables are relatively inaccessible, we focus our inspections and associated corrective maintenance on the cable terminations which are accessible and susceptible to failure when exposed to damp or contaminated conditions. We obtain information on our underground cable assets to the extent possible when above ground assets are inspected, or when work is carried out on joints and terminations.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.7 Preventive maintenance schedule – subtransmission cables

Tasks	Description	Frequency
Subtransmission cable inspections	Oil-filled cable oil level checks.	2 months.
	Cable sheath tests and repairs, pressure checks, inspection of terminations/support structures.	Annually to 4 years.
	Partial discharge testing.	As required.
	New or repaired cable benchmark testing.	As required.

Corrective maintenance includes work such as repairs for existing oil pressure equipment, topping of oil when there is low oil in the cables, replacing / repairing joints or terminations or sheaths, and repairing components on ancillary equipment, e.g., gauges and alarm contacts.

Reactive maintenance included immediate emergency repairs on cable terminations and oil leaks on the 66 kV subtransmission cables.

G4.2 Distribution cables

As the distribution cables are underground, we do not carry out condition assessments of these assets, except for regular inspections of terminations. Our assessment of cable condition has generally been limited to using what we know about the cable, i.e. age, type, and any failures it has experienced, together with any feedback received on internal condition from contractors carrying out cable fault repairs.

We focus our inspections and associated corrective maintenance on the cable terminations which are accessible and susceptible to failure when exposed to damp or contaminated conditions. We obtain information on the underground cable assets to the extent possible when above ground assets are inspected or when work is carried out on joints and terminations.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.8 Preventive maintenance schedule – distribution cables

Tasks	Description	Frequency
Distribution cable inspection and testing	Inspections of Magnefix Switching Units (MSUs) terminations for deterioration, reporting grease terms and surface partial discharge.	6 months
	Diagnostic partial discharge and tan delta testing.	Targeted, ongoing

There are no increases in preventive maintenance expenditure for this fleet.

Corrective maintenance includes work such as maintenance of MSU terminations, which are prone to failure if exposed to damp or contamination, and installing more cables seals around our distribution substations.

We expect an increase in corrective works for this asset class going forward, to address any defects identified by sheath integrity tests or other cable tests, which typically require overseas specialist resource. This is reflected in a step change in expenditure from FY28.

Reactive maintenance on distribution cables is conducted when a defect or fault is identified that presents an immediate risk to supply or safety, with the objective of returning assets safely to service to minimise disruption to supply. Examples include vandalism, vehicle collision, and weather-related events that cause a failure in the underground to overhead termination located on a pole.

G4.3 Low voltage cables

We inspect and test underground cable assets to the extent practicable. We also inspect all distribution boxes, cabinets, and kiosks on a regular basis for safety reasons and to avoid damage to the equipment contained within.

As with the other cable types, we do not carry out condition assessments, except for regular inspections of terminations. Our assessment of cable condition has generally been limited to using what we know about the cable, i.e. age, type, and any failures it has experienced, together with any feedback received on internal condition from contractors carrying out cable fault repairs.

We focus our inspections and associated corrective maintenance on the cable terminations which are accessible and susceptible to failure when exposed to damp or contaminated conditions. We obtain information on the underground cable assets to the extent possible when above ground assets are inspected or when work is carried out on joints and terminations.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.9 Preventive maintenance schedule – LV cables

Tasks	Description	Frequency
Low voltage cable inspections	Visual inspections of insulation on cable to overhead terminations.	5 years
	Visual inspection of above ground (distribution boxes and cabinets) and terminations.	5 years

There are no increases in preventive maintenance expenditure for this fleet.

Reactive maintenance on LV cables is conducted when a defect or fault is identified that presents an immediate risk to supply or safety, with the objective of returning assets safely to service to minimise disruption to supply. Examples include vandalism, vehicle collision, and weather-related events that cause a failure in the underground to overhead termination located on a pole.

G5. Zone substations

G5.1 Power transformers

We test and maintain our power transformers annually to assess their condition and ensure satisfactory operation. Our inspection and maintenance programme shows that most of our power transformers are in good serviceable condition, while a small number are approaching end of life and will need to be replaced during the AMP period. Some of the older transformers have moderate oil leaks or external condition deterioration. Where needed, we carry out mid-life corrective maintenance, including painting and replacing ancillary equipment.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.10 Preventive maintenance schedule – power transformers

Fleet	Activity	Frequency
Zone substations	Overall visual inspection, including the power transformers.	2 months
Power transformers	Minor visual inspection and functionality check.	2 months
	Shutdown service – detailed inspection & functional check.	Annual
	Oil diagnostics – Dissolved Gas Analysis (DGA) and oil quality tests.	Annual (or more if required)
	Online oil treatment to reduce moisture levels.	2 years or more often as required

Table G.10 Preventive maintenance schedule – power transformers

Fleet	Activity	Frequency
	Tap changer maintenance – intrusive maintenance and parts replacement per manufacturer instructions.	4 years (oil) 8 years (vacuum)
	L1 and 2 electrical diagnostics – Polarisation index & DC insulation resistance, DC winding resistance, winding ratio test.	4 or 8 years

Increased preventive maintenance activity is planned to provide for power transformer bund leak inspections, ensuring the required bunded area for each of our 85 power transformers is inspected for leaks.

Corrective maintenance includes work such as non-urgent repairs to assets following inspection or fault. We also carry out half-life maintenance on our power transformers, which involves painting/managing corrosion, changing the transformer oil, replacing gaskets etc. This enhances their reliability.

Reactive maintenance includes our response to defects or faults to ensure we can safely return assets to service to minimise disruption to customers. Examples include going to a site after a low alarm to investigate, attending to a fan fail alarm, and responding to tap changer issues.

G5.2 Outdoor switchgear

We inspect and test zone substation assets and undertake condition assessments on a periodic basis. It is critical to regularly inspect all zone substation assets because they may be damaged or compromised by an external party, land movement, deteriorating condition, vermin or bird activity, or extreme weather events. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.11 Preventive maintenance schedule – outdoor switchgear

Fleets	Activity	Frequency
Outdoor and indoor switchgear	Minor visual inspections and functionality check. Dusting, removal of bird nests.	2 months
	Disconnector scheduled maintenance – clean, inspect, and lubricate moving parts and contacts. Clean insulators, inspect terminations.	4 or 8 years
	Circuit breakers - scheduled maintenance – clean and lubricate moving parts, repair or replace contacts, tripping tests, electrical diagnostic tests, service or replace oil.	4 or 8 years
	Circuit breakers – non-intrusive survey of equipment using online partial discharge detection methods to identify insulation defects.	Variable based on age, criticality and defect history of the asset.

Corrective maintenance includes non-urgent repairs to assets following inspection or fault.

Reactive maintenance includes our response to defects or faults to ensure we can safely return assets to service to minimise disruption to customers. Examples include emergency maintenance on some of our older 33 kV and 66 kV disconnectors which were experiencing performance issues.

G5.3 Indoor switchgear

We inspect and test zone substation assets and undertake condition assessments on a periodic basis. It is critical to regularly inspect all zone substation assets because they may be damaged or compromised by land movement or deteriorating condition. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.12 Preventive maintenance schedule – indoor switchgear

Fleets	Activity	Frequency
Outdoor and indoor switchgear	Minor visual inspections and functionality check. Dusting, removal of bird nests.	2 months
	Disconnector scheduled maintenance – clean, inspect, and lubricate moving parts and contacts. Clean insulators, inspect terminations.	4 or 8 years
	Circuit breakers - scheduled maintenance – clean and lubricate moving parts, repair or replace contacts, tripping tests, electrical diagnostic tests, service or replace oil.	4 or 8 years
	Circuit breakers – non-intrusive survey of equipment using online partial discharge detection methods to identify insulation defects.	Variable based on age, criticality and defect history of the asset

Corrective maintenance includes work such as non-urgent repairs to assets following inspection or fault.

Reactive maintenance includes our response to defects or faults to ensure we can safely return assets to service to minimise disruption to customers. Examples include emergency maintenance on some of our older 66 kV disconnectors which were experiencing performance issues.

G5.4 Buildings and grounds

We inspect and test zone substation assets and undertake condition assessments on a periodic basis. It is critical to regularly inspect all zone substation assets because they may be damaged or compromised by an external party, land movement, deteriorating condition, vermin or bird activity, or extreme weather events. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.13 Preventive maintenance schedule – buildings and grounds

Fleets	Activity	Frequency
Zone substations	Overall visual inspection.	2 months
Grounds	We undertake risk-based testing of site earth grids.	Testing frequencies depend on site criticality and soil conditions.
Buildings and grounds	Visual inspection and condition assessment of building assets to identify maintenance needs.	3 years Starting from FY27 the frequency will change to annually.

Table G.13 Preventive maintenance schedule – buildings and grounds

Fleets	Activity	Frequency
	Maintenance of grounds, ensuring switchyards are free of vegetation, and gutters and downpipes are free of any blockages.	3 weeks

Increased preventive maintenance activity is planned to for:

- performing NBS assessments on the likely seismic performance of zone substation buildings on a cyclical basis to ensure alignment with any changes to the Building Code, reassessing following major modifications or additions, and evaluating any deterioration over time
- ensuring buildings and grounds inspections and assessments are completed annually, including fencing, security, retaining walls, vegetation, and driveways
- inspections and condition assessments of lighting and communications towers and masts and lattice structures
- power transformer bund leak inspections (refer to Section 4.1 of this Appendix).

Corrective maintenance includes work such as building repairs and painting, and non-urgent repairs to assets following inspection or fault, together with removal and/or encapsulation of asbestos in buildings.

Reactive maintenance on the buildings and grounds fleet includes our response to defects or faults to ensure we can safely return assets to service to minimise disruption to customers. Examples include responding to alarms or access/security issues at zone substations

G5.5 Ancillary equipment

We inspect and test zone substation assets and undertake condition assessments on a periodic basis. It is critical to regularly inspect all zone substation assets because they may be damaged or compromised by an external party, land movement, or deteriorating condition. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.14 Preventive maintenance schedule – ancillary equipment

Tasks	Description	Frequency
Ripple Injection Plant	Inspection of control and injection cabinets, measurements and testing, repairs e.g. replacing contactors on injection plant if overheating detected.	Annual

Corrective maintenance includes work such as non-urgent repairs to assets following inspection or fault.

Reactive maintenance includes our response to defects or faults to ensure we can safely return assets to service to minimise disruption to customers.

G6. Distribution switchgear

G6.1 Pole mounted switchgear

Our pole mounted switchgear is inspected (and if relevant, serviced) as part of our pole inspections programme. Identified defects and end of life switchgear are scheduled for remediation and replacement, respectively.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.15 Preventive maintenance schedule – pole mounted switchgear

Description	Frequency
Inspections – all pole mounted switchgear is inspected as part of overhead lines inspections.	5 years
ABI and line circuit breaker scheduled maintenance – clean, inspect, and lubricate moving parts and contacts. Clean insulators and inspect terminations.	5 years
Line switches scheduled maintenance – exterior and control relay are inspected annually. Our SCADA provides initial indication of problems.	12 months (inspection) 8 years (servicing)

Corrective maintenance includes defect remediation, to address issues identified during inspections or fault response. It may also include additional testing or maintenance targeted at assets with poorer condition or reliability to maintain their performance and mitigate against failure.

Reactive maintenance on pole mounted switchgear is conducted when an in-service failure occurs, or a defect is identified that presents an immediate risk to supply or safety.

G6.2 Pole mounted fuses

Our pole mounted fuses are inspected as part of our overhead lines inspection, with proactive replacements scheduled from this.

Our main **preventive maintenance** task is set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.16 Preventive maintenance schedule – pole mounted fuses

Description	Frequency
Inspections – all pole mounted fuses are inspected as part of overhead lines inspections.	5 years

Reactive maintenance includes the replacement of fuse cartridges within the pole mounted fuse assembly when they blow.

G6.3 Ground mounted switchgear

It is critical to regularly inspect ground mounted switchgear, particularly, because it may be damaged or compromised by an external party, land movement, or extreme weather events. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.17 Preventive maintenance schedule – ground mounted switchgear

Description	Frequency
MSU inspections (check heater operation, signs of partial discharge, dust covers fitted). Report defects or contamination found and schedule maintenance (remove surface contamination and corrosion).	6 months (inspection) 4 years (servicing)
RMU inspections - inspect and report defects, schedule maintenance.	6 months

Corrective maintenance includes work such as defect remediation, to address issues identified during inspections or fault response. It may also include additional testing or maintenance targeted at assets with poorer condition or reliability to maintain their performance and mitigate against failure.

Reactive maintenance includes responding to failures of RMUs.

G6.4 Enclosures

Our enclosures fleet is generally in reasonable condition. It is critical to regularly inspect enclosures, particularly, because it may be damaged or compromised by an external party, land movement, or extreme weather events. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.18 Preventive maintenance schedule – enclosures

Description	Frequency
Distribution substation buildings / kiosk inspections – paint quality, dust level, grease leak, corona discharge on assets, vegetation.	6 months
Distribution substation buildings and grounds visual inspection.	3 years. Starting from FY27 the frequency will change to 2 yearly
Visual inspection of distribution cabinets and boxes.	5 years

Increases in preventive maintenance expenditure are planned to provide for:

- survey of enclosure assets to confirm asset information
- distribution substation building asbestos surveys and testing
- detailed seismic assessments on the likely seismic performance (NBS) of distribution buildings
- changing the frequency of inspections for building, fencing, security, retaining walls, and driveways from 3 yearly to 2 yearly
- engage external fire engineering consultants to undertake fire risk assessments on our kiosks and distribution substations that do not comply with AS2067 fire separation requirements
- soil contamination testing to identify and manage any per- and poly- fluorinated alkyl substances and other hazardous substances in distribution substations.

Corrective maintenance includes work such as:

- Painting and repainting of kiosks, especially to prevent rust in coastal areas. This task is carried out periodically but with the timing determined from inspections.
- Remediation related to the new preventive maintenance tasks set out above, from FY28. This includes asbestos removal or encapsulation (if the asbestos is at risk of being dispersed), fixing driveways (potholes), security fencing, security and fire alarm systems, minor roof leaks, doors, and painting.
- Rectifying and waterproofing any ground mounted switchgear that have cable entries which are either not sealed or the seals have deteriorated. As we inspect more of these, we are expecting an increase in the need to rectify these.

Reactive maintenance includes repairs to LV enclosures following vehicular or other damage where the enclosure cannot be safely left as is.

G6.5 Ancillary equipment

We inspect surge arresters on a periodic basis to ensure network equipment is protected against voltage surges.

Our main **preventive maintenance** task is set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.19 Preventive maintenance schedule – ancillary equipment

Description	Frequency
Surge arresters are inspected as part of overhead lines inspections.	5 years

G7. Distribution transformers

G7.1 Ground mounted transformers

We carry out regular inspections and condition-based repairs on our distribution transformer assets. Inspections of ground mounted transformers are relatively frequent as we need to ensure security and safety.

Our main **preventive maintenance** tasks are set out in the table below. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets and to schedule corrective maintenance or renewal if at end of life. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.20 Preventive maintenance schedule – ground mounted transformers

Description	Frequency
Visual inspection checking for damage to the transformer including cracked or damaged bushings, corrosion, unsecured covers, signs of oil leakage, and paintwork. Minor repairs to ground mounted transformers as necessary.	6 Months

Increased preventive maintenance activity is planned to provide for, from FY27:

- Improved inspections and testing of large ground mounted transformers, including assessment for fire risk mitigation requirements and introducing dissolved gas analysis for large ground mounted transformers to enable early detection of internal faults, helping to prevent costly failures and extend asset life.

- Additional inspections will enable collection of data to support the proactive renewals programme which will ramp up over the AMP period.

Corrective maintenance includes work such as oil leak repairs, remediating loose or corroded terminals, and bushing replacement.

Reactive maintenance includes work to rectify asset failure, third party damage such as where a ground mounted transformer is struck by a vehicle, or adverse weather damage.

G7.2 Pole mounted transformers

We carry out regular inspections and condition-based repairs on our distribution transformer assets. Pole mounted transformers are inspected only as part of periodic visual overhead line inspections.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.21 Preventive maintenance schedule – pole mounted transformers

Description	Frequency
Visual inspection checking for damage to the transformer including cracked or damaged bushings, corrosion, unsecured covers, signs of oil leakage, paintwork.	5 years (part of overhead network inspection)

Corrective maintenance includes work such as oil leak repairs, bushing replacements, remediating loose or corroded terminals, and repairing bird damage.

Reactive maintenance is conducted when an in-service failure occurs or a defect is identified that presents an immediate risk to supply or safety. Examples include asset failure, or adverse weather damage.

G7.3 Voltage regulators and capacitors

We carry out regular inspections and condition-based repairs on our distribution transformer assets. Preventive maintenance also allows us to collect condition information to support analysis and decision making around these assets and to schedule corrective maintenance or renewal if at end of life.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.22 Preventive maintenance schedule – voltage regulators and capacitors

Tasks	Description	Frequency
Voltage regulators inspection and maintenance	Detailed inspection and maintenance of internals. Inspect and maintain tap changer. Functional test of control circuits. Test insulation resistance, test oil and treat for acidity and carbon build up.	6 months (inspection). 4 yearly (maintenance).

Table G.22 Preventive maintenance schedule – voltage regulators and capacitors

Tasks	Description	Frequency
STATCOM inspection and maintenance	Annual inspection and maintenance by manufacturer.	Annual.

Increased preventive maintenance activity is planned to provide for testing and condition assessment of ferro-resonance capacitors.

Corrective maintenance includes work such as tap changer repairs.

Reactive maintenance is conducted when an in-service failure occurs or a defect is identified that presents an immediate risk to supply or safety.

G7.4 Generators

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.23 Preventive maintenance schedule – generators

Tasks	Description	Frequency
Mobile generators scheduled maintenance	Oil change (shorter interval for older engines). Diesel and batteries tests. Complete functional test.	250 hours. Annual. Annual.
Emergency generators scheduled maintenance	Oil test and change	Oil test annually. Oil change every 3 years / 500 hours (whichever comes first).
	Change tank fuel air filters.	3 years.
	Diesel and battery test. Run on load bank for 30 mins at full load.	Annual.
	Test run.	Monthly.

G8. Secondary systems

G8.1 Protection

We carry out regular inspections of our protection systems including a visual inspection, display and error message checking and wiring and termination conditions. Protection systems are periodically checked for calibration and operation as part of the substation maintenance/testing rounds. The frequency of inspections and maintenance/testing of our protection system varies with location.

The condition of protection assets is difficult to assess due to there being no physical signs of deterioration, internal oxidation of contacts, or component aging on visual inspection. Full-scale testing requires simulating actual fault conditions, which is difficult and disruptive to the network. During maintenance rounds existing settings are compared against Stationware (protection database) and binary pass/fail assessment is done to check their operation.

Electromechanical relays require ongoing calibration due to 'drift' of components.

Our IEDs have self-testing and diagnosis capability which detect most failure modes. These devices are prone to failure as they age due to the expected life of electronic components. Obsolescence of IEDs is determined by firmware support and compatibility with newer technology.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.24 Preventive maintenance schedule – protection

Tasks	Description	Frequency
Protection testing and inspections at zone substations	Inspection – check relay flags	2 months
	Protection testing	4 or 8 years
Protection testing and inspections at distribution substations	Inspection – check relay flags	6 months
	Protection testing	8 years
Protection testing and inspections – line circuit breakers	Inspection – check relay flags	Annual
	Protection testing	8 years
Protection testing and inspections – all 11 kV trunk feeder sites	Unit protection testing	4 years

Increased preventive maintenance activity is planned to increase the number of IED points tested to include those monitoring relay or IED health. Currently these are only tested at commissioning.

Reactive maintenance is conducted when an in-service failure occurs or a defect is identified that presents an immediate risk to supply or safety, with the objective of returning assets safely to service to minimise disruption to supply. An example is when IED failures are identified, where SCADA-monitored.

G8.2 Signalling/communications cables

As these cables are underground, we do not carry out condition assessments of these assets, except for regular inspections of terminations.

Increased preventive maintenance activity is planned to provide for testing of copper pilot cables to assess condition to inform our renewal activity / replacements and ensure related asset data is complete, particularly around spare cable cores.

Reactive maintenance includes work resulting from third party diggers hitting or damaging our cables during excavation, resulting in a failure.

G8.3 SCADA (RTUs)

We do not collect condition data for our RTUs.

Corrective maintenance includes work such as swapping out faulty I/O modules, or reinstalling firmware to recover RTUs.

G8.4 Communications

Our communication systems are largely maintenance free. Because equipment is monitored, with faulty items identified remotely and repaired quickly, failure consequences are generally low.

We do not have a specific maintenance plan for communications cables but rather undertake repairs when identified.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.25 Preventive maintenance schedule – Communications

Tasks	Description	Frequency
Communication mast inspections	Visual inspection as part of zone substation inspections.	2 months
	Targeted inspections on masts affected by winds in the lee of mountains.	Annually

G8.5 Batteries and DC supplies

We test batteries using discharge testing and replace those in poor condition.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.26 Preventive maintenance schedule – batteries and DC supplies

Description	Frequency
Inspection, cleaning, condition testing, and impedance testing (down to 48 V).	2 months. Annual (impedance test).

Corrective maintenance includes work such as replacing failed modules in battery chargers.

Reactive maintenance includes replacing chargers that have failed.

G8.6 Metering

We regularly inspect metering sites, carry out appropriate calibration checks and witness the calibration checks on Transpower's metering. Our meter test service delivery partners 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.

Our main **preventive maintenance** tasks are set out in the table below. Development of the table below considered relevant legislative and regulatory requirements, manufacturer recommendations, and good electricity industry practice.

Table G.27 Preventive maintenance schedule – metering

Tasks	Description	Frequency
CT and VT recalibration.	Required in line with the EIPC.	10 years.

Appendix H – Innovation activity at Orion

The following table summarises Orion's innovation activity during FY26, including trials, pilots, and ongoing programmes.

Appendix H.1 Orion's innovation activity in FY26

Start date	Activity name	Description	Status	Collaborators
FY23	'Visibility and System Insights for the Orion Network' ViSION	This project aimed to improve visibility and insights gained across the network from GXP through to behind the meter – via monitoring, smart meter data, analytical technology and smart processes. The insights developed through our ViSION project will help unlock latent capacity in Orion's LV network, thereby reducing the need for future network investment, lower costs to our customers, and deliver numerous other efficiency, quality and safety improvements. Phase 2 of this project was completed in 2025 and an Innovation Project Allowance learning report shared - see ViSION | The Orion Group.	Complete (FY26)	
FY24	LiDAR capture of subtransmission towers	We partnered with an Australian based company (Neara) to capture and display our towers in urban Christchurch to check for electrical and vegetation clearances. We have extended capturing LiDAR data via helicopter, fixed wing and drone on other areas of our network and are utilising Neara to check for any encroachment over time. We are currently evaluating the use of this to determine the optimal approach for capturing and updating data towards quality, time and cost efficiencies.	Complete (FY26)	
FY26	Unlocking Latent Capacity through Phase Balancing	We tested whether low-cost, data-driven LV network optimisation techniques could unlock additional hosting capacity and defer traditional network reinforcement. Using smart meter and LV monitoring data, we demonstrated that both manual phase balancing and network reconfiguration can release meaningful capacity—particularly through reconfiguration—while highlighting the importance of accurate phasing, high-quality data, and improved modelling to scale these approaches across the network.	Complete (FY26)	
FY26	Future-Grid Compass LV Analytics	We implemented the Future-Grid Compass LV analytics platform to turn newly available smart-meter and LV monitoring data into actionable network insights. The project validated Compass' ability to accurately reflect real LV network conditions, integrate multiple datasets, and support everyday decision-making. Now live in production, the platform has improved LV visibility across Network Development, Operations and Connections, enabling better understanding of loading, voltage, topology errors and customer phasing, and providing a foundation for more proactive, data-driven LV network management as use cases continue to expand.	Complete (FY26)	
FY27	LV cable health trial	We have applied for INTSA to support a proposed collaboration between EA Technology and several EDBs to enhance understanding of LV network	Planned	EA Technology and several EDBs

Appendix H.1 Orion's innovation activity in FY26

Start date	Activity name	Description	Status	Collaborators
		condition, failure prediction, and asset management practices across New Zealand, by trialling LV monitors to share and analyse cable condition correlations across cable make, model, age, country, etc. to guide investment and support reliable LV networks.		
FY23	Hot water projects	Enabling local hot water load management with retailers to maximise whole-of-system value to customers. In FY25 we collaborated with other EDBs and retailers to develop a Load Management Protocol, to develop a consistent framework for aggregators to manage load on the network, while maintaining Orion's ability to respond to grid and network emergencies. During winter 2025, retailers controlled hot water on the network at scale for the first time. Retailer hot water control has scaled further and we are currently optimising our ripple control to get better utilisation of our assets.	Live	Various retailers
FY23	Resi-Flex	Exploring how to encourage flexibility from residential households by testing various commercial mechanisms with flexibility suppliers. This will directly benefit customers who provide flexibility through incentives and indirectly benefit all network customers by enabling decarbonisation at lowest cost. This project has been supported by Innovation Project Allowance and INTSA. During FY25, an expression of interest was run to select flexibility providers to partner with and co-design commenced. Trials with Octopus Energy included Saving Sessions and Intelligent Octopus, a managed EV charging service. In FY26 further retailers joined and initial learnings from the winter 2025 trial have been shared see Resi-Flex | The Orion Group	Live	Wellington Electricity, Octopus Energy, Ecotricity
FY25	Commercial and Industrial Flexibility (Stage 1)	Shifting commercial and industrial usage outside of peak times can have significant benefits for customers, the network, and electricity generation. This project focused on identifying and testing how to best engage commercial and industrial customers in flexibility initiatives. Stage 1 (Discover and Define) involved quantitative and qualitative research toward understanding of areas of value on our network and identify potential partners.	Complete (FY26)	Lumen consulting
FY26	Commercial and Industrial Flexibility (Stage 2)	Our INTSA application has been approved to support stage 2 (Enabling CPD Flexibility), developing and delivering flexibility trials with commercial and industrial customers. This is exploring C&I customers' capability for increased CPD response and testing operational enhancements to the CPD signal that can support broader adoption. https://www.comcom.govt.nz/assets/Uploads/Orion-Commercial-and-Industrial-Demand-Flexibility-Project-4-November-2025.pdf	Live	C&I customers
FY26	EECA Scaled Flex Project	This project is designed to test whether residential and community demand-side flexibility can provide a practical, scalable alternative to traditional network upgrades. It explores how households and community-scale resources can shift or reduce electricity demand at peak times, helping defer	Planned	EECA

Appendix H.1 Orion's innovation activity in FY26				
Start date	**Activity name**	**Description**	**Status**	**Collaborators**
		costly network investment while delivering fair value to participants. Through real-world trials, the pilot aims to build evidence on customer participation, commercial mechanisms, network benefits, and the systems required to enable flexibility at scale across New Zealand electricity networks.		
FY27	Valuing network deferral and non-traditional solutions	This ENA FNF marquee project aims to deliver an objective, repeatable and transparent approach to valuing non-traditional solutions that allow EDBs to defer or avoid investment in traditional network infrastructure, based on a consistent approach to quantifying the value of investment deferrals.	Planned	ENA Future Network Forum
FY27	Dynamic Capacity Management and Dynamic Operating Envelopes Implementation Framework	This ENA FNF marquee project aims to deliver a framework for constraint management and Dynamic Operating Envelopes (DOEs) across all voltages of electricity distribution networks. Phase one will establish standard methods, ready to be tested through field trials in phase two. This will help move towards dynamic, neutral capacity allocation for capacity constraint management, unlocking stranded network capacity and enabling better integration of distributed energy resources (DERs).	Planned	ENA Future Network Forum
FY23	Mobile Switching iPad app (Peek) for electronic Permits and other enhancements	Enhancements to our mobile app to gather field incident data and improve the safety and efficiency of field switching work. This involved design and specification with OEM (Synerty) of new and enhanced features to bring electronic permits and other enhancements into the mobile switching app. User testing was completed in FY26 and 105 devices have been issued with the latest version of Peek. This allows users to update our ADMS in the field, providing our Control Centre with real time information.	Complete (FY26)	Synerty
FY24	Artificial intelligence / Machine learning / advanced analytics	Explored artificial intelligence and machine learning methods and processes and tooling to provide advanced analytics for visibility, forecasting and flexibility applications. Trialled analytics with smart meter and LV monitoring data to identify use cases and insights. We learned that investments in data governance and a modern data platform enables faster development of AI and analytical projects. Continued investment in data governance and the Data Analytics Visualisation Engine (DAVE) platform has accelerated delivery of analytics, automation and AI, improving network visibility, standardising multi-source data, and reducing manual investigation through automated data and network issue detection. We scaled "everyday AI" via Microsoft Copilot to lift productivity in core tools (e.g., drafting, summarising, reporting, meeting prep). We also delivered bespoke AI agents—MoneyMate (self-service finance insights) and WorkMate (policy and guidance assistant)—showing the shift from experimentation to practical, scalable AI with measurable operational value.	Complete (FY26)	

Appendix H.1 Orion's innovation activity in FY26

Start date	Activity name	Description	Status	Collaborators
FY25	Advance drone technology – Substation trial	We previously trialled an automated unmanned aerial vehicle (UAV) to monitor the Norwood substation. This enabled the team to find faults and fix them before they caused outages. Over 200 trial flights were conducted to ensure suitability for substation sites, with minimal risk to people and infrastructure, while eliminating a repetitive task and freeing up our people for more valuable work. With successful trials completed, we are using the UAV to regularly monitor the site and are evaluating additional use cases.	Complete (FY26)	
FY25	Advance drone technology – Pole Top Inspection trial	Our Advanced Drone Technology programme trialled using unmanned aerial vehicles (UAVs) to do 6,000 Pole Top Inspections. We also explored how machine learning (ML) can make this process more effective and ultimately reduce staff time and costs, and improve asset management outcomes. Based on these learnings we are using UAVs to capture data and imagery of a further 20,000 pole tops to give us more accurate information of our assets and feed into several data processing platforms including an internal ML tool and our new asset information platforms. This data and imagery will also be used in the GridAware Tapestry trial.	Complete (FY26)	
FY26	GridAware lite grid management and intelligence platform trial	Collaboration between Orion, other EDBs, and Google Tapestry to provide and use collective asset imagery and datasets to train AI algorithms towards more efficient asset management and outage reduction. The trial aims to explore whether an external, automated platform could eventually streamline or even replace parts of our inspection and maintenance workflow.	Live	Google Tapestry, Northpower, Unison Networks and WEL Networks
FY25	Connections Journey Mapping – aligning EDB processes	We have been contributing to the Electricity Network Aotearoa (ENA) Future Network Forum (FNF)'s 'Connections Journey Mapping' project - aligning EDBs' processes to improve the connections journey for customers. 13 action points were identified to improve the customer journey, from pre-application right through to delivery. The first six quick-win outputs have been finalised and released to all EDBs for implementation (connections glossary, customer guide, journey steps, EDB self-serve manual, pre-application meeting template, and FAQs. We are currently contributing to three further workstreams: developing standardised commercial contracts for large DG and load connections, queue management policy and capacity maps.	Live	Major customers and the ENA Future Network Forum
FY25	Streamlining Customer Connections - Orion	We have made significant changes to our customer connections approach, including new proactive customer engagement and energy solutions roles, improved and updated customer guides and connection processes, and implementing new technology. Examples include implementing a new Customer Relationship Management database and using FutureGrid to determine any load or export limit issues and speed up approvals.	Live	EEA and ENA

Appendix H.1 Orion's innovation activity in FY26

Start date	Activity name	Description	Status	Collaborators
FY25	Community Energy Activator pilot	We collaborated with Ara Ake, Community Energy Network and others to pilot a Community Energy Activator in Canterbury. The twelve-week programme covering the topics in the 'Community Energy How To Guide' was piloted with nine community groups. We explored business models for community energy and batteries that could benefit both the network and communities. A learnings report and impact review was published in March 2025 and learnings shared at an event before Downstream 2025. In FY26 PowerCo also ran an Activator, and two more regions are planning to hold their own Activators, evidencing the scaling of this initiative through New Zealand.	Complete (FY26)	Ara Ake, Community Energy Network (CEN)
FY26	Resilience Explorer	We have been trialling a new Resilience Explorer tool by Urban Intelligence. The key lesson is that resilience only creates value when it's integrated into everyday asset decisions. Probabilistic hazard insights allow us to target investment where it matters most, rather than planning for extremes. We are sharing learnings with other EDBs including PowerCo and Unison, and exploring the opportunity to collaborate on resilience/adaptation modelling using Resilience Explorer.	Live	
FY26	Ara Ake Community Energy Challenge	The purpose of the Ara Ake Community Energy Challenge is to identify and pilot practical, scalable ways to share the benefits of locally generated solar energy across social housing portfolios, so that all tenants (not just those in solar equipped homes) can access more affordable and equitable energy, while protecting tenant choice and operating within existing network and regulatory settings in NZ.	Live	Ara Ake
FY27	Community Energy Case Study Framework	We are collaborating to develop a community energy case study framework that captures learnings and shares a range of case studies and blue prints, including non-network solutions and innovative business models that EDBs may support. We are working with three local communities to document three different examples of projects that may be optimised to maximise whole-of-system benefit and overcome regulatory, financial, and operational barriers. The desired outcome is community scale energy projects can become viable, resilient, and widely adopted across Aotearoa.	Planned	Ara Ake, CEN, communities, councils, UC, other EDBs

Appendix I – Schedule 17 Certification for year-beginning disclosures

We, Paul Munro and Mike Sang, being directors of Orion New Zealand Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

- the following attached information of Orion New Zealand Limited prepared for the purposes of clauses 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.
- 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.
- The forecasts in Schedules 11a, 11b, 11c, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Orion New Zealand Limited's corporate vision and strategy and are documented in retained records.

9 June 2026

Paul Munro — Date

Director

9 June 2026

Mike Sang — Date

Director